
**Report of the
Independent Inquiry**
into Hydraulic Fracturing
in the Northern Territory

28 November 2014

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Hydraulic Fracturing Inquiry
Level 2, Darwin Plaza
41 Smith Street
Darwin NT 0810

Tel: 08 8999 6009

HydraulicFracturing.Inquiry@nt.gov.au

The Hon Adam Giles MP
Chief Minister
Parliament House
DARWIN NT 0800

Dear Chief Minister,

I am pleased to present the Report of my Inquiry into hydraulic fracturing and the potential effects on the environment in the NT.

The major recommendation, consistent with other Australian and International reviews, is that the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime.

It is not yet known from the exploratory drilling programs whether commercial quantities of shale gas exist. In the event that there are exploitable opportunities, then it will take some years to turn them into production outcomes.

This timing is important for two major reasons.

First, the interregnum leads the Inquiry to recommend establishment of a Cabinet Sub-Committee to oversee the work required for the NT to set the standard for a best practice regulatory regime. It is at the political level that the balance can be struck between promoting shale gas production, setting the environmental management parameters, facilitating land access and fostering the NT's economic development.

The Cabinet Sub-Committee would be served by a Taskforce consisting of the related officials with the Secretariat provided by the DCM which would also provide the Chair at Executive Director level. This task should be capable of completion by the end of March 2015.

Second, the question of how the production will get to markets will be resolved as a result of the work that your Government has under way.

Having regard to the above, and the substantive weight of agreed expert opinion, the Inquiry finds that there is no justification whatsoever for the imposition of a moratorium on hydraulic fracturing in the NT.

The Inquiry also recommends that the Government:

- restructure the *NT Environmental Assessment Act* in the light of this Report and the proposed bilateral agreements with the Commonwealth on environmental assessments and approvals; and
- consider aligning the petroleum and mineral royalty frameworks.

The Executive Summary, which includes the recommendations and a taste of the findings, represents an abridged version of the rest of the Report *inter alia* provides the detailed response to the Inquiry's Terms of Reference.

I encourage you to publish the Report and seek feedback from the community about the recommendations and findings in a specific time frame. The Report should assist public debate and the response to it will inform you and your colleagues when you come to make the associated decisions.

May I take this opportunity to express appreciation for the Secretariat and their contribution to the work of the Inquiry. Robyn Green, Alaric Fisher and Emily Bonson are a credit to the NT public service.

Yours sincerely

A handwritten signature in black ink, appearing to read 'Allan Hawke'.

Allan Hawke AC
Commissioner
Hydraulic Fracturing Inquiry

28 November 2014

Executive Summary

Introduction

The Northern Territory Government (NTG) established the Inquiry on 14 April 2014 to undertake a thorough investigation into hydraulic fracturing for hydrocarbon deposits in the NT and the potential effects on the environment.

Among other things, the Chief Minister asked the Inquiry:

- ... to separate the proven evidence about environmental risk from the myths and to give an accurate picture based on science; and
- ... to provide recommendations on whether steps should be taken to mitigate any potential impacts from fracking.

These points and the Inquiry's Terms of Reference (which are reproduced at Annex C) are dealt with in detail throughout this Report.

The 263 submissions received were posted on the Inquiry website to inform interested parties and facilitate information exchanges.

Community meetings and consultations in Alice Springs, Darwin and Katherine attracted a combined attendance of around 150 people.

Discussions were subsequently held with individuals and organisations that provided submissions, including environmental groups, non-government organisations, petroleum industry and other associations, proponents, NTG agency officials and other interested people and bodies.

These processes provided further information, dovetailing with an allied research program to identify other sources of expertise and reference material that the Inquiry could draw upon during its investigations.

The top dozen issues raised by concerned citizens in order of their frequency were:

- water contamination;
- social, cultural and environmental impacts;
- water use;
- rivers and aquifers;
- health concerns;
- short term benefits;
- long term impacts;

- moratorium;
- monitoring and compliance;
- fugitive emissions;
- chemical usage; and
- the regulatory regime.

These concerns, which mirror those found in other enquiries, are unpacked under the related Term of Reference in the Report.

At first blush, the level of distrust and hostility towards the unconventional gas industry might seem curious given the NT's history of fracking in conventional reserves, without adverse consequences. That is not to downplay the need to manage risk which, like the possibility of human error, is always present, but advances in technology and techniques to manage risk have gone ahead in leaps and bounds over the last 40 years.

The relatively recent move to horizontal as well as vertical fracturing for unconventional gas resources seems to have triggered some latent community concerns. By way of an aside, the industry has not helped itself through the use of terms such as “unconventional”, “abandoned” wells and “fracking” itself, which provoke people's emotional responses, confounding rational discussion of hydraulic fracturing technology and related issues.

It was apparent from submissions, public meetings and discussions that there is confusion or poor understanding within the community about some aspects of hydraulic fracturing. For example, there is considerable confusion between Coal Seam Gas (CSG) extraction (which frequently does not involve fracturing) and fracturing for the extraction of shale gas, which is the main target of hydraulic fracturing for hydrocarbons in the NT.

CSG exploitation has attracted the ire and attention of the Lock the Gate movement and kindred spirits, and the high profile of this issue has led to public concern about “fracking” in any form.

In response to claims that CSG was banned in the NT, the Inquiry understands no CSG resources that can be exploited have been found in the NT, but exploration for and extraction of CSG by conventional methods (which includes hydraulic fracturing) is not excluded under the *Petroleum Act*.

Nevertheless, fracking and the unconventional gas industry have served as a proxy in the eastern States and the NT for a more deeply held opposition to fossil fuels *per*

se. This ideological position has been fanned by documentaries such as Josh Fox's Gasland (2010)¹ and The Sky is Pink (2012), while Phelim McAleer presents an alternative view in FrackNation (2013).

The Inquiry was informed by recent reports from overseas and Australian jurisdictions touched on below and dealt with in more detail in the Report.

International Reports

Four International Reports of particular relevance to this Inquiry were considered:

- the New Zealand Parliamentary Commissioner for the Environment (Dr Jan Wright), Interim Report of November 2012, "Evaluating the Environmental Impacts of Fracking in New Zealand";
- Dr Wright's Final Report in June 2014, "Drilling for Oil and Gas in New Zealand: Environmental Oversight and Regulation";
- the Council of Canadian Academies' 2014 Report, "Environmental Impacts of Shale Gas Extraction in Canada" following an investigation by The Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction; and
- the Royal Society and the Royal Academy of Engineering, June 2012 Report, "Shale Gas Extraction in the UK: a Review of Hydraulic Fracturing" following the UK Government Chief Scientific Adviser's request to carry out an independent review of the scientific and engineering evidence relating to the technical aspects of the risks associated with hydraulic fracturing to inform government policy making about shale gas extraction in the UK.

Major conclusions from these enquiries are reported below, and relevant evidence and conclusions are referenced throughout this Inquiry Report. These enquiries were carried out by eminent people in their fields and their range of expertise as well as those of the independent peer review panels can be viewed when accessing their reports.

The New Zealand Parliamentary Commissioner for the Environment's Interim Report

"... dealt with the whole process of drilling for oil and gas, from choosing a well site right through to the abandonment of the well."

Dr Wright concluded that fracking can be managed effectively provided that operational practices are implemented and enforced through regulation. Her Final

¹ A more complete analysis of this documentary can be found at Energy in Depth, 'GasLand Debunked', <http://energyindepth.org/wp-content/uploads/2011/11/Debunking-Gasland.pdf>

Report evaluated Government oversight and regulation for managing the environmental risks of the industry, finding them not to be adequate and leading to six recommendations about necessary improvements.

The Council of Canadian Academies (CCA) Panel comprised 14 experts, whose work and draft report was peer reviewed for its objectivity and quality by a group of ten eminent people selected by the Council for their diverse perspectives, areas of expertise, and broad representation of academic, industrial, policy and non-governmental organisations. The CCA Report proposed a framework of five distinct elements to manage effectively the risks associated with shale gas development.

The Royal Society and the Royal Academy of Engineering Panel comprised eight experts; its Report was similarly peer reviewed by an independent panel of eight experts, while four others commented on sections of the draft.

The UK Report found that:

“The health safety and environmental risks associated with hydraulic fracturing as a means to extract shale gas can be managed in the UK as long as operational best practices are implemented and enforced through regulation. Hydraulic fracturing is an established technology that has been used in the oil and gas industries for many decades.”

The UK has 60 years’ experience of regulating onshore and offshore oil and gas.

Australian Reports

The Inquiry also had regard to the approaches in other Australian jurisdictions, which are touched on below and dealt with in more detail in the Report.

Of particular interest, is the detailed review by the Australian Council of Learned Academies (ACOLA).

ACOLA undertook a three year research program funded by the Australian Research Council, conducted for the Prime Minister’s Science, Engineering and Innovation Council (PMSEIC) through the Chief Scientist and his Office.

ACOLA is a forum that brings together great minds, broad perspectives and knowledge, providing the nexus for true interdisciplinary co-operation to develop integrated problem solving and cutting edge thinking on key issues for the benefit of Australia. This interface combines the strengths of the four Learned Academies, the:

- Australian Academy of the Humanities;
- Australian Academy of Science;

- Academy of the Social Sciences in Australia; and
- Australian Academy of Technological Sciences and Engineering.

PMSEIC identified a series of six research topics under the “Securing Australia’s Future” heading to deliver research-based evidence and findings to support policy development in areas of importance for Australia’s future.

The relevant ACOLA review is “Engineering Energy: Unconventional Gas Production”, which focused on shale gas in Australia, with a Final Report in May 2013. The Expert Working Group for the review comprised:

- Professor Peter Cook CBE, FTSE;
- Dr Vaughan Beck FTSE;
- Professor David Brereton;
- Professor Robert Clark AO, PSM, FRSN;
- Dr Brian Fisher AO, PSM, FASSA;
- Professor Sandra Kentish;
- Mr John Toomey FTSE; and
- Dr John Williams FTSE.

ACOLA’s Report (except for the conclusions and recommendations) was peer reviewed by an independent panel of experts comprising:

- Professor Hugh Possingham FAA;
- Professor Lesley Head FASSA, FAHA; and
- Professor John Loughhead FREng, FTSE, OBE.

The ACOLA Report Summary said that:

“A number of environmental issues related to the shale gas industry have arisen in the United States and similar questions have been raised about potential impacts in Australia. A large number of impacts are possible, but the likelihood of many of them occurring is low and where they do occur, other than in the case of some biodiversity impacts, there are generally remedial steps that can be taken. Nonetheless it is important that the shale gas industry takes full account of possible adverse impacts on the landscape, soils, flora and fauna, ground water and surface water, the atmosphere and on human health in order to address people’s concerns. This will require improved baseline studies against which to measure future change and to compare natural change and change resulting from industry activities. The footprint and regional scale over which shale gas operations may occur can be minimised by measures such as drilling multiple wells from one drill pad, but nonetheless there will be some cumulative

regional, ecological and hydrological impacts, including fragmentation of habitats and overall landscape function. These will need to be carefully assessed and managed using best practice.”

The ACOLA Report includes important findings in relation to landscape and biodiversity, water, induced seismicity, greenhouse gas emissions, community issues, and monitoring, governance and regulation.

On chemical and water management, the Report says:

“Contamination of aquifers and surface water can result from chemical spillage. The industry already has rigorous systems for dealing with spillage, or from the incorrect disposal of the hydraulic fracturing fluid (already controlled by regulators under most jurisdictions), or from produced water. Contamination can also potentially occur via leakage from a borehole into a freshwater aquifer, due to borehole failure, particularly from abandoned bores, or (though less likely) from an incorrect hydraulic fracturing operation. These are unlikely to occur if best practice is followed, but regulations need to be in place and enforced, to help to ensure this.”

In relation to monitoring and regulation, the Report concludes:

“Monitoring of shale gas production and impacts is likely to be undertaken by petroleum companies as part of their normal operations, but in order to win community confidence, truly independent monitoring will need to be undertaken by government or other agencies and/or credible research bodies. Induced seismicity, aquifer contamination, landscape and ecosystem fragmentation, greenhouse and other emissions to the atmosphere, together with potentially adverse social impacts, are all likely to be areas of community concern that will need to be monitored and for which baseline surveys will be required. It will not be feasible to monitor large areas for extended periods of time and therefore monitoring will need to be carefully and cost effectively targeted to answer specific questions and transparently address particular concerns. This will require a robust regulatory regime, which will build on existing regulations and which will also fully take account of the need for sensible and multiple land use, based around well-resourced regional planning and cumulative risk assessment.”

Issues around “social licence” for gas extraction operations were raised in many submissions and have been addressed in other enquiries. The ACOLA Report notes:

“Gaining and retaining a “social licence to operate” will be important to all shale gas operations and will need to be approached not just as a local community issue, but also at regional, state and national levels. In order to develop effective relationships with communities potentially impacted by shale gas developments, it will be necessary to have open dialogue, respect and transparency. It will also be important there is confidence in the community that not only are shale gas operations and impacts being effectively monitored, but also that concerns will be identified and remediated, or operations stopped before a serious problem arises. Many of the most prospective areas for shale gas are subject to Native Title or are designated Aboriginal Lands and it will be important to ensure that traditional owners are aware of the nature and scale and the possible impact of shale gas developments from the start. The industry also has the potential to help address the aspirations of Aboriginal people to build greater economic self-sufficiency.”

Recommendation

It is recommended that the NT Government propose through the COAG Standing Council on Energy and Resources that ACOLA host a workshop of international academics to consider their collective findings, learn from each other and identify the findings shared by all of the academics.

The Commissioner understands that the Commonwealth Department of Industry support such a proposal and have a funding model in mind to that end.

This Inquiry focused on issues associated with shale gas extraction and the associated tight gas extraction. As well as the Commonwealth ACOLA Report, most other States have conducted their own enquires as described below.

New South Wales

The Chief Scientist and Engineer (CSE), Professor Mary O’Kane, delivered her Independent Review of Coal Seam Gas Activities in NSW - Study of Regulatory Compliance Systems and Processes for Coal Seam Gas to the NSW Premier on 30 September 2014 (the final of three volumes). The CSE found that CSG mining in NSW was manageable subject to appropriate safeguards.

Queensland

CSG production is under way in various areas, with hydraulic fracturing as part of the extraction process. To support commercialisation of the resources, significant investments are being made in constructing liquefied natural gas (LNG) facilities at Gladstone and the associated pipelines to connect gas fields to the new facilities.

To manage compliance and enforcement, the Queensland Government established the CSG Compliance Unit (formerly the LNG Enforcement Unit) which includes *“multi-disciplinary industry and environmental staff from across government, including environmental and ground water experts, petroleum and gas safety specialists and staff specialising in land access issues”*.²

The Inquiry observed that levels of community acceptance vary in different parts of the State and there has been significant public commentary and activity against the industry in some areas. As part of their commitment to give the community a stronger voice in the industry’s development, the Government set up the GasFields Commission - a statutory body to manage the coexistence of rural land holders, communities and the CSG industry.

South Australia

In launching South Australia’s “Road Map for Unconventional Gas Projects” in December 2012 the Minister for Mineral Resources and Energy, the Hon Tom Koutsantonis, said:

Our vision is for environmentally sustainable and commercially rewarding unconventional gas projects in South Australia to contribute to the wellbeing and quality of life of our communities for decade to come. The commercialisation of the State’s vast unconventional gas resources will contribute to welcomed, safe, secure and competitive energy supplies for future generations.

The South Australian regulatory system, which features a single portal for industry and regulatory bodies, is often cited as the benchmark for other jurisdictions.

Tasmania

While Tasmania has no history of hydrocarbon production or hydraulic fracturing, one explorer has recently started looking at the potential of areas in southern Tasmania to host oil and gas within an unconventional reservoir (the Woody Island Siltstone).

² <https://www.business.qld.gov.au/industry/csg-lng-industry/regulatory-framework-csg-lng/enforcement-compliance>

Tasmania is unlikely to experience significant hydraulic fracturing due to geological constraints. A moratorium on hydraulic fracturing is currently in place until March 2015 and an issues paper was recently released for public comment.³

Victoria

Exploration for unconventional gas started in the early 2000s with tight gas discovered in the Gippsland region. As a result of an Inquiry, in May 2012 the Parliament's Economic Development and Infrastructure Committee made 25 recommendations on a wide range of matters including establishing processes to enable community engagement for Coal Seam Gas exploration, implementation of the National Harmonised Framework and outcome focused work approvals to manage risks better.

The Hon Peter Reith's Gas Market Task force provided their final Report and recommendations together with a Supplementary Report to the Victorian Premier in October 2013.

Approvals for new onshore gas exploration licences, hydraulic fracturing and onshore gas exploration drilling are on hold pending the Victorian election.⁴

Western Australia

The Parliamentary Committee on Environment and Public Affairs is conducting an Inquiry into the Implications of Hydraulic Fracturing for Unconventional Gas. Since August 2013, this Inquiry has been exploring four key points:

- how hydraulic fracturing may impact on current and future uses of land;
- the regulation of chemicals used in the hydraulic fracturing process;
- the use of ground water in the hydraulic fracturing process and the potential for recycling of ground water; and
- the reclamation (rehabilitation) of land that has been hydraulically fractured.

It remains unclear when the Inquiry will conclude its work.

Report Structure

The Inquiry's Report comprises six Chapters;

- Chapter One - Introduction: provides context around formation of the Inquiry, the processes established to address the Terms of Reference, an overview of the unconventional gas industry, and its potential in a national and global context;

³ [http://dpiipwe.tas.gov.au/about-the-department/review-of-hydraulic-fracturing-\(fracking\)-in-tasmania](http://dpiipwe.tas.gov.au/about-the-department/review-of-hydraulic-fracturing-(fracking)-in-tasmania)

⁴ <http://www.parliament.vic.gov.au/publications/research-papers/8927-unconventional-gas-coal-seam-gas-shale-gas-and-tight-gas>

- Chapter Two - What the Inquiry Heard: the Inquiry sought to hear from people involved in or affected by the unconventional gas industry and/or interested members of the NT community through submissions, a series of community forums and meetings with interested people and industry groups. This process identified themes and issues for the Inquiry to consider during its work;
- Chapter Three - Hydraulic Fracturing: provides scientific information and evidence about hydraulic fracturing and an overview of globally recognised Reports which the Inquiry has drawn upon;
- Chapter Four - Exploring the Terms of Reference: provides a history of hydraulic fracturing in Australia and in the NT and explores the underlying challenges specific to the NT that may constrain future production;
- Chapter Five – specifically addresses Term of Reference Seven: by exploring effective methods for mitigating potential environment impacts before, during and after hydraulic fracturing; and
- Chapter Six - Other Aspects: deals with other matters important to consider.

Conclusions

Allan Mazur’s seminal exposition “Disputes between Experts” comes readily to mind in the current context. Fortunately, there is a considerable body of informed opinion (such as that cited above) from Australia and around the world which allows separation of the wheat from the chaff, guidance on the issues associated with fracking and how to de-risk them. In the light of this eminent expertise, it’s incumbent upon us to recognise and act on that.

Recommendation

This Inquiry’s major recommendation, consistent with other Australian and International reviews, is that the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime.

NSW and Victorian Reports into CSG mirror this Inquiry’s work on shale gas, explore the same sorts of issues and come to very similar conclusions.

Recommendation

The substantive weight of agreed expert opinion leads the Inquiry to find that there is no justification whatsoever for the imposition of a moratorium of hydraulic fracturing in the NT.

Results are not yet to hand for the NT exploratory drilling programs so whether there are commercial quantities of shale gas that can be exploited is unknown.

In the event that there are exploitable opportunities, then it will take some years to turn them into production outcomes. This timing is important for a number of reasons.

First, how will the production get to market?

At least two options are possible.

Subject to connectivity from production sites to the existing NT north-south pipeline, INPEX, Conoco or another party could decide to build another LNG train in Darwin to take that gas.

The other option would involve extending the north-south pipeline to Mount Isa or Moomba to hook up with the eastern seaboard grid, a proposal that the NT Government is pursuing vigorously with industry and the Commonwealth as a Project of National Significance. Such a pipeline may also ameliorate the difficulties in sourcing competitively priced long-term gas contracts as the Queensland LNG Projects draw supplies north and push up prices. Commercial interests are already conducting feasibility studies into the pipeline extension.

Second, the delay from discovery to production provides the window to put in place a robust regulatory regime aimed at setting the standard for best practice.

The NT Environmental Defenders Office' submissions of 4 July and 31 October 2014 provide a comprehensive review of best practice regulatory frameworks for hydraulic fracturing operations.

Recommendation

The Inquiry recommends that a Cabinet Sub-Committee be formed, chaired by the Deputy Chief Minister and comprising the Ministers whose portfolios cover Lands, Planning and the Environment; Land Resource Management; Mines and Energy; and Primary Industry and Fisheries to oversee the work required for the NT to set the standard for a best practice regulatory regime.

The Cabinet Sub-Committee would be served by a Taskforce consisting of the related officials with the Secretariat provided by the DCM which would also provide the Chair at Executive Director level.

This work should be initiated as soon as possible with a view to completing the task by the end of the first quarter in 2015. Most of what is required already exists, but is scattered among Departments and the gaps that have to be filled have been identified.

The Inquiry believes that this is the way to get real reform, real debate, real discussion and real understanding of the issues. It's at the political level that the balance can be struck between promoting Shale Gas development, setting the environmental management parameters, facilitating land access and fostering the NT's economic development.

In undertaking this task, the Cabinet Sub-Committee and Taskforce would take into account the guidance and findings of this Report, the 2013 COAG Standing Council on Energy Resources paper titled "The National Harmonised Regulatory Framework for Natural Gas from Coal Seams", as well as approaches and practices in other jurisdictions, such as South Australia.

It is also relevant that the Commonwealth Government is endeavouring to deliver a "One Stop Shop" for environmental approvals that will:

- accredit State/Territory planning systems under national environmental law; and
- create a single environmental assessment and approvals process for nationally protected matters.

The "One Stop Shop" policy, to be delivered through bilateral agreements, aims to simplify the approvals process for proponents while maintaining high environmental standards, including through the Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development Water Resources, which will continue to be included in the *Environment Protection and Biodiversity Conservation Act* as a matter of national environmental significance.

No change to the environmental standards under the EPBC Act are foreshadowed, so water trigger projects will still have to go through two separate approval processes.

The NTG/Commonwealth Bilateral Assessments Agreement is expected to come into effect in the near future.

Work is now progressing on the Approvals Bilateral.

Recommendation

The Inquiry recommends that the *NT Environmental Assessment Act* be restructured in the light of this Report and the proposed bilateral agreements with the Commonwealth on environmental assessments and approvals.

The Inquiry became aware of differences between the calculation method of royalties from petroleum and mining activities. The current system for petroleum may act to discourage investment in developing unconventional gas in the NT.

Recommendation

The Inquiry recommends that the NT Government consider aligning the petroleum and mineral royalty frameworks.

The Board Room Series Report “Positioning for Prosperity for Developing the North” concludes that there is agreement about growth being imperative for the NT and identifies five broad categories:

- agriculture;
- energy and resources;
- infrastructure development;
- international education; and
- tourism.

The NTG might also wish to consider establishing Cabinet Sub-Committees to deal with the other issues identified there.

By way of comparison, Queensland has set up four Cabinet Sub-Committees dealing with agriculture, property and construction, resources and tourism.

Recommendations

The Inquiry’s major recommendation, consistent with other Australian and International reviews, is that the environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime.

The Inquiry recommends that the NT Government;

- form a Cabinet Sub-Committee, chaired by the Deputy Chief Minister and comprising the Ministers whose portfolios cover Lands, Planning and the

Environment; Land Resource Management; Mines and Energy; and Primary Industry and Fisheries to oversee the work required for the NT to set the standard for a best practice regulatory regime;

- the *NT Environmental Assessment Act* be restructured in the light of this Report and the proposed bilateral agreements with the Commonwealth on environmental assessments and approvals;
- consider aligning the petroleum and mineral royalty frameworks; and
- propose through the COAG Standing Council on Energy and Resources that ACOLA host a workshop of international academies to consider their collective findings, learn from each other and identify the findings shared by all of the academies.

The substantive weight of agreed expert opinion leads the Inquiry to find that there is no justification whatsoever for the imposition of a moratorium of hydraulic fracturing in the NT.

Findings

Chapter Five comprises a detailed examination of the Inquiry's seventh Term of Reference which will form part of the proposed Cabinet Sub-Committees work.

Rather than repeat those findings here, each of the following sections provides a taste of what is envisaged. The complete set of findings from Chapter Five are also reproduced at Annex F.

5.1: Selection of Well Sites and Use of Single or Multiple Well Pads (ToR 7.1 and 7.9)

The environmental (including social and cultural) impact of individual well pads is likely to be small and readily mitigated, but the cumulative impact of extensive well development over a gas play may be significant. The use of multiple well-pads is likely to reduce the environmental footprint of unconventional gas development.

5.2: Well Design, Construction, Standards, Control and Operational Safety and Well Integrity Ratings (ToR 7.2)

Ensuring well integrity is a key aspect of reducing the risk of environmental contamination from unconventional gas extraction. Application of leading practice in well construction combined with rigorous integrity testing and effective regulatory oversight should result in a very low probability of well failure, but a

ground water monitoring regime that can detect contamination attributable to unconventional gas activities is also desirable.

5.3: Water Use (ToR 7.3)

Unconventional gas extraction has water requirements for drilling and hydraulic fracturing that are small in the context of many other licenced water uses, but which need to be managed carefully to ensure sustainability at a local or catchment/aquifer scale. Conflict with other water users can be reduced by the use of saline ground water or recycled water where feasible.

5.4: Chemical Use (ToR 7.4)

Chemicals used during hydraulic fracturing generally pose a low environmental risk, providing that leading practice is applied to minimising surface spills and managing flowback water after fracturing. Public concern about chemical use will be reduced by a transparent, full disclosure policy.

5.5: Disposal and Treatment of Waste Water and Drilling Muds (ToR 7.5)

Waste water management issues are similar to many other mining and industrial processes, although treatment of produced water following fracturing may have some unique elements. On-site treatment and recycling are desirable where possible, but the use of reinjection for waste water disposal will require further investigation to test whether it can be applied in Australia.

5.6: Fugitive Emissions (ToR 7.6)

Accurate monitoring of, and accounting for, fugitive emissions during unconventional gas production - including during well completion and following well closure - are critical to understanding life-cycle greenhouse gas emissions. Reduced emission completions (“green completions”) will contribute to minimising fugitive emissions.

5.7: Noise (ToR 7.7)

Noise is one of a number “nuisance” impacts associated with unconventional gas extraction, although noise impacts occur primarily for a limited time during drilling and fracturing, and may not be a significant factor in most remote locations.

5.8: Monitoring Requirements (ToR 5.8)

Robust monitoring regimes will be crucial to the effective management and regulation of a developing unconventional gas industry in the NT, and that

monitoring requirements in addition to those for standard regulatory compliance should be carefully considered.

5.9: Rehabilitation and Closure of Wells (Exploratory and Production) including issues associated with Corrosion and Long Term Post Closure and Site Rehabilitation for areas where Hydraulic Fracturing Activities have Occurred (ToR 7.10 and 7.11)

Application of leading practice for construction and closure can minimise environmental risks associated with decommissioned wells, but the longevity of long-term integrity of decommissioned wells remains poorly understood.

5.10: Induced Seismicity

There is a low risk of seismicity of an intensity that will be felt or cause damage at the ground surface, but risks from induced seismicity can be minimised through leading practice planning, management and monitoring of fracturing operations.

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Chapter One - Introduction

1.1 About the Inquiry

The Honourable Peter Chandler, Minister for the Environment, announced on 20 February 2014 he had recommended that the Government initiate an Inquiry into hydraulic fracturing in the NT and the potential effects on the environment.

A copy of the Minister's Media Release is at Annex A.

On 19 March 2014, the Honourable Adam Giles, Chief Minister, announced the Commissioner's pending appointment, saying *inter alia*, that he had ordered a thorough Inquiry:

- ... to separate the proven evidence about environmental risk from the myths and to give an accurate picture based on science; and
- ... to provide recommendations on whether steps should be taken to mitigate any potential impacts from fracking.

See Annex B for the Chief Minister's associated Media Release.

The Terms of Reference for the Inquiry are at Annex C.

After being officially appointed as the Commissioner under the provisions of the *NT Inquiries Act* on 14 April, Dr Allan Hawke AC called for public submissions to help inform development of a Report to the NT Government before the end of 2014 (see Annex D).

The Inquiry set out to:

- respond to the Terms of Reference using evidence-based, factual research to explore the topics and to provide a solid foundation for the recommendations and findings;
- provide opportunities for the community, industry, peak groups and any interested party to submit information and thoughts for consideration;
- draw on existing research and case studies in addition to information gained through submissions and meetings; and
- ensure information sources were identified and examined.

The Inquiry maintained an independent approach to its activities without direction or influence.

Associated issues were also examined on the basis that they are inextricably linked to the onshore gas industry and would impact on the Inquiry's findings and recommendations. The Inquiry felt that the recommendations should take into account the broader issues and context.

1.1.1 Inquiry Process

The Inquiry followed a four stage process:

- planning and administration;
- information gathering;
- analysis, assessment and consolidation; and
- report preparation.

The stages were undertaken concurrently to ensure the Inquiry's work was coordinated, progress was maintained and timeframes met.

Planning and Administration

This first stage involved logistical arrangements such as establishing an office, recruiting a small team to support the Commissioner, confirming document filing, security and management matters and developing the Inquiry website (www.hydraulicfracturinginquiry.nt.gov.au).

In defining the scope of the Inquiry, the primary research and lines of investigation focused on Shale Gas. The distinct differences between shale gas and other types of gas are discussed later in this Chapter - the NT's onshore resources are predominantly shale gas. The Inquiry recognised that limiting all research to the shale gas industry might be counterproductive and in some instances limiting, so it did not exclude information purely on that basis.

Information Gathering

This phase had six main activities which provided a thorough information basis from which the Inquiry could make the necessary analysis and assessments:

- public submission were called for on 15 April 2014. Initially, submissions were to close on 31 May 2014, but due to a high level of interest, this period was extended to 30 June 2014. Submissions and addendums received after this date were also accepted and considered. All submissions were placed on the Inquiry website to ensure transparency and cross referencing, while enabling the information presented to be challenged or queried by others. Annex E provides details of the 263 submissions received. An assessment of the terms and topics

raised by submissions was undertaken and the results are presented in Chapter Two;

- three public forums were held in Alice Springs (9 July), Darwin (12 August) and Katherine (7 August) hosted and coordinated by the Arid Lands Environment Centre (Alice Springs) and the Environment Centre NT (Darwin and Katherine). The forums allowed community members to share their thoughts on hydraulic fracturing and raise questions or matters for the Inquiry to consider. Those issues are also elaborated on in Chapter Two;
- each organisation which provided a submission to the Inquiry, and selected individuals, were invited to meet with the Commissioner to discuss their views in further detail. These meetings also provided an opportunity for the Commissioner to question material and assertions and seek further information and/or clarification. Interviews were also conducted with authors and contributors to recent reports into unconventional gas activities in Australia. The interviews were conducted in person or via teleconference; most took place in July and August;
- on 16 and 17 September 2014, the Inquiry inspected conventional and unconventional gas operations utilising hydraulic fracturing in the Moomba basin. This visit, coordinated by Santos, enabled the Inquiry to see hydraulic fracturing “in action” and the management systems associated with a large oil and gas field. Activities observed included well drilling and casing; hydraulic fracture spreads, fracturing fluid chemical management and well pressure monitoring; management of flowback fluids, flaring and condensate separation; water and waste water management; use of multiple well pads and directional drilling; gas and oil collection and processing facilities; environmental monitoring; and work health and safety systems. Ongoing consultation and engagement by Santos with Aboriginal native title holders and local pastoralists, who have maintained organic beef certification for lands surrounding the operating oil and gas wells and Indigenous employment initiatives were also noted;
- the Commissioner also visited operations around Miles and Roma in Queensland during a two day site visit on 23 and 24 September hosted by Origin Energy. While providing the opportunity to see an operational gas plant and frac spread/drilling sites, the visit also covered water treatment and reuse, land access through Conduct and Compensation Agreements between Origin and land holders, cooperative arrangements with land owners, and a meeting with Maranoa Regional Councillors to discuss the CSG industry and the related Joint Maranoa Regional Community Consultative Committee.

- the Commissioner met with regulators in Queensland and South Australia and from various Government departments (Federal, State and NT) responsible for state development, mining and energy, environment and regulation. These discussions provided the Inquiry with a better understanding of how other jurisdictions have managed the onshore unconventional gas industry, critical issues and lessons learnt, particular areas of environmental risk and role of industry in the broader state development framework;
- significant desktop research was undertaken, with a range of independent reports providing a critical evidence base for the Inquiry. These reports, which focused on shale gas or onshore unconventional gas operations, included:
 - o “Engineering Energy: Unconventional Gas Production. A Study of Shale Gas in Australia” (2013) by the Australian Council of Learned Academies (commonly referred to and referenced in this report as the “ACOLA Report” or “ACOLA”);
 - o “Golden Rules for a Golden Age of Gas: World Energy Outlook Special Report on Unconventional Gas” (2012) by the International Energy Agency (IEA);
 - o “Gas Market Taskforce: Final Report and Recommendations” (2013) by the Taskforce led by the Hon Peter Reith (Referenced as Gas Market Taskforce);
 - o “Independent Review of Coal Seam Gas in New South Wales” (2014) by the Chief Scientist and Engineer (referenced as Professor O’Kane);
 - o “Shale Gas Extraction in the UK: a Review of Hydraulic Fracturing” (2012) by the Royal Society and Royal Academy of Engineering (referenced as RSRAE)
 - o “Evaluating the Environmental Impacts of Fracking in New Zealand: An Interim Report” (2012) by the Parliamentary Commissioner for the Environment, followed by “Drilling for Oil and Gas in New Zealand: Environmental Oversight and Regulation” (2014) by the Parliamentary Commissioner for the Environment (referenced as PCE);
 - o “Environmental Impacts of Shale Gas Extraction in Canada” (2014) by the Council of Canadian Academies (referenced as CCA) and
 - o “Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing” (2014) by the Expert Panel appointed by the Verschuren Centre for Sustainability in Energy and the Environment at Cape Breton University (referenced as NSIRP).

Importantly, these reports discussed associated risks and potential mitigation strategies for their management which were directly related to the Inquiry’s Terms of Reference. Where necessary, the authors were contacted for further information

and clarification. The Executive Summary and Chapter Three cover particular points of interest. Additional information was sourced from journals, publications and other reports and sources.

The information available about hydraulic fracturing and the onshore gas industry is dynamic, compounded by how different jurisdictions are managing local policy positions. The Inquiry endeavoured to keep up to date with developments and to the best of its knowledge, the information within this Report is current at the time of its finalisation.

Analysis, Assessment and Consolidation

Submissions and research material were analysed and further information requested. Organisations and individuals were contacted to clarify points of contention, request further detail and seek confirmation of statements provided. Through the Inquiry process, questions were put to the Commissioner about the validity, completeness and accuracy of information provided in submissions. These were followed up and the responses considered. People whose oral comments had been quoted to the Inquiry by third parties were asked to confirm their remarks, clarify the context and respond (confirm or rebut) where necessary. Information about alleged incidents which were quoted as leading to operational failures or negative environmental impacts was sought to confirm the known facts and response by regulators and operators.

Issues being considered by the Inquiry were tested with independent experts, industry representatives, stakeholder organisations and other States. Sections of the report were also provided in confidence to some interlocutors to ensure accuracy of information and conclusions, while in some cases information about specific organisations or reference to particular individuals was provided to confirm accuracy. Recommendations were debated and developed in response to the Terms of Reference based on the balance of information and evidence available to the Inquiry as at 27 November 2014. The implications of proposed recommendations were also considered and tested against best practice measures to ensure implementation of the recommendations would deliver balanced outcomes for the NT.

Report Preparation

Report preparation took place in concert with other stages of the Inquiry to ensure information was captured and documented along the way.

1.1.2 Challenges for the Inquiry

Challenges faced by the Inquiry in undertaking its work are set out below.

Verification of Information

Very significant volumes of information and commentary are available on hydraulic fracturing and its associated aspects, and the Inquiry had a considerable amount of information presented to it or identified through research. Given “fracking” is a highly emotive issue with polarised views, there were instances where information was presented - either in full or in part - to suit a particular argument or view. In some instances, claims were anecdotal without scientific or evidence-based linkages. While the Inquiry did not dismiss this type of anecdotal information or the underlying concerns expressed through the material, it accessed the source document and spoke to relevant authorities where possible, formed a clear understanding of the authors/developers’ intent and interrogated the information from multiple angles. Articles and reports which had been peer reviewed were considered to have a high level of integrity and rigour from which findings and positions were drawn. The Inquiry’s experience reinforced the need for evidence-based research, scientific data and ongoing monitoring to build a shared understanding of the industry and operational impacts on the local environment. This was a consistent theme that also emerged from the findings of other significant enquiries and studies.

Limited General Understanding about the Topic

The onshore oil and gas industry, and its associated terminology, practices and concepts is highly complex and technical. It can be challenging to explain such complex information in plain English without inadvertently missing nuances and underlying factors through over simplification. That hydraulic fracturing can occur thousands of metres underground and therefore out of sight, makes an already difficult task even more challenging. Throughout the Inquiry, a lack of understanding about the “basics”, such as the different types of gas, the nature of the NT gas resources, as well as the associated risks was apparent. To this end, the Report includes a brief explanation of the gas industry and processes to assist understanding and provide a shared knowledge for discussion. This information has been drawn primarily from the CSIRO as well as other credible independent sources.

Scope of the Terms of Reference

Throughout the consultation, many organisations and individuals expressed concern that the Terms of Reference were too narrow and did not cover the full range of issues associated with hydraulic fracturing. This is discussed in more detail in the Chapter Two: “What the Inquiry Heard”. The Commissioner decided at the outset to accept all information provided by the public and organisations, interpreting the Terms of Reference as providing a focal point for the Inquiry’s work, rather than a means of limitation.

Consideration of all Aspects

Many perspectives and opinions on hydraulic fracturing and onshore gas extraction are evident and all views put forward were explored. Associated issues also emerged and these have been addressed and considered to assist a thorough and complete set of recommendations and increased community and industry confidence in the process. The Inquiry team kept abreast of developments with various related issues and assessed their validity and impact on this Report during its work.

1.1.3 Terminology Used in this Report and the Terms of Reference

In acknowledging the highly technical nature of the subjects that the Inquiry was charged with investigating, minimal jargon and non-technical terms are used where possible.

The Inquiry identified and agreed how to define particular terminology used in the Terms of Reference. These definitions are provided here to support readership and understanding of this Report. Technical, industry-specific and scientific terms, such as well integrity and fugitive emissions are defined alongside the technical discussion of each area of investigation under Term of Reference 7, see Chapter Four and particularly Chapter Five.

While the term does not appear independently within the Terms of Reference, the Inquiry focused on the risks to, impacts on, and mitigation strategies for the protection of the “environment” arising from hydraulic fracturing and the processes that would be associated with exploitation of shale gas. This requires some explanation to provide context and scope.

Accordingly, the Inquiry looked to existing legislation to identify how the NT defines **environment**.

Section 3 of the *Environment Assessment Act* states “environment means all aspects of the surroundings of man including the physical, biological, economic, cultural and social aspects.”

Part V of the *Petroleum Act* defines environment as “land, air, water, organisms and ecosystems and includes:

- a) the well-being of humans;
- b) structures made or modified by humans;
- c) the amenity values of an area; and
- d) economic, cultural and social conditions.”

The *Petroleum Act* definition is consistent with that contained in the *Mining Management Act*, with the notable difference being the *Mining Management Act* definition refers to “the mine site” rather than “an area” as above.

To provide a complete picture, three additional definitions from the *Petroleum Act* are provided:

- **“Environmental Harm** means:
 - (a) any harm to or adverse effect on the environment; or
 - (b) any potential harm (including the risk of harm and future harm) to or potential adverse effect on the environment, of any degree or duration and includes environmental nuisance.
- **Environmental Nuisance**, in relation to land, means:
 - (a) an adverse effect on the amenity of the land caused by noise, smoke, dust, fumes or odour; or
 - (b) an unsightly or offensive condition on the land.
- **Land** includes water and air on, above or under land.”

These definitions are consistent with those in the *Energy Pipelines Act*, *Waste Management and Pollution Control Act*, *Water Act*, and *Mining Management Act*.

The NT Environment Protection Authority (NT EPA) suggested that the definition of “environment” in the *Environment Assessment Act* requires redrafting to reflect a contemporary understanding and use of the term. To specify all the matters embraced by the “environment” term in the title of the Act would be cumbersome. Consistent with the Commonwealth’s *Environment Protection and Biodiversity Conservation Act* (EPBC Act) Review, “environment” might better be defined to include social, economic and cultural conditions in accordance with ecologically sustainable development principles. Sacred sites, heritage and other matters arise

under separate Acts, so when the Terms of Reference for an Environmental Impact Statement (EIS) are drafted, references to them would be included as necessary

Hydraulic Fracturing is the process used in shale gas extraction of injecting liquid at high pressure into subterranean rocks, boreholes etc to force open existing fissures and extract oil or gas. CSIRO's explanation of this process is reproduced in Chapter Three of this Report.⁵

Hydrocarbon is a compound of hydrogen and carbon, such as any of those which are the chief components of petroleum and natural gas.⁶

Risk is a situation involving exposure to danger or the effect of uncertainty on objectives. Risk is often characterised by reference to potential events and consequences, or in a combination of these.⁷

Environmental Impact is defined, for the purpose of this Inquiry, as per the *environmental harm* and *environmental nuisance* definition from the *Petroleum Act*. The USA EPA defines an environmental impact as any change to the environment, whether adverse or beneficial, resulting from a facility's activities, products or services.

Mitigation is the action of reducing the severity, seriousness or painfulness of something⁸ - in this context, generally applied to risk.

Geology is the science which deals with the physical structure and substance of the earth, their history, and the processes which act on them.⁹

Hydrogeology is the branch of geology concerned with the distribution and movement of ground water in the soil and rocks of the earth's crust.

Hydrology is the branch of science concerned with the properties of the earth's water, and especially its movement in relation to land.¹⁰

Rehabilitation is to return something (especially a building or environmental feature) to its former condition.¹¹

Risked recoverable is the estimated proportion of prospective resources that may be technologically and economically feasible to extract.

⁵ <http://www.oxforddictionaries.com/definition/english/fracking>

⁶ http://www.oxforddictionaries.com/definition/english/hydrocarbon#hydrocarbon__3

⁷ <http://www.oxforddictionaries.com/definition/english/risk>

⁸ <http://www.oxforddictionaries.com/definition/english/mitigation>

⁹ <http://www.oxforddictionaries.com/definition/english/geology>

¹⁰ <http://www.oxforddictionaries.com/definition/english/hydrology>

¹¹ http://www.oxforddictionaries.com/definition/english/rehabilitate?q=Rehabilitation#rehabilitate__11

1.1.4 Key Measurement Acronyms

Meaning	
tcf	trillion cubic feet which is commonly used to measure the volume of natural gas. To provide some perspective and comparison, CSIRO estimates that one tcf is approximately equivalent to Australia's annual domestic gas usage.
tcm	trillion cubic metres, another common measure of natural gas volume
bcm	billion cubic metres
ML	megalitre (one million litres). An Olympic swimming pool holds about 2.5 megalitres.
GL	gigalitre. 1,000 ML, which is 1,000,000,000 litres.
M_L	local magnitude, a measure of the strength of earthquakes (the Richter scale). Only seismic events with an $M_L > 2$ are likely to be felt by people, and an $M_L > 4$ cause any surface damage

1.2 Context - International, National, Territory

In considering the shale gas industry and its potential in the NT, it is useful to consider the national and global context.

Dialogue at a national level should be instigated to ensure the opportunities and concerns are addressed collectively (ACOLA, 2013, p26). It is not just a “local issue” as the cumulative effects and benefits cross jurisdictional borders. This sense was reflected when industry members talked about the need for a more homogenous approach to regulation and practices as the industry develops.

In its submission to the Productivity Commission's Inquiry into non-financial barriers to Mineral and Energy Resource Exploration in March 2013, APPEA noted that regulatory complexity, duplication and uncertainty particularly in relation to CSG in NSW and Queensland has increased, with duplication between federal and state agencies.¹²

1.2.1 International context

The International Energy Agency (IEA) predicts that global annual gas demand (conventional and unconventional) will increase to 5.1tcm by 2035, representing 25% of the total energy mix (2011, p13). Unconventional gas is forecast to account for more than 40% of this global production increase, with growth mainly in Australia, China and North America (IEA, 2011, p13). The type and style of energy

¹² http://www.pc.gov.au/_data/assets/pdf_file/0018/122517/sub022-resource-exploration.pdf

infrastructure required will be affected by change in the energy mix, with investment in gas supply infrastructure estimated to be in the order of US \$8 trillion to support the demand and supply levels predicted (IEA, 2011, p13).

Production of onshore unconventional gas has increased in recent years as new technologies and techniques, combined with improved scientific understanding, have made shale gas commercially viable. The USA Energy Information Administration estimates the total volume of technically recoverable shale gas globally is 6,622 tcf with the most significant recoverable reserves in China (1,275tcf), USA (862tcf), Argentina (774 tcf), Mexico (681tcf), South Africa (485tcf) and Australia (396tcf) (EIA, 2011, p1-5).

The USA has seen a rapid increase in shale gas production: from 21bcm in 2005 to 141bcm in 2010 (IEA, 2012, p102). As the leading commercial producer of shale gas, the USA now has a growing export market as well as a secure domestic energy supply for the immediate future.

While China has the most significant shale resources and is pursuing evaluation programs, shale gas may be more difficult and expensive to exploit due to the region's geology. At the end of 2011 the Chinese Government had "ambitious plans" to boost shale gas production to 6.5bcm in 2015, increasing to more than 60bcm in 2020. Although China may become one of the world's largest producers, it will still need to import about half of its energy needs by 2035 (IEA, 2011, pp113-114).

There is a vast difference between jurisdictional responses to hydraulic fracturing, ranging from moratoriums through to an ongoing and rapid increase in support for growth of the unconventional gas industry. During the course of the Inquiry, some Governments changed their policy position on hydraulic fracturing: both France and Germany have moved towards lifting moratoriums, while the Nova Scotia Government unexpectedly imposed a moratorium.

Hydraulic fracturing, and its potential risks to the environment, is receiving significant public attention as different jurisdictions seek scientific understanding of the process, consider whether onshore gas exploitation is viable and if so, how they may monitor and regulate the industry.

Attached to this, is the debate around gas versus coal and its contribution to greenhouse gas emissions from a whole of production lifecycle perspective. When used in place of other fossil fuels, natural gas reduces emissions of greenhouse gasses and local pollutants (IEA, 2011, p81).

Increasingly, pollution policies and climate change considerations are influencing fuel and technology selection, and natural gas is becoming the preferred fuel in end-use sectors and power generation (IEA, 2011, p85). Even so, some argue that investing in unconventional gas, often referred to as a “bridging fuel”, will divert investment in developing cleaner, renewable energy sources. And some activists are opposed to fossil fuels *per se*.

1.2.3 National context

There is little doubt that within Australia there is growing demand for gas supplies, both for domestic use and as an export opportunity to meet global demand for which the NT is geographically well-positioned. There is significant prospect for unconventional gas production: it is likely to be plentiful, to become an integral part of the nation’s energy mix, with the potential to contribute to economic and regional development and growth.

The Inquiry is mindful, however, that future demand for gas within Australia, particularly within the power generation and industrial sectors, could be affected by policy changes relating to carbon trading and greenhouse gas targets, as well as domestic gas prices.

Discussion about challenges that the energy industry faces is also occurring at the national policy level (see for example, the Business Council of Australia’s (BCA) November 2014 Report entitled “Australia’s Energy Advantage”). In addressing natural gas resources, the BCA called for Governments to prioritise gas resource development by removing inappropriate regulatory barriers, expediting projects and improving transparency of information to assist in managing supply uncertainty. They also argued that higher production costs (compared to other countries), linking the domestic and international markets, community concerns and technical uncertainty are all contributing to market uncertainty.

The technology to develop unconventional gas further is available in Australia and the demand for low emission gas has grown significantly in the pursuit of long-term energy security and to decrease Australia’s pollution and greenhouse emissions. The onshore gas industry is developing in Australia, with most current activity focused on Coal Seam Gas extraction.

The first vertical wells specifically targeting shale gas were drilled in the Cooper Basin in early 2011 where exploration is now underway and, to a lesser extent, in other promising areas (IEA, 2012, p132).

The significant estimated onshore gas resources are predicted to be economically viable for production. Most of Australia's shale gas occurs in deep basins spanning vast areas of the NT, remote Queensland, SA and WA.

ACOLA (2013) cautions that any national resource estimates have “very large associated uncertainties”, but estimates Australia's total hydrocarbon deposits (conventional and unconventional) at as much as 819 tcf (p48). As noted earlier, the US Energy Information Administration estimates “technically recoverable” shale gas resources in Australia at 396 tcf. To provide some perspective and comparison, one tcf equates to Australia's annual domestic gas usage.¹³

It should be noted that commercial shale gas production in the very near future is not likely due to logistical difficulties and the high costs associated with labour and hydraulic fracturing (IEA, 2012, p132). This sentiment was echoed by some organisations during interviews with the Inquiry who suggested that the industry will take some years to develop, on the assumption that exploration proves viable resources are available.

Challenges to the industry such as a ready workforce, existing infrastructure and pipe-line connections are raised in numerous documents, including the Australian Government's Green Paper which was released in September 2014 to inform development of the Energy White Paper. These issues are also discussed throughout this Report. The Green Paper also discusses gas supply and market development, including an industry development strategy for unconventional gas. Other aspects of the paper, within the context of what this Inquiry has considered, were regulatory frameworks, the implication of duplication and suggested approaches to address this challenge.

On 1 October this year, the Commonwealth Parliament Senate announced its intention to conduct an Inquiry into the Queensland Government, including a review of all Coal Seam Gas applications. A weather eye should be kept on this Inquiry, in case its outcomes impact on NT arrangements.

The Federal Government has also established advisory groups or committees to advise on national policy and oversee onshore gas activities, with a particular focus on Coal Seam Gas at this time. For example, the Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development, established under the EPBC Act, provides advice to the Federal Minister on the impact that Coal Seam Gas and large coal mine developments may have on water resources.

¹³ <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/Shale-gas-potential.aspx>

Among other activities, the Committee undertakes bio-regional assessments about ground water and surface water and can also provide independent, expert, scientific advice to State/Territory Governments at their request.

Each jurisdiction adopts a unique approach to its legislative and regulatory framework, and the associated policies. As the industry is in its infancy and has a tendency to attract controversy, Australian governments are navigating the current issues with a range of impacts on the industry. At the time of writing this Report, the following was observed.

New South Wales

CSG activity (exploration and production) and the issue of securing long-term gas supply for the domestic market has attracted significant attention in NSW, leading to a range of measures to manage CSG development and earlier this month, the release of the NSW Government's Gas Plan. The Plan forms part of the Government's response to the Chief Scientist and Engineer's Independent Review into Hydraulic Fracturing with the aim of improving understanding of the industry and to identify gaps in the management of risks with a particular focus on human health, the environment and water catchments.¹⁴ The new Gas Plan will see a significant reduction in the percentage of land made available for exploration purposes.

Chapter Three deals with the Chief Scientist and Engineer's Report, noting the NSW Government's acceptance and support for all her recommendations.

The Gas Plan articulates how NSW will deliver best practice regulation while increasing gas supplies and putting downward pressure on gas prices for the State's households and businesses. The Plan has five priority pathways to reset NSW's approach to gas:

- better science and information to deliver world best practice;
- pause, reset and recommence: gas exploration on our terms;
- strong and certain regulation;
- sharing the benefits; and
- securing NSW gas supply needs.

Actions include cancellation of all current exploration applications, and strict standards will have to be met before resumption.

¹⁴ http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0004/520393/tough-new-rules-for-coal-seam-gas-activity.pdf

The NSW Environment Protection Authority will be the lead regulator for compliance and enforcement of conditions, including those set in titles and those required in work/activity approvals by the Office of Coal Seam Gas. A Community Benefits Fund will also be established.

Measures that have been implemented in recent years have included:

- March 2012 - the use of BTEX chemical compounds (benzene, toluene, ethylbenzene and xylene) in all drilling and hydraulic fracturing activities were banned;
- September 2012 - a *Code of Practice for Coal Seam Gas Fracture Stimulation Activities* and a *Code of Practice for Coal Seam Gas Well Integrity (the Codes)* were introduced which provide standards for hydraulic fracturing and petroleum well integrity. These codes are applied through permit conditions;
- also in 2012, the Land and Water Commissioner was appointed and the NSW *Strategic Regional Land Use Policy* (both discussed in further detail in Chapter Six) and *Aquifer Interference Policy* were introduced, as was the requirement for most CSG development to hold an Environment Protection Licence from the NSW Environment Protection Authority;
- February 2013 - the NSW Office of Coal Seam Gas was established to administer all petroleum related matters, including titles, activity approvals and the associated environmental assessments, and monitoring and auditing operators' compliance with relevant legislation, including work health and safety;
- March 2014 - the NSW Government announced a freeze on new Petroleum Exploration Licence Applications, which was subsequently extended until 25 September 2015. During this freeze, the Office of Coal Seam Gas will be developing a more comprehensive petroleum title application process;
- April 2014 - the NSW Government commissioned Mr Bret Walker SC to undertake an independent review of the land access arbitration processes relating to exploration;
- September 2014 - the Chief Scientist and Engineer produced the Final Report of the Independent Review of Coal Seam Gas Activities in NSW; and
- November 2014 - the NSW Government released its Gas Plan.

Queensland

CSG production is under way in various regional areas, with hydraulic fracturing as part of the extraction process. To support commercialisation of the resources, significant investments have been made in constructing liquefied natural gas (LNG)

facilities at Gladstone and the associated pipelines to connect gas fields to the new facilities. CSG-LNG compliance and enforcement is managed through local, Queensland and Australian Government agencies. To manage compliance and enforcement, the Queensland Government established the CSG Compliance Unit (formerly the LNG Enforcement Unit) which includes

*“multi-disciplinary industry and environmental staff from across government, including environmental and ground water experts, petroleum and gas safety specialists and staff specialising in land access issues”.*¹⁵

The Inquiry observed that levels of community acceptance vary in different parts of the State and there has been significant public commentary and activity against the industry in some areas. As part of their commitment to give the community a stronger voice in the industry’s development, the Government set up the GasFields Commission, a statutory body to manage the coexistence of rural land holders, communities and the CSG industry.

South Australia

While the unconventional gas industry has attracted political and public attention, particularly in wine growing areas in the South East corner, the Government has been highly supportive of the industry.

In 2010, the Government established the Roundtable for Unconventional Gas Projects in South Australia, which in December 2012 had a membership of 212 from peak bodies, industry, media, the community, universities and Government (DMITRE, 2012, p.6). The Group’s work focused on informing how unconventional gas development could be undertaken sustainably and efficiently, taking into account the environmental, social and economic impacts and benefits, and was critical in developing the *SA Roadmap for Unconventional Gas Projects* which was released in 2012.

In recent weeks, the Opposition has called for a moratorium on gas exploration and production in the State.

The SA regulatory framework was often referred to throughout consultations as the strongest in Australia. The Cooper Basin features advanced approaches to unconventional gas projects with significant potential for economic development which could extend production for decades.

¹⁵ <http://www.business.qld.gov.au/industry/csg-lng-industry/regulatory-framework-csg-lng/enforcement-compliance>.

Fracture stimulation has been used successfully for many years in the Cooper Basin to enhance oil and gas production. In the last 45 years, 716 wells had been fracture stimulated (includes Geodynamic's geothermal wells) with 1681 stages.¹⁶

Unconventional gas plays have also been identified in other basins with exploration underway. These include shale gas, basin-centred gas (pervasive tight gas) and deep coal seam gas. Following on from ten vertical wells to test unconventional gas plays in 2012, 15 wells were drilled during 2013. In December 2012, Beach Energy began drilling Holdfast, the first dedicated horizontal well to test shale gas deliverability in the State.

Tasmania

While Tasmania has no history of hydrocarbon production or hydraulic fracturing, one explorer has recently started looking at the potential of areas in southern Tasmania to host oil and gas within an unconventional reservoir (the Woody Island Siltstone). Tasmania is unlikely to experience significant hydraulic fracturing due to geological constraints. A moratorium on hydraulic fracturing is currently in place until March 2015 and an issues paper was recently released for public comment.¹⁷

Victoria

Exploration for unconventional gas started in the early 2000s with tight gas discovered in the Gippsland region. As a result of an Inquiry, in May 2012 the Parliament's Economic Development and Infrastructure Committee made 25 recommendations on a wide range of matters including establishing processes to enable community engagement for Coal Seam Gas exploration, implementation of the National Harmonised Framework and outcome focused work approvals to manage risks better.

Approvals for new onshore gas exploration licences, hydraulic fracturing and onshore gas exploration drilling are currently on hold. Following release of the Gas Market Taskforce Report in October 2013, the Government extended the moratorium while it conducts water studies and seeks community views. This information is to be reported in July 2015 to support decision making by the incoming Government.¹⁸

¹⁶ Email from South Australian Department of State Development to the Inquiry, 24 November 2014

¹⁷ [http://dpipwe.tas.gov.au/about-the-department/review-of-hydraulic-fracturing-\(fracking\)-in-tasmania](http://dpipwe.tas.gov.au/about-the-department/review-of-hydraulic-fracturing-(fracking)-in-tasmania)

¹⁸ <http://www.parliament.vic.gov.au/publications/research-papers/8927-unconventional-gas-coal-seam-gas-shale-gas-and-tight-gas>

Western Australia

While exploration of significant potential onshore tight and shale gas resources has been undertaken in WA for some years, and there is an active conventional oil and gas industry, the onshore unconventional gas industry is in the early stages of exploration and evaluation.

Most recently, Buru Energy's plans to develop operations in the Kimberley has attracted significant attention as they seek community and traditional owner support. Exploration and proof of concept programs for tight and shale gas by AWE and Norwest continues in the mid-west.

A number of state government agencies contribute to the current regulatory framework including:

- Agriculture and Food;
- Environment Regulation;
- Health, Parks and Wildlife;
- Mines and Petroleum;
- State Development, Water; and
- the Environmental Protection Authority.

The Parliamentary Committee on Environment and Public Affairs has been conducting an Inquiry into the Implications of Hydraulic Fracturing for Unconventional Gas since August 2013. The Inquiry's Terms of Reference are:

- how hydraulic fracturing may impact on current and future uses of land;
- the regulation of chemicals used in the hydraulic fracturing process;
- the use of ground water in the hydraulic fracturing process and the potential for recycling of ground water; and
- the reclamation (rehabilitation) of land that has been hydraulically fractured.

It remains unclear when the Inquiry will conclude its work, however it is expected to be finalised in mid 2015.

1.2.3 The Northern Territory (NT) context

The NT's conventional oil and gas industry is well established and has grown significantly in recent years. The value proposition is dominated by LNG production from Darwin and this will increase when INPEX's Icythys LNG project comes on line. Most of this activity is based on conventional, offshore operations with current major projects focused on the Bonaparte Basin. Onshore, conventional gas has been extracted in the Amadeus Basin, with the first hydraulic fracturing

taking place in 1967 and over 30 vertical wells receiving hydraulic fracturing treatment since that time.

The offshore petroleum industry is regulated by the National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA).

Since 2012, NOPSEMA has been responsible for regulating offshore operations within Commonwealth waters, particularly health and safety, well integrity and environmental management. The Authority is also responsible for designated coastal areas conferred by the relevant State/Territory.

At December 2013, there were three production licences where hydrocarbons have been produced since the early 1980s, four retention licences and 55 active onshore petroleum exploration permits. Expenditure for onshore petroleum exploration activities during 2013 was about \$27million (NT Government, 2013, pp2-3).

Onshore unconventional shale gas exploration is a relatively new industry in the NT. The first wells targeted at shale gas which involved horizontal as well as vertical fracking were undertaken in 2011. The APPEA submission (p11) estimates the NT's shale gas resources at 56tcf of risked recoverable and 262tcf of potential resources.

Interest in the Amadeus, Georgina and McArthur basins is growing, along with some smaller basins, however issues associated with the availability of existing infrastructure and access to the gas market are important considerations. These issues were also raised in the ACOLA Report (2013, p22) which considers the limited existing pipeline and road networks will have a significant impact on development of shale gas in remote areas.

The Inquiry notes that the NT Government's Discussion Draft Economic Development Strategy, released in October 2014, identifies infrastructure, along with land and water access, as essential enablers to future development. That Strategy also highlights energy resources as a major opportunity for driving future development in the NT.

The current legislative framework for the onshore shale gas industry in the NT is outlined in the following section.

The NT is approximately 1,349,000km² in size. Most land is owned by the Crown (with almost 540,000km under lease - primarily pastoral) or declared Aboriginal Land (380,000km² being freehold and 11,000km² being leasehold). Some

44,000km² is declared nature conservation reserves. The remainder includes defence land, other crown land and freehold land. (CSIRO *et al*, 2013, p.3)

Some 90% of the NT has exploration permits currently granted over it, but Department of Mines and Energy (DME) has recently started recalling permits and operators have to demonstrate their activity/intention over the permit area and potentially hand some back. Given most of the NT is either freehold Aboriginal land or pastoral lease, the issue of land access and engagement with land owners is a crucial factor for all industries operating throughout regional and remote areas.

The high Indigenous population in the NT is also a consideration for the industry and Government alike, particularly with respect to how they engage with traditional owners who do not have English as a first language and how they might provide genuine opportunities for locals via employment and other benefits. In gaining approval to explore on Aboriginal land, operators must also consider the cultural and spiritual connection to land and the powerful role that will play in decision making.

These factors are discussed in more detail throughout the Report.

1.2.4 NT Onshore Petroleum Exploration and Production Process

The *Northern Territory Petroleum Act 2011* (the Act) and the *Schedule of Onshore Petroleum Exploration and Production Requirements 2012* (the Schedule) are the principal legislation that address petroleum tenure, exploration and production activity in the NT. The Act is the legal framework which ensures companies undertake effective exploration for petroleum and any benefits of petroleum production and development is returned to the NT.

The current regulatory and compliance processes in place have many stages and can be complex, particularly to observers outside the industry. This summary outlines, in plain terms, the current processes which should be complied with in the NT and describes the type of activities associated with each stage. It also touches on some of the specific requirements while acknowledging that it may not reflect the full detail and intricacies of some stages. Regulatory processes are analysed in more detail in Chapter Five.

In discussing the process, the Inquiry also notes that the onshore petroleum industry is in its infancy in the NT, with only a handful of onshore, conventional production licenses in place and notes that DME is currently reviewing the Act.

1.2.4(a) Securing Land Tenure for Exploration

Operators are required to secure land tenure which is provided through an Exploration Permit (permit). In applying for a permit, operators must outline their five year work program, taking into account all relevant information such as environmental protection, heritage and cultural issues which could add requirements or conditions on the permit. Consultation with third parties who have a recognized interest in or ownership of the land included in the permit area must be undertaken and their permission to access the land for exploration secured. This includes following the legislated processes associated with Aboriginal land (including sacred site clearances) and negotiating with holders of pastoral leases.

In reviewing the permit application, the Minister must consider if the applicant has the technical expertise and financial capacity to undertake the work and past performance.

If an operator's application meets all the requirements and is approved, an exploration permit is issued, which gives the holder exclusive right to explore for hydrocarbons and undertake activities, such as seismic surveys and drilling, within the permit area in accordance with the Act, the Schedule and the permit conditions.

The legislation allows for multiple applications over the same vacant area which leads to a competitive application regime. The government also has the ability to “cancel” permits where the operator is not actively undertaking the approved exploration works program.

1.2.4(b) Exploration Phase

Having secured the permit, the operator is able to undertake exploration activities as per the approved work program and any additional conditions of the permit. The exploration phase enables the operator to progressively build their understanding of the area so they can make informed decisions about whether there is a gas reserve that is suitable for production.

This process typically starts with a review of available data sets, field mapping and geological and geophysical surveys. From that, stratigraphic drilling and 2D seismic surveys give the operator more data and information required to identify where to drill an exploration well. The results of these surveys are provided to DME to contribute to the overall knowledge of the area for use by the NTG and future explorers.

Depending on the results of the exploration wells, the explorer may decide to undertake hydraulic fracturing tests on the well to enhance permeability and provide data for the fracture propagation model. It should be noted that this fracturing cannot be undertaken until operational approval is received from DME.

If these results prove promising, the operator may drill horizontally and undertake main hydraulic fracturing.

Even though the operator's work plan was approved as part of their exploration permit, they are required to seek further operational approvals from DME before they undertake activities including seismic surveys, drilling a well, hydraulic fracturing and well suspension or abandonment. This means that operators seek numerous operational approvals from DME throughout the exploration process. These approvals need to address a range of matters including: environmental impacts and rehabilitation, evidence of stakeholder consultations, MSDS for chemicals, baseline water study, waste management, biodiversity management, traffic management, dust management, weed management, erosion and sediment control, bushfire management, emergency response, safety management, adequate level of insurance and sufficient level of environment rehabilitation security. The environment management plan is assessed in line with the process outlined in 1.2.4(f), while a further description of an operational approval is included in 1.2.4(g).

Monitoring is also required during exploration activities and operators are required to submit an annual exploration report to DME highlighting actual activity against the approved work program. Further information about monitoring and reporting is included in part 1.2.4(h). Any alterations to an approved work program, including variations and suspension of the work program, must be approved by DME.

Based on the information gained through exploration, the operator will decide whether production is viable and determine the land area required for production purposes.

1.2.4(c) Securing a Production Licence

If the operator has defined an oil or gas resource and plan to move forward to production they need to apply for a Production Licence, which will typically be over an area smaller than the initial exploration permit. The application will be assessed on the proposed field development relative to the total area applied for, the geological rationale and the operator's financial and technical ability to undertake

the planned work program. The operator must also abide by any restrictions or special provisions that may apply to national parks, reserves and Aboriginal land.

The application for a production licence must include a range of documents, plans and strategies which detail the intended petroleum development and production activities, assess the associated risks and demonstrate how they will be mitigated or managed. The documents include the reservoir management plan and the field development plan (FDP) which details the gas reserve and the development and production management plans. Other documents include environment management plan (which includes a rehabilitation plan that details the removal of production facilities from site and the restoration of the land, either back to its natural state or put to new use), emergency response plan, oil spill contingency plan, safety management plan, evidence of appropriate insurance coverage and other supporting documents as requested by DME specific to the application.

A security bond is lodged prior to grant of a production licence as required under the Act. The security is held by NTG for the life of the production licence.

1.2.4(d) Drilling and Production Phase

The Production Licence provides exclusive access to the land for the purpose of production; however project approvals for further development activities must still be sought. As such operators will make numerous applications to DME over the production period.

Site preparation for drilling and production is undertaken which could include site clearing and establishing access roads, site offices and storage facilities.

Once drilling starts activity on site becomes much more intense with operations being carried out up to 24 hours a day. Drilling operations can take up to several months depending on the depth of the well and the surrounding geology. The well drilling process includes testing the well integrity to allow a safe connection to deep shale reservoirs and inserting multiple layers of steel and cement, which secure the gas and hydraulic fracturing fluids inside the well to minimise the possibility of leakage into water aquifers. All drilling liquids and mud is stored either in contained units or in geomembrane or similarly lined HDPE lined sumps on site before being disposed of in the correct manner.

Once a well is completed and shown to produce an economic flow of gas it is connected to a pipeline which carries gas to the processing plant. In a large gas

field, satellite facilities may collect gas from a network of wells, and may remove some water and boost compression before gas is piped to a larger processing plant.

During their lifetime wells may be reworked or refractured to improve production, and any of these activities entails a detailed approval process.

There are strict monitoring and reporting requirements during the production phase which operators adhere to which are explained in further detail in 1.2.4(h).

1.2.4(e) End of Production Phase and Site Rehabilitation

Once a field reaches the end of its life and any production is no longer economically viable, the field and production facilities have to be decommissioned. When this occurs, all the wells will have to be plugged and abandoned. The wells are plugged with cement to prevent hydrocarbons from flowing into aquifers and to the surface. The operator must gain operational approval to decommission the production facility and plug and abandon all the wells. The environment must be returned to its natural state or put to a new use with any environment impact risks reduced to as low as reasonably practicable. Environmental rehabilitation is then undertaken with ongoing monitoring. Operators must submit a final close out report which details the environmental rehabilitation work completed. Once the rehabilitation has been concluded and environmental standards have been met the security deposit is returned to the operator.

1.2.4(f) Environment Plans and Environment Impact Assessments

As highlighted, there are numerous points in the process where an environment plan (EP) is required.

The EP must outline appropriate compliance and management procedures which allow for ongoing project monitoring and reporting.

The EP is assessed by DME in conjunction with the work plan. DME refers the EP to the EPA for assessment, consideration and comment, and other government agencies if considered necessary.

Under the *Environmental Assessment Act*, the EPA has the authority to issue the EP to other agencies and stakeholders through its “Notice of Intent (NOI)” process if there is reason to believe that there may be significant environmental risk as a result of the proposed work program. All comments or concerns received by EPA through the NOI process are provided to DME and are referred back to the operator to be addressed as part of the assessment process. After the NOI process, if the NT EPA’s

assessment shows that there may be significant environmental risk as a result of the proposed work program, an EIS may be required from the operator under the *Environment Assessment Act*.

Operators are also responsible for determining if a self-referral to the Commonwealth Government for assessment is required under the EPBC Act

As part of the EP assessment for a work program or an activity, an Environmental Rehabilitation Security Bond is calculated and paid by the operator to NTG. This bond is held until the proposed activity or work program has been completed and sufficient level of rehabilitation has been conducted. The bond is then refunded to the operator after submission of the final rehabilitation close-out report. The report has to be assessed by DME and deemed as acceptable before the bond is paid back to the operator.

Once activities have been approved, the operator must provide an EP summary which is uploaded to the DME website.

1.2.4(g) Operational Approvals

Operational approvals are required throughout the project each time an operator wants to undertake certain activities that the project approval does not cover. The types of activities which require an operational approval include seismic surveys, any drilling, side tracking a well, well suspension, well abandonment, well completion, flow testing and hydraulic fracture stimulation. Each operational approval requires a separate EP.

Security bonds are held for each activity. The operator uses an NTG calculator to propose the value of the security bond based on the specific activities they are undertaking and their impact and submits this proposed figure with the application. This is then negotiated between the NTG and operator.

1.2.4(h) Compliance Monitoring and Reporting Requirements

Throughout the exploration, production and rehabilitation phases, there are ongoing monitoring and reporting requirements as specified in the Schedule and implementation plan in the EP. Different activities require different levels of reporting: daily reports are required when drilling is being undertaken, weekly and monthly operational reports provide updates on well testing, production data and field and well activities, and annual reports are required against approved work plans. Reports are audited by DME and onsite inspections are also conducted periodically.

Monitoring is required throughout exploration and production, and some activities attract additional monitoring requirements.

In accordance with the Schedule, operators are legally required to report a range of incidents to DME including environmental incidents, property damage, emergencies and hazardous events. DME or third party inspectors have the ability to carry out operational and environmental audits.

At the end of each exploration activity or project, final data sets must be submitted which are reviewed and if accepted, the activity or project is closed out.

1.2.5 NT Legislation Relevant to Industry Regulation

The NT Environmental Defenders Office 31 October 2014 submission proposes a best practice regulatory framework for the hydraulic fracturing operations, including some important case studies. This submission will be particularly valuable in working through what has to be done to create an improved regulatory framework in the NT.

It is noteworthy and commendable that the DME is reviewing the *Petroleum Act* in parallel with the Hydraulic Fracturing Inquiry, including developing regulations to address environmental management.

DME reported that they are reviewing associated legislation, using Queensland, South Australia and Western Australia as bench marks for identifying best practice. Findings of the Hunter Report (2012) are also being implemented during this process and will contribute to creating a stronger regulatory framework.

Strengthening the regulatory framework and ensuring the capacity of regulators was a critical factor raised consistently during consultations. It was generally considered that the current regulatory regime in the NT is not “ideal”.

Participants pointed the Inquiry to elements of the regulatory frameworks in Queensland, South Australia and Western Australia, as well as some North American jurisdictions, as being more appropriate.

The Inquiry believes that the DME work is a necessary, but not sufficient, contribution to the ideal of a regulatory framework that sets the standard for best practice: a central theme that is returned to throughout the Report and in the recommendations.

Results are not yet to hand for the NT exploratory drilling programs so whether there are commercial quantities of shale gas that can be exploited is unknown.

In the event that there are exploitable opportunities, then it will take some years to turn them into production outcomes. This timing is important for a number of reasons. First, how will the production get to market?

Second, the delay from discovery to production provides the window to put in place a robust regulatory regime aimed at setting the standard for best practice.

Recommendation

The Inquiry recommends that a Cabinet Sub-Committee be formed, chaired by the Deputy Chief Minister and comprising the Ministers whose portfolios cover Lands, Planning and the Environment; Land Resource Management; Mines and Energy; and Primary Industry and Fisheries to oversee the work required for the NT to set the standard for a best practice regulatory regime.

The Cabinet Sub-Committee would be served by a Taskforce consisting of the related officials with the Secretariat provided by the DCM which would also provide the Chair at Executive Director level.

This work should be initiated as soon as possible so that it is completed by the end of the first quarter in 2015. Most of what is required already exists, but it scattered among Departments and the gaps that have to be filled have been identified.

The Inquiry believes that this is the way to get real reform, real debate, real discussion and real understanding of the issues. It's at the political level that the balance can be struck between promoting Shale Gas development, setting the environmental management parameters, facilitating land access and fostering the NT's economic development.

In undertaking this task, the Cabinet Sub-Committee and Taskforce would take into account the guidance and findings of this Report, the 2013 COAG Standing Council on Energy Resources paper titled "The National Harmonised Regulatory Framework for Natural Gas from Coal Seams", as well as approaches and practices in other jurisdictions, such as South Australia.

Chapter Two - What the Inquiry heard

The Inquiry sought to hear from people involved in or affected by the unconventional gas industry and/or interested members of the NT community.

The communication exchange on a broad range of aspects was particularly pleasing as all participants expressed their thoughts and ideas in a respectful manner in accordance with ACOLA's finding that open, honest and responsible dialogue, which meets the needs and concerns of different groups and draws on information from independent credible sources, is vital in exploring this issue (ACOLA, 2013, p26).

The International Energy Agency (2012) observes;

“there is a critical link between the way the government and industry respond to these social and environmental challenges and the prospects for unconventional gas production” (p9).

The range of submissions and information provided to the Inquiry aligns with ACOLA's recognition that complex issues, such as unconventional gas extraction, attracts a “broad diversity of stakeholders with different values, interests and levels of knowledge” (ACOLA, 2013, p158).

Submissions to the Inquiry were invaluable to:

- bringing forward a broad range of information and perspectives;
- identifying areas of agreement, contention and concern by industry, environmental groups, individuals and governments;
- clearly understanding the community's concerns;
- discussing contemporary industry practices and how they apply in the NT context, particularly how environmental requirements can be met and the challenges associated with this; and
- enabling misinformation, “myth” and misunderstanding to be identified and the evidence and information required to address that.

The Inquiry appreciated hearing the views of so many individuals and organisations. While it has not been possible to reference or quote each contribution throughout the Report, all submissions (oral or written) were considered and the Inquiry is confident that it has captured the essential issues. Written submissions will remain on the website as part of the public record. The significant effort that

individuals and organisations invested to ensure their participation, responding to direct requests for information and facilitating research efforts and discussions is acknowledged and appreciated.

2.1 Community Consultations

On commencement of the Inquiry, public submissions were sought enabling interested citizens, as well as organisations and industry groups, to offer their thoughts. There was no set format for submissions; people were simply asked to respond to the Terms of Reference. The formal submission period closed on 30 June 2014, although further information continued to be accepted for the duration of the Inquiry.

Of the 262 submissions received, 122 were campaign style submissions with three such generic letters identified. The remaining 140 were “unique” submissions from individuals and various organisations and some were quite substantial in presenting their research and supporting materials.

In addition to the written submissions, community members were also able to present questions and thoughts to the Commissioner at a series of open forums in Alice Springs, Katherine and Darwin. Around 150 people attended the three community meetings, and most of them presented their thoughts and questions.

An analysis of the terms used and topics raised was undertaken, and while some do not directly relate to the Inquiry’s Terms of Reference, the community’s concerns were properly captured. This understanding, which provided important insights for the Inquiry, will also be of significant benefit to the NT Government and industry as it documents the community issues that need to be addressed through further engagement.

2.2 Community Themes and Issues

The top 15 topics raised by the community through written submissions or at public meetings were:

Table 2-1: Top 15 Community Themes and Issues

	Topic	Percentage of speakers/submissions	Related Term of Reference (TOR)
1	Water Contamination	55%	3, 6, 7.1, 7.2, 7.3, 7.5
2	Social, Cultural and Environmental Impacts	53%	While environmental impacts broadly covers the full TOR for the Inquiry, the economic, social, cultural and heritage implications are not specified - refer to discussion notes below
3	Water Use	38%	3, 7.1, 7.2, 7.3, 7.5
4	Rivers and Aquifers	38%	3, 6, 7.1, 7.2, 7.3, 7.5
5	Health Concerns	36%	Not specified in TOR - refer to discussion notes below
6	Short Term Benefits - Financial, Jobs etc	33%	Not specified in TOR - refer to discussion notes below
7	Long Term Impacts	31%	This relates to a number of TOR's, specifically 5, 7.10, 7.11
8	Moratorium	28%	Not specified in TOR - refer to discussion notes below
9	Monitoring and Compliance	28%	7.8
10	Fugitive Emissions	26%	7.6
11	Chemical Usage	24%	7.4
12	Regulatory Regime	23%	While not specified in the TOR, the regulatory regime question is discussed and explored under the broader consideration of mitigation measures, particularly with respect to the elements listed in TOR 7
13	Water Waste Management	22%	7.5
14	Pollution	21%	7.6
15	Impacts on Future Generations	20%	Not specified in TOR

Issues associated with protecting and sustaining water supply and aquifers were the most prominent concern across all regions. Other themes attracted more attention regionally.

For example, Alice Springs had a higher focus on long term impacts, fugitive emissions, social and cultural impacts and the creation of a robust regulatory regime.

Darwin had the strongest focus on monitoring and compliance/regulatory regimes as well as water contamination, social and cultural issues, and long term impacts.

In Katherine, discussion revolved around scientific studies, health concerns and chemical use, and there was a manifest sense of discontent between pastoralists and

mining companies, particularly about inconsistent requirements associated with water use, public declarations of chemical use and land access.

The Inquiry observed a very high level of regional pride and there was a great desire to ensure longevity of their local environments and livelihoods.

The NT community issues are not dissimilar to those expressed in other jurisdictions nationally and internationally. For example, submissions to Nova Scotia's recently completed Inquiry highlighted the community's top 15 issues as being: ground water (72%); surface water (72%); ban or moratorium (46%); additives to fracturing fluids (41%); land/soil (27%); waste management (25%); effect on residents, including health (24%); transparent public consultation (21%); flora, fauna, forest and habitat (21%); air pollution (20%); livestock, crops and farming (20%); cost/benefit to the economy (19%); tourism (14%); creation of greenhouse gases (13%); and trucking (12%).¹⁹

The themes raised during consultations which relate directly to the Inquiry's Terms of Reference are addressed throughout this Report. Where additional concerns were raised, not specifically included in the Terms of Reference, they have also been considered as far as possible through the technical and academic assessments undertaken by the Inquiry.

2.3 Consultations with Organisations, including Industry and Peak Bodies

Thirty-five (35) submissions were received from environmental groups, professional associations, industry members and government agencies. All organisations were offered the opportunity to meet with the Commissioner for a more detailed discussion, respond to cross-referenced questions by other submitters and provide supporting documentation. In some instances, organisations provided further documents and information following these discussions.

Information and research provided by organisations was critical to the analysis, along with academic and desktop research. Meetings provided the opportunity for very specific aspects of the process to be explored. Various positions on shale gas extraction and hydraulic fracturing were presented and areas of agreement and common considerations emerged.

¹⁹ <http://www.novascotia.ca/nse/pollutionprevention/docs/Consultation.Hydraulic.Fracturing-What.We.Heard.pdf>.

2.4 Organisational Themes and Issues

NTG Capacity (People and Technical Skills) Required to Establish a Proper Regulatory Regime

Throughout the discussions, there was consistent recognition that a regulatory system is only as good as the regulator's skills and experience and how they apply the regime. There was a strong belief, particularly from community interest groups, that regulators need to be seen in and by the community visiting operations to undertake inspections. Discussions pointed to a perceived gradual reduction in staffing and resources supporting assessment and regulatory activities associated with environmental management, with a lack of hydrologists emphasised.

A strong Robust Balanced Regulatory Framework is Critical

A core message throughout all the interviews, also reflected by comments from individuals, was that the regulatory system needs to be stronger to find balance between protecting the environment, community expectations and industry's ability to operate effectively and efficiently.

The general sentiment that this Inquiry heard aligned in many ways with the Productivity Commission's conclusion in its report into Mineral and Energy Resource Exploration, that many stakeholders are dissatisfied with current regulatory arrangements (Productivity Commission, 2013, p2).

While industry believes the requirements discourage exploration, community groups claim they are insufficient in protecting environment, culture and land use (Productivity Commission, 2013, p2). Some operators suggested that the regulatory system needs to enable industry to progress with new improved technology which supports better environmental outcomes and professional regulators need to "keep up" with industry advancement and leading practice.

In this regard, regulators could benefit from professional networks or associations that they can tap into to keep abreast of industry advancements and how they relate to regulatory arrangements such as STRONGER²⁰ in the USA.

Given the NT's diverse climatic and environmental considerations, the regulatory framework should maximise its use of different "layers", such as the legislation, regulations and supporting guidelines (Manager's Rules which can be more tailored to different seasonal/climatic aspects).

Resolution of the regulatory framework emerged as the number one issue.

²⁰ <http://www.strongerinc.org/>

Need for Available and Transparent Baseline Data and Mapping to Inform Decision Making and Monitoring Operations

Concerns involved limited data and knowledge about much of the NT's general geology, hydrology, seismicity and hydrogeology, and more specifically in areas identified for future exploration. Information available and collected through exploration phases, but not shared and transparent was also raised.

Without appropriate and sufficient baseline data and research now, monitoring might be ineffective in the future as impacts may not be properly measured. ACOLA (2013, p29) stressed the importance of collecting baseline data and undertaking research on ground water chemistry, ecological systems, landscape changes, methane emissions and seismic activities that would enable any future impacts to be clearly identified at an early stage.

Several organisations suggested a web-based information repository to enable organisations to easily share information about aspects such as aquifers, basins, gas reserves, geology, hydrogeology and seismicity would be beneficial for everyone (including the regulators).

There was also a strong desire for a site, such as the commonly referenced USA's FracFocus which provides information about operational sites, (active/abandoned) wells, current activity, exclusion areas, chemical disclosures etc. While some of this information may be readily available, its accessibility and readability could be improved. APPEA is said to be developing a website which could meet this need. It will be important to distinguish between information that is required under legislation to be made publicly available and information that operators supply voluntarily.

General Lack of Understanding About NT Onshore Production - Gas Types, Extraction Methods and Industry Opportunities

There was an overriding awareness about the lack of understanding outside of the industry about onshore unconventional gas. Specifically, there is little understanding about the differences - or that there even is a difference - between shale gas and CSG. The high level of distrust, frustration and misinformation, combined with polarised views, makes it challenging for honest, productive communication to occur. This was expressed in various ways by organisations and representatives on all sides of the debate.

The Inquiry hopes that this Report will be an independent voice which provides balanced, factual and thorough information tailored to the audience.

High Level of Concern about Consultation Processes with Traditional Owners, Land Owners and the Community

Hand in hand with limited general understanding of the industry, is a concern about the consultation process with the community and land owners, particularly Indigenous land owners. There was acceptance that effective engagement supports informed consent and an awareness of the challenges associated with culture, language and distance/remoteness.

Other issues raised included resourcing challenges at Land Councils, the process of identifying owners and the “make up” of the engagement team to ensure balanced information is provided.

The Inquiry notes that the time and process required for engagement to gain consent to operate has been raised more generally as a challenge for commercial investment (Deloitte Touche Tohmatsu, 2013, p9). This issue would need to be considered by the Cabinet Sub-Committee recommended elsewhere in the Report, taking into account the balance of public participation, commercial certainty and land owner’s rights.

Belief that Investing in Onshore Gas Production will Delay Investment in Renewable Energy Production, and that Onshore Gas will not Contribute as Significantly to GHG Reduction

Various positions were presented to the Inquiry about the connections between greenhouse gas emissions and onshore gas, including whether growth in the industry/usage has contributed to reported reductions in GHG in some parts of the world (eg the USA) and GHG released during the extraction process.

Where discussion considered the full energy mix, it was acknowledged that gas was favourable over coal with respect to end-user generated GHG emissions.

During the Inquiry, this issue received considerable media attention due to international debate and reporting on GHG reduction targets. While there was general agreement about the importance of continuing to develop renewable energy sources, complexities included the need to compare energy sources from a “whole of production” perspective and current economic viability.

Industry needs a Social Licence to Operate

Within the NT, the community does not have a long history with onshore unconventional gas and there is a sense that the industry is being “rushed”.

Companies noted that communities, where oil and gas has played a significant role in its development and growth over many years, understand better and were more comfortable with the industry. For these communities, hydraulic fracturing and the presence of wells is an accepted fact of life.

A consistent message (again), was that industry needs to be more open with the community by communicating more with them through both legislated requirements and voluntary engagement with affected areas.

“Social licence” is addressed in considerable detail in Chapter Six.

A Balanced Approach to Gas Extraction Activity, Taking into Account Environmental Protection and Regional Impacts

While onshore gas could play a key role in the NT’s future economy, it must be able to live alongside other industries and regional aspects.

In its 2013 report “Positioning for Prosperity”, Deloitte Touche Tohmatsu identified five areas of opportunity:

- agriculture;
- energy and resources;
- infrastructure development;
- international education; and
- tourism.

Of interest, agriculture and tourism were two industries the public perceive to be “at risk” from potential negative outcomes of the onshore gas industry.

Regional strategic planning would help to capture all aspects in one place, pull together all industry development and how that relates to land use, water allocation, employment, protection of the environment, social impacts and areas of significance. Onshore gas does not have to be mutually exclusive to other industries, but the risks and potential impacts need to be managed properly and consultation with the local community is essential.

Engaging the community in developing such plans would be preferable. Opportunities that could be explored include best use of recycled water, employment and training and shared infrastructure opportunities. People were

interested in the clarification and direction such plans could provide to protect important areas and aspects of the region and ensure long term planning.

2.5 Topics Outside the Terms of Reference

Seven main issues outside the Inquiry's Terms of Reference emerged. The Terms of Reference were considered as being too narrow and "did not provide scope for full consideration of issues around hydraulic fracturing" (Submission from Public Health Association of Australia, p4). These issues are reported below to ensure the full scope of the feedback is captured accurately.

2.5.1 Social, Economic, Cultural and Heritage Impacts

As noted earlier, the term "environmental impacts" broadly addresses the full scope of the Inquiry's Terms of Reference, although social, economic, cultural and heritage impacts are not specified within them.

Cultural impacts for Indigenous Territorians, particularly those relating to preservation of sacred sites, impacts on Indigenous health, connection to country, the importance of effective consultation and information during exploration negotiations, and the role of land councils and other Indigenous organisations were raised.

The Inquiry was pleased to receive submissions from and/or meet with organisations such as the Aboriginal Areas Protection Authority Central Land Council, CentreFarm NT and the Northern Land Council, as well as hearing about issues that relate to Indigenous population, engagement and culture from a range of other stakeholders and companies.

It is not the Inquiry's purpose or intention to assess current activities as they involve and relate to cultural issues, but it is noteworthy that the NT has requirements and provisions in place, as required under legislation, for engagement and consultation with traditional land owners and communities. Effective engagement and information sharing on such complex issues, with both Indigenous audiences and the general population, continues to be a challenge which requires significant time and resources to undertake effectively.

2.5.2 Water Allocation in the NT

Water allocation is a central concern and point of contention in relation to shale gas extraction, and mining and petroleum activities more broadly. The Inquiry observed tension between industries as the mining and petroleum sectors are not subject to

the water act, which contributed to the high level of concern about potential over use of water.

Water allocation planning and licencing is administered by the Department of Land Resource Management (DLRM), including assessing aspects of ground water and surface water. DLRM provided the following overview:

There is an existing Memorandum of Understanding between the DLRM and the DME that requires approvals issued by either Department to take into the account the potential impacts on water availability and quality for all users to ensure that all demands on water are considered when issuing approvals.

“The Northern Territory Government has statutory responsibility for assessing, monitoring and allocating the Territory’s water resources under the Water Act. The water in the NT remains the property of the crown to be managed in accordance with the Water Act.

The Minister has appointed a Controller of Water Resources for the purpose of administration and regulation under the Water Act. The Controller has responsibility under the Act for issuing water extraction licences and for developing water allocation plans in declared water control districts to guide the sustainable allocation of water resources.

Water allocation planning and licensing is administered by the Department of Land Resource Management. The Water Resources Division assesses the availability of ground water resources and surface water quality and quantity, undertakes water allocation planning and administers the assessment and issuing of water extraction licences by the Controller of Water Resources.

The Water Act provides for Water Allocation Plans to be developed within Water Control Districts to establish the parameters for managing the allocation of water to users where there is competing demand for the available consumptive pool. Water Control districts are declared for areas within the Territory where there are competing demands for the resource whether for stock and domestic purposes, agriculture, industry or mining.

There are six water control districts that include the major population centres of Greater Darwin, Katherine, Tennant Creek and Alice Springs.

The Northern Territory is a party to the National Water Initiative which is an agreement to facilitate the adoption of best-practice approaches to water management nationally. The Northern Territory Water Allocation Planning

Framework (The Framework) guides both formal water allocation process in Water Control Districts and regional licensing decisions outside these districts. The Framework establishes precautionary water allocation rules when relevant science is not available. The allocation rules for water resources in the “northern zone” require at least 80 per cent of surface water flow or annual ground water recharge to be allocated for environmental and other public benefits. The remaining 20 per cent is classed as the consumptive pool available for use.

In the “arid zone”, where surface water flows and recharge are sporadic, at least 95 per cent of surface water flow must be reserved for environmental and other public benefits, and total ground water extraction over a period of 100 years is not to exceed 80 per cent of the total aquifer storage at the start of extraction.

The application of the Framework ensures that unlike southern Australia where water resources have in many instances been over allocated that the Northern Territory properly considers and accounts for all demands when making water allocation decisions and no system will be over allocated.

Outside of water control districts there is limited demand for water and the majority of water resources are used for stock and mining purposes on pastoral properties.

Water Allocation Plans have been declared for Katherine (Tindal limestone aquifer), Ti Tree and Western Davenport and are being prepared for Berry Springs, Howard East, the Great Artesian Basin, Mataranka (Tindal limestone aquifer) and the Oolloo aquifer systems. Declaration of water allocation plans establish the maximum amount available for consumption and as part of their development take into account both the current and estimated future water demands for mining and petroleum extraction.

As part of the water allocation planning process comprehensive scientific modelling of water resources establishes the consumptive pool available for use in a particular water resource which takes into account the community, environmental and supply security objectives. Management of the consumptive pool is based on an adaptive management approach that recognises natural variability in wet season recharge which ensures that minimum environmental flows are maintained.

The water allocation framework is under review as part of a broader water policy review for the Northern Territory. The development of an overarching water policy of the NT will ensure that water is properly valued and allocation and management for all uses is aligned with contemporary best practice.

The management of the Northern Territory water resources under the Water Allocation Planning Framework and through the cooperation between the Department of Land Resource Management and the Department of Mines and Energy allows for the competing demands of all users to be taken into account whilst at the same protecting our unique environment.”

There was conjecture about the future potential for the petroleum industry to be subject to the Water Act. At the Australian Water Association (AWA) NT Branch, “Water in the Bush” conference held in Darwin on 24 October 2014, the Santos representative participating in the panel discussion indicated a level of preparedness for the petroleum industry to become subject to the Water Act. Water allocation and how that may be managed into the future might also be considered by the proposed Cabinet Sub-Committee. Long term water allocation planning is highlighted as an enabling objective in the Draft NT Economic Development Strategy (NT Government, 2014, p26).

The Inquiry also noted other public comments at the AWA conference:

- the Minister highlighted that the water policy (and the subsequent 50 year water plan to be developed) will be based on good science and utilise adaptive management principles with a strong focus on monitoring to ensure the health of the water systems. Investigative drilling now underway will provide information about the NT’s water resources which can help potential investors make decisions and fast-track development.
- DLRM is currently focussing on building their knowledge base of the NT’s water resources with funding of \$2.8M over the next two years. The DLRM also encouraged cooperation and information sharing between exploration companies and DLRM about water resources, noting that while both parties may be approaching the activity from different perspectives, common information needs could be better managed.

2.5.3 Health Concerns

“Like any modern industrial technology, hydraulic fracturing and its associated activities has the potential to bring both benefits and harms to individuals, communities and populations.” (NSIRP, 2014, p308)

In line with this proposition, a range of health related concerns, both human and animal, were raised with the Inquiry and a number of instances cited where negative health impacts were claimed to have been linked to hydraulic fracturing in other countries.

A few submissions provided some detail around reported health outcomes which were attributed to onshore gas operations. It is natural that communities would be concerned and perhaps suspicious of new industries and how they might impact on a range of issues including health. While not dismissing the importance of these concerns and the need for increased understanding and monitoring of validated research into this aspect, the Inquiry was not able to identify verified studies that supported the claims. ACOLA (2013, p17) reports that there is “limited overseas data suggesting” increased health risks.

Two other recent Inquiries explored the issue of health impacts in some depth.

The NSW Chief Scientist and Engineer examined human health, concluding that while there are some reports of health effects, studies (many of which had methodological problems) were unable to find clear links between CSG and health (Professor O’Kane, 2014, p28).

The expert panel review on hydraulic fracturing in Nova Scotia also explored broad public health issues. Their Report identifies that within the extraction process there are possible exposure and impact pathways which present risks to human health and noted challenges due to an incomplete knowledge base on health impacts. Drawing on four international reports, they observed a consistent position that as hydraulic fracturing is relatively new and rapidly evolving,

“the benefits nor the harms to health and the environment are not fully known and may not be for many years or even decades” (NSIRP, 2014, p124).

Their Report placed strong emphasis on proper regulations, modelling, monitoring, management and mitigation measures. They urged health monitoring and research be undertaken to contribute to the growing global knowledge base on how this industrial practice interacts with human health (NSIRP, 2014, p.123), a finding that this Inquiry agrees with. The need for further exploration of this issue and baseline monitoring, particularly for populated areas that may have shale gas operations near-by, was shared by ACOLA (2013, p17).

The Inquiry also references a body of work undertaken by the Queensland Government which considered a risk assessment of health complaints and environmental monitoring in the Tara region where CSG is underway.

As part of this, an independent expert was commissioned to provide advice on the potential for health complaints of residents to be linked to CSG activity. The conclusion from the independent medical expert was that he was

“not able to identify any specific clinical condition or pattern that would point to an obvious relationship between the reported health complaints and exposure to chemicals or emissions involved in the CSG industry”(State of Queensland, 2013, p6).

Combining this with the available environmental monitoring data, the Report concluded that a clear link cannot be drawn between the health complaints and the local CSG industry (State of Queensland, 2013, p18).

Recommendations from the Queensland Health Report include providing feedback to the community on environmental monitoring activities and measures, including those related to noise and vibrations and establishing a strategic ambient air monitoring program to monitor CSG emissions and community exposure (State of Queensland, 2013, p19).

It is of particular interest that the Commonwealth Department of the Environment is the lead agency in a study to assess the health and environmental risk of chemicals associated with CSG extraction including drilling and fracking chemicals. Although this review focuses on CSG it will be relevant to shale gas exploitation.

2.5.4 Science - Validity and Mistrust

Throughout the course of the Inquiry, reports, studies and articles were presented to support individual views. Questions about the “validity” and trustworthiness of some research and data emerged from the consultations. In many instances, this focused on discrediting or questioning information and research provided to the Inquiry by those with differing views and was bolstered by the assertion that industry and regulators hold back the details of information gathered through monitoring and testing.

This sense of mistrust is not confined to the NT community: the NSW Chief Scientist and Engineer highlighted one of the concerns associated with CSG activity was an

“uncertainty of the science, a lack of data especially baseline data and a lack of trust in the data sources” (Professor O’Kane, 2013, p2).

The relative lack of publicly available factual information was put to the Inquiry on numerous occasions. Combined with this, is the limited belief in the notion of

“independent” with the suggestion that such research is compromised by funding arrangements.

In addressing value conflicts, mistrust and diversity of viewpoints, ACOLA proposes that these

“complex issues are fundamentally value dilemmas masquerading as scientific questions, and that attention to the science alone will never generate sufficient trust or agreement between the parties so they can create implementable solutions together” (ACOLA, 2013, p.158).

The Inquiry reviewed all information and tested the validity and integrity of sources that were presented as “fact”. For example media reports about a spill of chemicals used for hydraulic fracturing on the Plenty Highway in May this year were frequently referred to. The Inquiry sought and obtained a brief from the operator and authorities to establish the facts of the event and understand response, risks and rehabilitation undertaken. While this is an example of the type of transport incident any industrial activity can experience, the Inquiry was satisfied that the response was appropriate. Scientific research/data collection, transparency of information and independence of sources are important considerations for actors in this debate as well as decision makers.

A compounding factor is that scientists are not always as adept as they might be in communicating their findings to the public in a way that is easily understood.

2.5.5 Short Term versus Long Term Benefits

The notion of only considering short term economic, employment and development benefits as more important than potential long-term environmental impacts was often raised, notably by those aligned with environmental causes.

The INPEX Ichthys LNG project was regularly mentioned as a perceived example of a major project which is only delivering short-term benefits to the local community, with particular reference made to location of the head office in Western Australia and employment opportunities and the associated industry benefits reducing significantly after the construction phase.

The NT Government’s Draft Economic Development Strategy notes that the INPEX project will have spent more than \$5 billion with locally-based businesses during the construction phase (2012-2016) alone.

At the heart of this community feedback is the issue of how industry development impacts on the quality of life and socio-economic profile of populations in

production regions, and the inequities and “costs/benefits” (perceived or otherwise) this can create. For example, the influx of fly in/fly out (FIFO) workers associated with the INPEX project are claimed to have led to significant increases in the cost of living in Darwin.

The Inquiry notes that the “resource curse” (bearing in mind the impacts of various lenses such as constitutional arrangements, types of resources, public policy positions and royalty investment frameworks) has been debated among academics with a range of conclusions drawn (Hajkowicz *et al*, 2011, p 31).

In the NT, the *Petroleum Act* provides a legal framework for collection of royalties on the production of petroleum products at a rate of ten per cent of gross value at the wellhead. This means the royalties are charged on the value of the resources produced.

A number of methods are available to determine the value, with the most commonly applied being the net-back or value-back method. This method calculates the value by taking the sale price of the petroleum product (at the first point of sale) and deducting allowable expenses (production, pipeline and transportation costs between the field and point of sale.) This is different to the royalty framework in place under the *Mineral Royalty Act* which charges royalties based on profit.

Recommendation

The Inquiry recommends that the NT Government considers aligning the petroleum and mineral royalty frameworks.

Some citizens asked whether the incentives provided to the industry represented a significantly higher value of funding and incentives than collected by royalties.

The above concern may have arisen from an Australia Institute Report “Mining the Age of Entitlement”, claiming that the NT Government had spent \$406.7M on industry support in the last six financial years, noting capital investments in ports for gas exports as a significant component.

It is unclear to the Inquiry how the Institute arrived at this figure, which may have been drawn from budget papers and included expenditure on the Marine Supply Base, Port and other infrastructure, which serve other industries.

The Australia Institute quoted the NT Government as having spent \$87.6M in 2013-14 on mineral and fossil fuel assistance. NT Treasury confirmed that \$113M in royalties was collected in that financial year.

The Inquiry understands that expenditure on programs supporting mineral and petroleum industry development in the same period was \$5.6M: \$3.95M for the Creating Opportunities for Resource Exploration program, \$1.5M to support new geoscience programs, and \$0.15M for the International Investment Attraction program.

In addition to the royalty scheme which provides Government revenue to fund services and facilities for the benefit of NT citizens, other methods of community support might also be considered. One such example is a Community Benefit Fund, which the NSW Government is looking at under their new Gas Plan.

The Inquiry also notes that individual organisations have policies on how they support the local community in which they are operating. For example, the Larrakia Trade Training Centre in Darwin received a \$3million donation from INPEX and its joint venturer Total E and P Australia. INPEX has also supported numerous community events and initiatives.

Reserving locally produced gas for local consumption (at lower prices) is also perceived to bring a direct benefit to the community. The recently released “Eastern Australian Domestic Gas Market Study” (released by the Australian Government’s Department of Industry and Bureau of Resources and Energy Economics) discusses options for a domestic gas reservation policy, concluding that such an intervention would have a very limited short term benefit for consumers, and may in fact have negative implications for the supply response and market generally in the future.

The Gas Market Taskforce Report also recommends that a reservation policy not be imposed, as it believes it would not deliver lower priced gas to domestic consumers. It does, however, understand the need for the local market to feel there is a secure and certain gas supply into the future and encouraged industry to voluntarily “ earmark particularly developments for domestic markets” as some gas producers have already done (Gas Market Taskforce, 2013, p34).

The Inquiry supports this position and does not recommend introduction of a Gas Reservation Policy.

2.5.6 Moratorium

More than half of the people who presented or wrote to the Inquiry called for a moratorium on hydraulic fracturing. During the course of this Inquiry, some jurisdictions invoked moratoriums, others decided to support hydraulic fracturing and some reversed previous moratorium decisions.

The Inquiry inclines to the view that Governments take a politically pragmatic way out through a moratorium if they are approaching a particular stage of the political cycle.

Recommendation

The substantive weight of agreed expert opinion leads the Inquiry to find that there is no justification whatsoever for the imposition of a moratorium of hydraulic fracturing in the NT.

2.5.7 Onshore Gas Investment Delays Renewable Energy Investment

The notion that investing in unconventional gas development will delay investment in renewable energy development emerged as a sub-theme of the consultations. This is a complex issue, particularly when considering the full end-to-end production of different energy types and their environmental, economic and social impacts.

Greenhouse Gas Emissions are also discussed elsewhere in the Report.

The Inquiry did note that the broader issues associated with the Energy Mix is addressed to various extents in some of the reference material it drew upon and two particular points of interest in the World Energy Outlook 2011 are noteworthy:

- where natural gas displaces coal and oil driving down emissions, it also displaces some nuclear power pushing up emissions (IEA, 2011, p8). Predictions that gas will reduce emissions relies on commitment to renewables and low emission fuels, such as nuclear, remaining the same; and
- increasingly, pollution policies and climate change considerations are influencing fuel and technology selection, and natural gas is becoming the preferred fuel in end-use sectors and power generation (IEA, 2011, p85).

Chapter Three - Hydraulic Fracturing

A major task of the Inquiry involved investigation of hydraulic fracturing and its associated risks within the NT context.

This relies on detailed scientific and geological data, and the complexity of information can create challenges in conveying understanding to non-industry audiences and the general community.

Any Google search will provide abundant information and discussion about hydraulic fracturing. For example if you google “fracking how stuff works” the first result is a six page article about “How Hydraulic Fracking Works”. A more in depth treatment has been provided by the Society of Petroleum Engineers (2012).

Given the entanglement in a highly contentious and emotive debate, separating out the essential facts, definitions and risk assessments is challenging. The Inquiry observed significant tensions between parties about terminology, use and meaning detracting from productive discussion, as any topic requires some shared understanding and agreement on fundamental information and aspects.

The Inquiry identified critical definitions and information from independent technical experts and respected sources within academia. Information and the evidentiary basis upon which the Inquiry undertook its work follows.

Two fact sheets, produced by the CSIRO, are offered in their entirety: *Shale Gas in Australia* and *Shale Gas Production* in Annex G.

Reports and studies which the Inquiry drew on are also summarised in the next section, along with the criteria applied when reviewing documents for use.

3.1 Hydraulic Fracturing

Hydraulic fracturing involves injecting liquid at high pressure into subterranean rocks, boreholes etc to force open fissures and extract oil or gas. It increases the rate and amount of oil and gas that can be extracted from reservoirs, ensuring economically viable production.

CSIRO reports that hydraulic fracturing has been used widely in Australia within the geothermal and gas industries.²¹ While it has been used by the global oil and gas

²¹ <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/UnconventionalGas/Learn-more/What-is-hydraulic-fracturing.aspx>

industry since the 1940's, hydraulic fracturing was first applied to vertical wells targeting conventional gas in the Amadeus Basin in the NT in 1967.

Hydraulic fracturing for unconventional gas has been used in Australia since the 1990s, mostly in the Queensland and NSW for Coal Seam Gas operations, while it has been used to target shale gas in the NT since 2011.²²

In discussing hydraulic fracturing, it is important to clarify associated terminology and concepts, and the differences and similarities between them:

- conventional versus unconventional gas;
- different types of unconventional gas;
- vertical versus horizontal wells; and
- greenfield versus brown field sites.

3.1.1 Different Gas Types

The industry refers to two types of gas, conventional and unconventional, with the primary difference being the geology of the reservoirs from which they are produced.

***Conventional gas** is obtained from reservoirs of porous sandstone formations capped by impermeable rock, with the gas trapped by buoyancy. The gas can move to the surface through a gas well without the need to pump.*

***Unconventional gas** is generally produced from complex geological systems that prevent or significantly limit the migration of gas and require innovative technological solutions for extraction.²³*

There are several types of unconventional gas including shale gas, CSG, and tight gas. In the NT, the most prominent type of unconventional gas is shale, which can involve horizontal drilling and hydraulic fracturing during production. Further detail is provided in Table 3-1 on the following page.

In response to claims that CSG exploitation was banned in the NT, the Inquiry understands that there are no defined CSG resources in the NT, but exploration and extraction of CSG by conventional methods (which includes hydraulic fracturing) is not excluded under the *Petroleum Act*.

²² <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/UnconventionalGas/Learn-more/What-is-hydraulic-fracturing.aspx>

²³ <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/What-is-coal-seam-gas.aspx>

Table 3-1: Features of types of Gas (Source: CSIRO Fact Sheet, 2012, “Unconventional Gas Facts”)

	Coal Seam Gas	Shale Gas	Tight Gas
Composition	Mostly methane (>95 per cent). Carbon dioxide can be present but makes production less economic. Minor “higher” hydrocarbons, nitrogen and inert gases.	Mostly methane. The presence of other hydrocarbons makes the resource more valuable.	Mostly methane.
Estimated Resource Volume (Australia)	Total identified resources (discovered and undiscovered) estimated to be 235 tcf (GA, 2012).	Total identified resources (discovered and undiscovered) are 396 tcf (IEA, 2011).	The in-place resources (total discovered) are 20 tcf which is expected to increase with further exploration (GA, 2012).
Transport and Market Network	Existing infrastructure for transportation and established market structures, particularly in Qld.	Cooper Basin region has existing gas infrastructure, however resources in WA and NT are generally in remote locations with limited infrastructure. Use by local mines is being considered in some cases.	Existing tight gas resources have been located in conventional gas producing basins (Cooper and Perth basins), close to established infrastructure for commercial production. Other tight gas resources are in more remote locations.
Technology/ Infrastructure Required	Hydraulic fracturing used for less than half of the wells but this use is expected to increase as lower permeability seams are targeted.	Hydraulic fracturing required and horizontal wells often drilled.	Large scale hydraulic fracturing treatments and/or horizontal wells required.
Water Use	Water produced from dewatering (pumping water out of the reservoir to reduce reservoir pressure and allow gas flow). Water required for hydraulic fracturing if used.	Water required for hydraulic fracturing.	Water required for hydraulic fracturing.
Key Extraction Challenges	Removal of water and recycling or disposal of produced water necessary.	Overcoming low permeability. Minimising amounts of water to be sourced for hydraulic fracturing. Reducing infrastructure footprint.	Reducing infrastructure footprint. Minimising amounts of water to be sourced for hydraulic fracturing.
Location	Particularly in NSW and Qld.	Includes remote locations in NT, Qld, SA and WA and some not so remote basins such as the Sydney and Bowen Basins.	Onshore SA, Vic and WA. Largest known resources are in the Perth (WA), Cooper and Gippsland Basins.
Commercial Production	Significant exploration and characterisation of known resources. First commercial production of CSG contributes about 10 per cent of Australia’s total gas production and nearly 80 per cent of Qld’s gas production.	Currently no commercial production and resources are poorly understood and quantified - though Santos announced mid-August what they believe to be the first commercial production of shale gas in Australia from the Cooper Basin.	Currently no known commercial production. Known tight gas reserves in existing conventional reservoirs that are well characterised will be primary targets for exploration and production.
Source Rock	Coal seams (also the reservoir rock).	Low permeability, fine grained sedimentary rocks (also the reservoir rock).	Various source rocks that have generated gas which has migrated into low permeability sandstone and limestone reservoirs.
Gas Occurrence	Primarily adsorbed within organic matter.	Contacted within the pores and fractures (“free gas”) and adsorbed within organic matter.	Contained in pores.
Typical Depth	300 - 1000 metres (shallow compared to conventional and other unconventional gas). Deeper coals exists but are not currently economic as CSG reservoirs.	1000 - 5000+ metres.	Depths greater than 1000 metres.

As described in the ACOLA Report (2013, p34), although they are associated and have many similarities, shale, tight and coal seam gases each have distinguishing properties relating to the host rock, associated water and, to a lesser extent, the production technologies and processes. These lead to significant differences in terms of “explorations, production, economics and environmental impact”.

In setting the scene for this Report, it is important to keep these differences in mind, particularly those between shale and CSG. CSG has attracted significant media and public scrutiny, particularly in NSW and Queensland in recent years, and most debate and discussion around hydraulic fracturing is within the context of CSG.

3.1.2 Vertical versus Horizontal Wells

Two types of wells are referred to: vertical and horizontal.

As the name suggests, a vertical well drops straight down from the surface to the target zone and these are commonly seen in conventional gas operations.

Horizontal wells are initially drilled vertically and then used directional drilling to change to a near horizontal angle so that the well runs parallel to the formation containing the oil or gas.²⁴

Some people were very particular during discussions to distinguish between vertical and horizontal wells, particularly with respect to previous hydraulic fracturing in the NT.

3.1.3 Greenfield versus Brownfield Sites

Greenfield refer to a previously undeveloped site for commercial development or exploitation.²⁵

Brownfield refers to a site that has had previous development.²⁶ This term has transitioned to other industries, however, and within the petroleum industry, it generally refers to previously closed wells that, with the application of modern technology, may become economically viable for production again.

Some industry operators mention that technological advancements raise the opportunity for previously abandoned wells to be “re-commissioned” through hydraulic fracturing and/or horizontal drilling.

²⁴ <http://www.oxfordreference.com/view/10.1093/oi/authority.20110803095944968?rskey=LpII7sandresult=2>.

²⁵ <http://www.oxforddictionaries.com/definition/english/greenfield>.

²⁶ <http://www.oxforddictionaries.com/definition/english/brownfield>.

3.2 Research Documents

The Inquiry noted at its commencement that the emerging unconventional onshore gas industry around the world has led to studies, reviews and inquiries in recent years, all of which explored similar themes. The following reports were identified as fundamental to the Inquiry's work, as they met the criteria of being:

- relevant - they focus on onshore, unconventional gas or specifically on shale gas and/or hydraulic fracturing; and they explore concerns and uncertainties of a community addressing a “growing” gas industry;
- evidentiary-based - they draw on academic studies, scientific data and expert advice from around the world; and they have a holistic view in considering a range of associated aspects and issues;
- independent - the research process and collaborators operated independently and autonomously; they are balanced, explore benefits and risks of hydraulic fracturing and the industry, and consider whether and how risks can be managed suitably; and
- reliable - they are undertaken by panels of highly qualified respected leaders in their fields; they sought advice and input from technical/topic experts; and they are peer-reviewed.

A summary of these reports and their key findings follows.

3.2.1 Engineering Energy: Unconventional Gas Production. A Study of Shale Gas in Australia Australian Council of Learned Academies (ACOLA), May 2013

This study was completed by the ACOLA as one of six initial research topics identified by the Prime Minister's Science, Engineering and Innovation Council in 2012. With the prospect of onshore gas being an integral part of Australia's future energy mix, ACOLA delivered a study of shale gas in Australia which looked at: resources, technology, monitoring, infrastructure, human and environmental impacts, issues communication, regulatory systems, economic impacts, lessons learned from the coal seam gas industry and impacts on greenhouse gas reduction targets.

This Report, which is the most comprehensive study of onshore shale gas in Australia, explores a broad range of issues associated with the industry's development. The review team members were eminently qualified to deliver such a comprehensive and in depth analysis. Moreover, the team consulted extensively with industry members and experts and commissioned a range of detailed reports

and studies to support their work. The ACOLA Report provides 51 findings which address a range of aspects: supply and demand economics of natural gas; reserves and resources; technology and engineering; infrastructure considerations; financial analysis of shale; landscape and biodiversity; water; induced seismicity; greenhouse gas emissions; community issues; monitoring, governance and regulation; and knowledge needs. These findings provide important points of discovery and consideration for all players in the potential development of the shale gas industry.

The major finding of the ACOLA team was that *“whilst shale gas has enormous potential, it will require great skill, persistence, capital and careful management of any impacts on ecosystems and related natural resources, to realise that potential. It will also need an informed and supportive community, and transparent and effective regulations and companion codes of practice. Provided we have all these in place (and the right rocks) shale gas could be an important new energy option for Australia.”* (p.19)

Relevance to NT Inquiry

The ACOLA Report provides an independent, thorough, evidence base which relates directly to the Inquiry’s terms of reference. The Report considers a broad range of issues and addresses risks in a considered manner.

3.2.2 Golden Rules for a Golden Age of Gas: World Energy Outlook, Special Report on Unconventional Gas Office of the Chief Economist, International Energy Agency (IEA), November 2012

The IEA is an autonomous agency which provides two key focuses to its member countries, of which Australia is one.

The objective of the cited report is to *“suggest what might be required to enable the industry to maintain or earn a social licence to operate”* which they consider critical for the industry to flourish (p.15).

The Report’s stated objectives are to:

- describe unconventional gas resources and what is involved in their exploration;
- identify the environmental and social risks, and how they can be addressed;
- suggest the Golden Rules necessary to realise the economic and energy security benefits, while meeting public concerns;
- spell out the implications of compliance with these rules for governments and industry, including development costs; and

- assess the impact of two cases on global gas trade patterns and pricing, energy security and climate change.

The Report found that, among other points:

- *“a bright future for unconventional gas is far from assured: numerous hurdles need to be overcome, not least the social and environmental concerns associated with its extraction”* (p9);
- *“the technologies and know-how exist for unconventional gas to be produced in a way that satisfactorily meets these challenges, but a continuous drive from governments and industry to improve performance is required if public confidence is to be maintained or earned”* (p9); and
- *“the Golden Rules underline that full transparency, measuring and monitoring of environmental impacts and engagement with local communities are critical to addressing public concerns”* (p10).

Relevance to NT Inquiry

The EIA Report provided a strong international context, including how Australia potentially forms part of the global energy future, as well as “facts and figures”. The proposed “rules” also provide a solid foundation for key considerations in approaching how to manage risks appropriately. This is provided from a very broad perspective, so while the general principles are valuable, application of NT specific context and data are still required.

3.2.3 Report of the Nova Scotia Independent Review Panel on Hydraulic Fracturing

Expert panel appointed by the Verschuren Centre for Sustainability in Energy and the Environment at Cape Breton University, September 2014

The Nova Scotia Government requested the Independent Expert Panel to prepare a report to assist with decision making associated with potential industry development. The review considered the environmental, socio-economic and health impacts of hydraulic fracturing and provided recommendations on the potential of hydraulic fracturing to develop unconventional gas and oil resources in the Province.

After examining a range of issues, the Panel’s recommendations focused on adopting a precautionary approach to invest time in discussing and exploring issues, undertaking further research, including base line monitoring, modelling impacts of all forms of energy use and production, and establishing a test for “community permission”. With respect to specific issues, the Panel notes that “as with any

industrial activities there a range of risks and costs”, however, there are also benefits. While there are risks, with well integrity being a considered a critical factor in this regard, they can be managed appropriately with a strong, transparent regulatory and monitoring system which “requires political will and resources”.

The Panel noted that “*some might interpret this as a ‘go slow’ approach or even a de facto moratorium. However, we are not proposing a moratorium or any other political device e.g. a referendum,*” (p5) but encourage the community to take the time to learn about the issues, keep an open mind about future developments, and research the possibilities and risks.

In closing, the Panel offered a range of recommendations should the decision be made for the industry to proceed. These recommendations focused on baseline monitoring, risk assessment and reduction across a range of associated environmental, social and health matters, public participation, regulatory frameworks and best practice for both industry and government.

The Inquiry notes that on receiving the Report, the Government decided to impose a moratorium on hydraulic fracturing within the Province. This evoked a mixed reaction and members of the Panel spoke out publicly to reinforce that they did not recommend a moratorium.

Relevance to NT Inquiry

As a very current body of work undertaken by academics and technical experts, the findings of this review on hydraulic fracturing provide a strong factual basis for the Inquiry to draw on. It also explores in detail a range of community and social licence issues, which were considered and are discussed.

3.2.4 Shale Gas Extraction in the UK: A Review of Hydraulic Fracturing The Royal Society and The Royal Academy of Engineering, June 2012

This Report set out to “analyse the technical aspects of the environmental, health and safety risks associated with shale gas extraction to inform decision makers” (p.5). The work was done at the request of the UK Government’s Chief Scientific Adviser as an Independent Review to inform Government policy making. The terms of reference were:

- *what are the major risks associated with hydraulic fracturing as a means to extract shale gas in the UK, including geological risks, such as seismicity and environmental risks, such as ground water contamination?; and*
- *can these risks be effectively managed? If so, how? (p8)*

A taskforce of eight professors and PhDs in a range of associated areas of expertise oversaw the review, which also consulted with various experts and stakeholders, and accepted submissions from individuals and learned societies. Ten key recommendations were made. The first five focused on specific aspects:

- ground water contamination;
- well integrity;
- induced seismicity;
- leakages of gas; and
- water management.

The remaining recommendations focused on:

- implementing risk management best practice and managing environmental risks, including building mechanisms to enable operators to share data and lessons learnt with each other to promote best practice;
- ensuring regulator capacity and maintaining coordination between the various bodies involved in regulating the industry, including having a lead agency; and
- encouraging relevant research councils to include shale gas extraction in their programs.

The review found that “*uncertainties can be addressed through robust monitoring systems and research activities identified in this report.*” (p5)

Considering the uncertainty about the possible scale of future industry production in the UK, the researchers concluded “*attention must be paid to the way in which risks scale up.*” (p5)

Relevance to NT Inquiry

While not commonly referenced in public submissions, this Report focused on shale gas extraction, reflecting the very high calibre of the associated research and taskforce members. The technical aspects reviewed aligned with the NT Inquiry’s Terms of Reference.

3.2.5 Evaluating the Environmental Impacts of Fracking in New Zealand: An Interim Report

Parliamentary Commissioner for the Environment November 2012

followed by

Drilling for Oil and Gas in New Zealand: Environmental Oversight and Regulation

Parliamentary Commissioner for the Environment June 2014

In March 2012, following requests from Members of Parliament, Councils and the public, the Parliamentary Commissioner for the Environment started an investigation into hydraulic fracturing following growth of concern around the technology. The purpose was two-fold, to assess:

- to assess the environmental risks; and
- to assess whether policies, laws, regulations and institutions are adequate to manage the risks.

During the course of her Inquiry, the Commissioner visited a location which had been using hydraulic fracturing for 23 years. Engagement with the community revealed broader concerns about the industry (and its impact on aspects such as the economy, environment and disbursement of royalties).

Her First Report concluded that *“the environmental risks associated with fracking can be managed effectively . . . but at this stage I cannot be confident that operational best practices are actually being implemented and enforced in this country (p5).”* The accompanying Interim Findings in this Report were that well/drilling location, design and construct of wells, waste disposal and avoiding surface spills and leaks were essential to protecting the environment. The Commissioner also considered that the risk of aquifer contamination is real and the *“salty water that comes from deep underground along with the oil and gas is much greater in volume’* than chemicals used *‘and could also contaminate ground water’*(p6).

The three interim findings about government oversight and regulation were:

- the system (for Government oversight and regulation) is complex and fragmented, making oversight extremely important. The complexity works against transparency and *“important issues can fall between the cracks”*;
- regulation may not be fit-for-purpose, with companies being *‘trusted too much to do “the right thing”*; and
- social licence was not earned (p6).

The Second Report focuses on these key findings, and “*analyses the complex system of laws, agencies and processes that oversee and regulate the industry*” (p5).

In finding the Government oversight and regulation inadequate, the Commissioner offered recommendations about regulations and guidelines of specific activities, such as well closure and ongoing monitoring, to bring them up to international best practice. A strong theme emerged around the inconsistencies in plan and consent conditions between jurisdictions, which led to the first recommendation of Government establishing a stronger national policy position for onshore gas and utilising the Environmental Protection Authority more appropriately in the process (p6).

Relevance to NT Inquiry

As a nation in the early stages of industry development and specifically the use of hydraulic fracturing for onshore gas, these Reports provided a good reference point with respect to additional aspects associated with the practice. The findings and discussion associated with the regulatory and oversight arrangements were of particular interest.

3.2.6 Independent Review of Coal Seam Gas in New South Wales Chief Scientist and Engineer, New South Wales, September 2014

In 2013, the NSW Government asked the Chief Scientist and Engineer to “conduct a review of coal seam gas (CSG) related activities in NSW, with a focus on the impacts of these activities on human health and the environment.”²⁷

Throughout the course of her review, a number of reports and discussion papers were released on specific topics such as insurance and related financial coverage to manage environmental impacts. As a result of a very rigorous program, the Review concluded that “*the technical challenges and risks posed by the CSG industry can in general be managed through:*

- *careful designation of areas appropriate in geological and land-use terms for CSG extraction;*
- *high standards of engineering and professionalism in CSG companies*
- *creation of a State Whole-of-Environment Data Repository so that data from CSG industry operations can be interrogated as needed and in the context of the wider environment;*
- *comprehensive monitoring of CSG operations with ongoing automatic scrutiny of the resulting data;*

²⁷ <http://www.chiefscientist.nsw.gov.au/coal-seam-gas-review>

- *a well-trained and certified workforce; and*
- *application of new technological developments as they become available.” (p iv)*

Accompanying the Final Report was an information paper on managing the interface between Coal Seam Gas and other land uses (setbacks) which provides useful considerations for managing this complex issue.

Relevance to NT Inquiry

The Inquiry has been highly conscious of the distinction between shale gas and CSG, but aspects of managing the nature of CSG also apply to shale gas. This critical body of work explored a range of issues of interest to the Australian context. The work done on the potential impacts on human health was particularly useful, while not specified in this Inquiry’s Terms of Reference.

3.2.7 Gas Market Taskforce: Final Report and Recommendations **Independent Gas Market Taskforce led by former Commonwealth Minister, the Hon Peter Reith, October 2013**

The Gas Market Taskforce was established in December 2012 to provide policy options to the Victorian Government. The Taskforce focused broadly on the eastern gas market: its operation and efficiency, market transparency and transmission and meeting rising demand at competitive prices. A major element of the solutions proposed involved supporting development of the onshore gas industry.

Following investigations related to this theme, the Taskforce concluded that “an onshore gas industry cannot only provide benefits to farmers, revitalise regional communities and create jobs, but at the same time the gas industry can be managed to conserve our environment.”

The Taskforce acknowledge that there are “genuine interests and concerns” (p1) that need to be addressed, but provide recommendations to ensure the most stringent regulatory standards and scientific oversight of the industry. This includes lifting the current restrictions on hydraulic fracturing, about which the Taskforce considers there to be “a lot of exaggeration” (p1). The Taskforce received “compelling evidence” (p1) from independent sources that hydraulic fracturing should be allowed, adding that leading environmental and safety standards must be applied to help allay any concerns.

Relevance to NT Inquiry

The research conducted about hydraulic fracturing, the associated risks and the mitigation technologies that can be applied are particularly relevant to the NT Inquiry. The connection of the northern market and how that may link in with the eastern market was also of interest.

3.2.8 Environmental Impacts on Shale Gas Extraction in Canada Council of Canadian Academies, 2014

This body of work was undertaken by the Expert Panel on Harnessing Science and Technology to Understand the Environmental Impacts of Shale Gas Extraction, to answer the question:

What is the state of knowledge of potential environmental impacts from the exploration, extraction and development of Canada's shale gas resources, and what is the state of knowledge of associated mitigation options?

The Expert Panel noted that assessment is 'hampered by a lack of information about key issues', and water resources and GHG emissions were the two issues of greatest concern. While recognising that industry has made "considerable progress over the last decade in reducing water use by recycling, reducing land disruption by concentrating more wells at each drilling site, reducing the volumes of the toxic chemicals it uses and reducing methane emissions during well completion", the Panel considered that aspects such as cumulative effects on land, fugitive GHG emissions and groundwater contamination remain problematic (pxix).

They considered that there would be five elements of an effective framework to manage risks:

- Technologies to develop and produce shale gas;
- Management systems to control the risks to the environment and public health;
- An effective regulatory system;
- Regional planning; and
- Engagement of local citizens and stakeholder.

Relevance to NT Inquiry

This is a very recent and comprehensive review, which addressed many of the issues contained within the terms of Reference of the Inquiry. There has been a very large and ongoing development of shale gas in parts of Canada, so it provides a useful context to the issues and challenges that the NT may face in the future, and how these may be addressed through regulation and industry practice.

Chapter 4 - Exploring the Terms of Reference

The Terms of Reference (ToR) specify that the Inquiry investigate:

“Hydraulic fracturing for hydrocarbon deposits in the Territory, including the assessment of the environmental risks and actual environmental impacts of hydraulic fracturing and the effectiveness of mitigation measures, and more particularly the matters mentioned in the following seven clauses (ie. Terms of Reference one through seven)”.

4.1 Terms of Reference One and Two

This Chapter deals mainly with:

- ToR 1 “Historical and proposed use of hydraulic fracturing (exploration, appraisal and production) of hydrocarbon deposits in the Northern Territory (number of wells; locations; timeline)”; and
- ToR 2 “Environmental outcomes of each hydraulic fracturing activity for hydrocarbon resources in the Northern Territory (number of wells; frequency of types of known environmental impacts).”

The other Terms of Reference are touched on towards the end of this Chapter and dealt with more fully later in the Report.

4.1.1 Historical Hydraulic Fracturing in Conventional Reserves

Australia has 50 years’ experience drilling for hydrocarbons: hydraulic fracturing has been carried out for the most of this time. Hydraulic fracturing in the NT first occurred in 1967 as a process to promote hydrocarbon production from conventional reservoirs in vertical wells (DME Submission, p7) See Table 4-1 on the next page.

4.1.2 Hydraulic Fracturing in Unconventional Reserves

Hydraulic fracturing targeting unconventional gas began in Australia in 2010 and in the NT in 2011 (DME Submission, p7). In October 2012, Santos announced commencement of the first commercial natural unconventional production in Australia from the Moomba-191 shale well in the Cooper Basin.²⁸ See Table 4-2 on the next page.

²⁸ <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/UnconventionalGas/Learn-more/Unconventional-gas-fast-facts.aspx>

Table 4-1: Hydraulic Fracturing (Conventional Reservoirs) to Date and Ongoing in the NT

Location/ Year	Company	Wells Hydraulically Fractured	Drilling Depth (metres)	Fracture zone (metres)	Comments
West Mereenie Amadeus Basin 1991 - 1994	Santos	7	1310.6 - 1463	23.8 – 74.7	The identical treatment chemicals were used in each of the fracture stimulations with no adverse issues.
East Mereenie Amadeus Basin 1967 - 1996	Santos	20	1402.4 – 1524.4	28.4 - 74.7	The identical treatment chemicals were used in each of the fracture stimulations with no adverse issues.
Palm Valley Amadeus Basin 1973 - 1975	Magellan Petroleum	5	1737.4 – 2194.6		Various chemical treatments were applied and success rates were mixed, with no adverse issues.
Dingo Area Amadeus Basin 1984	Pancontinental	1			Pre-fracturing evaluations only are available.

Table 4-2: Hydraulic Fracturing (Unconventional Reservoirs) to Date and Ongoing in the NT

Location/ Year	Company	Wells Hydraulically Fractured	Drilling Depth (metres)	Fracture zone (metres)	Comments
McArthur Basin 2011	Falcon Oil and Gas	1	2741		No adverse issues in Shenandoah-1.
Georgina Basin 2012	PetroFrontier	3	1916 - 2153		A shallow casing failure occurred in Baldwin-2HST1 and MacIntyre 2H was suspended after hydrogen sulphide gas was detected in the early stages of the frac flow back period.

4.1.3 Challenges

Although the results of exploration drilling for unconventional gas during 2014 were not available at the time of this Report, they should be available in the next few months, providing a signal about what might be possible. This will help to determine whether there is sufficient potential in unconventional resources to merit the substantial investment in research, technological development, infrastructure and extraction costs that will go with commercial production in the NT.

Some constraints may affect production levels and increase the potential costs of shale gas exploration and exploitation. There are differing perspectives on whether the shale gas industry can operate in concert with other significant industries in the NT, particularly agricultural and pastoral sectors.

Pastoralists, growers and Aboriginal land holders are concerned about their negotiation rights under the current legislative arrangements and negative impacts that mining companies may have on their property and roads.

Exploitation will also be affected by the NT's dynamic climate. In the "Top End", for up to six months of the year, monsoonal rains and the possibility of tropical cyclones from December to April impact on accessibility. The wet season poses significant risk to open pit storages for waste water which may overflow into soil and surface water sources. Potential impacts for human, flora and fauna health have also been raised.

The NT's limited infrastructure may be a restriction: with the Stuart Highway and north-south gas pipeline not structured to facilitate access to remote resources. Exploitation will require a large labour workforce and involve construction of access roads and production pipelines.

Hydraulic fracturing requires access to water which may need to be transported to exploration and production sites, although ground water will likely be the main water source in the arid regions. The amount of water required for fracturing will need to be assessed and monitored to ensure existing ground water users retain the supply essential for agriculture, residences, tourism and environmental requirements.

Access to a workforce with the appropriate skillset at a local level may be limited, so many workers are likely to be FIFO, adding significant costs and limitations. Local tradespeople and professionals should have the opportunity to benefit from development of the new industry in the interests of ensuring "social licence" to operate and retaining revenue in the NT.

Well design and construction is a vital aspect of hydraulic fracturing. Wells are designed to extract unconventional resources in the most effective way and to prevent gas or water from leaking to the surface. They can be drilled and hydraulically fractured both vertically and horizontally.

Vertical wells have been the traditional method, but as technology has evolved horizontal wells are now a more common feature. Horizontal wells can be more

difficult to drill and are generally more expensive, but they allow operators to extract more gas from a single well, reduce the impact on surface land use and increase the well's economic viability. Shale gas wells are generally between 1500-4000 metres deep.²⁹

4.1.4 Unconventional Oil and Gas Prospectivity

The Northern Territory Geological Survey recently released a report on the NT's known and potential onshore petroleum geology (Munson, 2014). The information that follows draws primarily on this Report.

The NT's most prospective locations are shown at Figure 4-1 on the next page.

Amadeus Basin

The Amadeus Basin covers an area of 170,000km², mostly in the southern NT to the south west of Alice Springs, with a small part extending into WA.

The then NT Bureau of Mineral Resources began examining the potential for petroleum exploration in the Amadeus Basin in the 1950's, which has been the focal point since the discovery of hydrocarbons there in the 1960's.

In 1963, the Mereenie field was discovered by Exoil NL (later AGL Petroleum Ltd) and Magellan Petroleum Pty Ltd. In 1993, the oil and gas assets of Exoil NL were acquired by Santos Ltd. Magellan Petroleum discovered the Palm Valley gas field in 1965 and the Dingo gas prospect in 1981.

Gas production started in Palm Valley in 1983 and oil and gas production in Mereenie in 1984. The Dingo field, which is targeting conventional reservoir horizons, remains undeveloped, while all production to date from Mereenie and Palm Valley has been from conventional reservoirs.³⁰

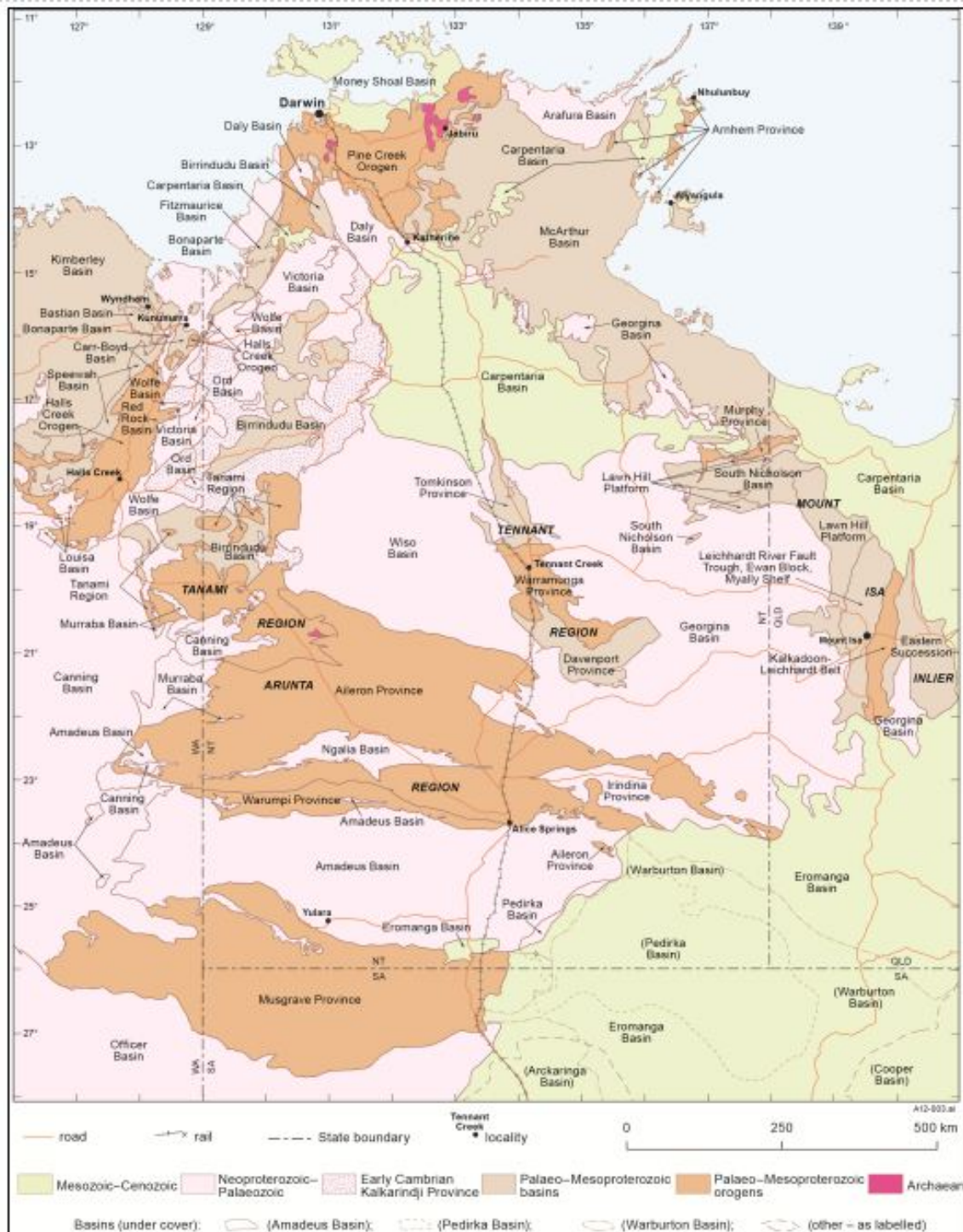
In the late 1980's and early 1990's, other exploration companies took an interest in the Amadeus Basin, including Pacific Oil and Gas Ltd who surveyed the southern portion of the basin.

Pacific Oil and Gas Ltd activities have included geological mapping, geophysical acquisition and drilling two wells which led to the discovery of gas reservoirs in Heavitree Quartzite in Magee-1 in the southern portion of the basin. By 1992, a total of 33 wells had been drilled.

²⁹ <http://www.csiro.au/Outcomes/Energy/Energy-from-oil-and-gas/Shale-gas-potential.aspx>.

³⁰ Email from Colin Cruickshank, Santos Ltd to the Inquiry, 8 October 2014

Figure 4-1: Prospective NT Unconventional Oil and Gas Locations



Geological regions of the NT and surrounding areas; Cenozoic basins and some small outliers/inliers omitted. Subsurface extent of major basins (Arckaringa, Amadeus, Cooper, Pedirka and Warburton basins) in southeast shown with dashed outlines. NT geological regions derived from NTGS 1:2.5M GIS database. WA geological regions simplified and slightly modified from Tyler and Hocking (2001). Extent of Kalkarindji Province in WA slightly modified from Glass and Phillips (2006). Qld geological regions simplified and slightly modified from Denaro and Dhnaram (2009), Geoscience Australia (GA) Geological Regions National Geoscience Dataset and interpretation of TMI image of western Qld supplied by L Hutton (Geological Survey of Queensland). SA geological regions simplified and slightly modified from SA Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE) South Australia Resources Information Geoserver (SARIG: <http://www.sarig.dmitre.sa.gov.au/>) and from GA Geological Regions National Geoscience Dataset. Margins of subsurface Pedirka Basin compiled from Ambrose (2006b), Middleton *et al* (2007), Central Petroleum (2009c) and SARIG.

Source: Northern Territory Geological Survey, 2014, p2

In the early 2000's, Central Petroleum Ltd undertook exploration and by 2012 had been granted tenements or had others under application for the majority of the Amadeus Basin. Seismic surveys were conducted and three wells drilled. A drill hole in Ooraminna-2 near Alice Springs tested large in gas prospect that had already flowed gas to the surface in an old well drilled in 1963.

In 2010-2011, Central Petroleum commenced a drilling project in the west of Central Ridge which had previously been unexplored. Johnstone West-1 tested a significant presence of oil in the Ordovician section. Surprise-1 and Surprise-1 REHST1 were also tested in a deeper portion of the basin, oil flowing freely to the surface without pumping, making this the first major onshore oil flow in the NT in nearly 50 years. In February 2014, a production licence was granted to develop this field commercially.

In October 2012, Central Petroleum and Santos announced a farm out agreement which included the exploration and potential development of up to 13 permit/application areas in the Amadeus and Pedirka basins. In 2013, Santos commenced a four year, three phase exploration project in the joint venture area which includes an 1800km seismic survey program and one exploration well in Mount Kitty-1. The exploration is mainly targeting conventional reservoir horizons, but will also be assessing unconventional targets.³¹

Prior to 2011, Santos and Magellan held joint operating licences for the Mereenie and Palm Valley fields in the Amadeus Basin. In 2011, Magellan and Santos agreed that the Palm Valley and Dingo gas fields would go solely to Magellan, while the Mereenie oil and gas field would go solely to Santos. The two companies also agreed to a 17 year Gas Supply and Purchase Agreement for the sale of nearly all of Palm Valley's remaining gas reserves to Santos. In 2013, Santos announced an extensive drilling and appraisal program to evaluate Mereenie oil and gas resources. The Mereenie program is targeting conventional reservoirs for development and unconventional reservoirs for appraisal purposes.

In 2013, Magellan announced that the Dingo field would commence commercial production in 2015 whereby all gas would be purchased by the Power and Water Corporation in the NT over a 20 year period.

In February 2014, Magellan assets were purchased by Central Petroleum.

³¹ Email from Colin Cruickshank, Santos Ltd to the Inquiry, 8 October 2014

Bonaparte Basin

The Bonaparte Basin is predominantly offshore, but it extends to onshore areas along the NT and WA coasts. The Basin covers an area of 270,000km² with the onshore portion being about 20,000km². Exploration activity has been taking place for many decades on both sides of the NT-WA border. The first indication of petroleum in the basin was in 1939 in a well being dug for water.

In 1959, the first onshore petroleum well Spirit Hill-1 was drilled in the north eastern part of the Burt Range in the NT. Following this, in 1960 the first seismic survey for petroleum exploration was conducted by Austral Geoprospectors. From 1963 to 1965, onshore deep exploration wells were drilled in the WA portion of the basin; good oil and gas shows were recorded which led to drilling Kulshill-2, Moyle-1 and Keep River-1 in the onshore NT portion of the Basin.

Onshore geophysical and drilling projects are underway or planned on both sides of the border. In the NT, the Weaber gas field retention lease is held by Onshore Energy Pty Ltd (a subsidiary of Advent Energy Ltd).

Petroleum exploration licences over the southern NT portion of the onshore Bonaparte Basin are largely owned and operated by Beach Energy Ltd in partnership with Territory Oil and Gas Pty Ltd. The Bonaparte and Milligans Formations are considered prospective for unconventional resources, while the Weaber Group, Langfield Group and Ningbing Group are all considered prospective for conventional hydrocarbon resources.

Georgina Basin

The Georgina Basin, which covers an area of 330,000km² in the central eastern NT and extends into western Qld, is among the most prospective onshore areas for both unconventional and conventional oil and gas. Exploration is still at an early stage with very limited seismic data available.

Hydrocarbons were first recorded within the Georgina Basin as early as 1910 when petroleum odours were noticed during drilling of the Georgina Limestone. Reports of hydrocarbons within the basin continued until the early 1960's when the first significant phase of exploration commenced. Between 1962 and 1983 petroleum wells were drilled, resulting in hydrocarbon shows, but no significant petroleum accumulations were found.

Between 1988 and 1992, Pacific Oil and Gas undertook an exploration project over the southern Georgina Basin which included eight exploration wells. Minor shows were recorded in all wells, but no significant discoveries found.

The most recent unconventional exploration campaign from the mid-2000's to the present focuses on the southern Georgina Basin in the NT, which is being conducted by joint ventures involving Statoil Australia, Baraka Energy and Resources Ltd and PetroFrontier Corporation.

The exploration campaign has included acquisition of 780 line km of seismic data in 2010-2011, 422 line km in 2011 and a further 304 line km in 2013. In 2011-2012, three vertical wells were drilled and completed in Baldwin-2, MacIntyre-2 and Owen-3, which were then re-entered and extended into the lower Arthur Creek Formation as horizontal wells (Baldwin-2Hst1, McIntyre-2H, Owen-3H) in 2012. PetroFrontier attempted to hydraulically fracture these wells in 2012. Due to a shallow casing failure in Baldwin-2Hst1, hydraulic fracturing was suspended. MacIntyre-2H and Owen-3H were successfully completed. A further 20 day flow testing program was completed at Owen-3H, but MacIntyre-2H was suspended due to the start of the wet season and lack of equipment and operators on hand. Exploration projects in this portion of the basin are ongoing.

There has been little exploration in the central and northern parts of the Georgina Basin. In 1962, Amalgamated Petroleum NL drilled a petroleum exploration well in Lake Nash-1. In 1964, two wells were also drilled in the Barkly Sub-basin - Brunette Downs-1 by Papuan Apinaipi Petroleum Company Ltd, and Frewena-1 by the Barkley Oil Company Pty Ltd. Neither of these wells encountered hydrocarbons.

There have been numerous oil shows in drill hole Walton-1, but no other significant petroleum indications have been discovered in this part of the basin.

Ngalia Basin

The Ngalia Basin is an east-west elongate structural basin over 500km in length and up to 90km in width, centred about 300km northwest of Alice Springs.

The Basin was first explored for petroleum in the 1960's and 1970's; Magellan Petroleum Australia Ltd then renewed activity in the 1980's, but only two petroleum drill holes in Davis-1 and Newhaven-1 were drilled, neither of which flowed economic hydrocarbons.³² In 2009, Tamboran Resources Pty Ltd applied for petroleum exploration permits over the majority of the Basin.

³² Email from Geoff Farnell, Tamboran Resource, to the Inquiry, 7 October 2014

Pedirka and Eromanga Basins

The Pedirka and Eromanga Basins are located in the south eastern corner of the NT with the majority of the Eromanga Basin occurring in NSW, Qld and SA. The basins cover a combined area of 70,000km² within the NT.

The Pedirka Basin is largely unexplored for petroleum, while the Eromanga Basin has been extensively explored with significant shows of hydrocarbon in Qld and SA.

In the late 2000's, Central Petroleum Ltd acquired tenements over most of the basins in the NT, and in 2012 Santos Ltd assumed operatorship of Central Petroleum's awarded tenements. Within the NT portion of the basins, nine petroleum and six CSG exploration wells have been drilled and a number of aeromagnetic, gravity and seismic surveys conducted. No commercial conventional or unconventional accumulations have been found to date in these basins within the NT.³³

Beach Petroleum Ltd (now Beach Energy Ltd) conducted some initial exploration phases from 1960 to 1989 in the NT and SA portions of the Pedirka Basin. No commercial hydrocarbons, conventional or unconventional, have been encountered in the Pedirka and overlying basins. Within the Pedirka permits, Central Petroleum drilled two conventional exploration wells and six CSG exploration wells, but coal presence was scarce, and where present, was thin and immature.³⁴

The Purni Formation is prospective for unconventional resources, but any commercial exploitation would need to consider major aquifers in the Great Artesian Basin. This exploration is mainly targeting conventional reservoir horizons, but will also be assessing unconventional targets.

Santos assumed operatorship of EP 93 and had an option to drill a well in Exploration Permit (EP) 97 (Pellinor Block). After technical review, Santos declined the option to drill in EP 97 and withdrew from the Permit.³⁵

McArthur Basin

The McArthur Basin covers an area of some 180,000km², in the north eastern NT, with a small area situated in north-western Qld. The Basin has long been known as having significant potential for unconventional oil and gas. The McArthur Group and Roper Group in the Batten Fault Zone and the Beetaloo Sub-basin are thought to have the most petroleum potential.

³³ Email from Colin Cruickshank, Santos Ltd to the Inquiry, 8 October 2014

³⁴ Ibid.

³⁵ Ibid.

The McArthur Basin has attracted interest from exploration companies since the 1960's. In 1981 and 1984, the first major work was undertaken as a joint venture between Amoco Australia Petroleum Company and Kennecott Copper Corporation which included field mapping, stratigraphic drilling and geophysical surveys.

From the mid-1980's to the 1990's, CRA Exploration Pty Ltd and Pacific Oil and Gas Ltd undertook aerial photography, field mapping, ground geophysics and a substantial drilling program.

In the mid 2000's, an exploration program undertaken by Sweetpea Petroleum Pty Ltd included seismic acquisition, stratigraphic drilling and drilling Shenandoah-1 in 2007 to target large unconventional hydrocarbon resources.

In 2010, Falcon Oil and Gas Ltd took over the exploration program in Shenandoah-1, which was later renamed Shenandoah-1A. In 2011, Falcon Oil and Gas production tested the vertical Shenandoah-1A well with a five stage program which included three limited stimulation treatments of shale and sandstone. The results confirmed the presence of moveable hydrocarbons which led to the Lower Kyalla and Mid-Velkerri successfully being hydraulically fractured for unconventional hydrocarbon resources. Two intervals of Moroak sandstone were tested, but these resulted in low to no hydrocarbon production.³⁶

In 2009, Armour Energy Pty Ltd acquired a substantial area in the southeast of the McArthur Basin and undertook a significant exploration program which targeted conventional and unconventional resources. This program included seismic surveys, surface mapping, airborne gravity and magnetic surveys and the drilling of three wells. In 2012, Armour Energy reported gas in two wells in the McArthur River district, which included the findings of unconventional shale gas in Cow Lagoon-1 and a shallow conventional accumulation in Glyde-1 STI.³⁷ In 2013, Armour drilled the Lamont Pass 3 well and discovered oil 25km north of the Glyde gas well.³⁸

Santos have three prospective permits and applications for a further two permits in the McArthur Basin. In 2013, Santos completed a seismic survey on EP 161 with the initial results promising. On 12 June 2014, Santos commenced vertical drilling of the Tanumbirini-1 exploration well about 420km south of Katherine targeting shale oil and gas. Santos have now completed drilling one of the deepest onshore wells ever drilled in Australia at around 4km deep and are waiting on results of core samples.

³⁶ Email from John Carroll, Falcon Oil and Gas Australia Ltd to the Inquiry, 17 October 2014

³⁷ Email from Robbert de Weijer, Armour Energy Ltd to the Inquiry, 3 October 2014

³⁸ Ibid.

The McArthur can be regarded as a frontier basin from a petroleum exploration perspective, with a lot of attention to the McArthur and Roper Groups in the Batten Fault Zone and Beetaloo Sub-basin. There may be other formations within the McArthur Basin with unconventional potential that are yet to be investigated in detail as most of the basin is currently subject to exploration tenements that have already been granted or under application. All exploration programs in this area are either in the early stages, or are yet to have commenced or be reported.

Wiso Basin

The Wiso Basin covers an area of 160,000km² in central north western NT. It has only been sparsely explored for petroleum, although much of the basin is currently under exploration permit applications. No petroleum wells have been drilled in the basin, but there have been some shallow mineral exploration and BMR stratigraphic drill holes with some minor hydrocarbon shows. Other than a seismic survey in the 1960's, there is no seismic coverage of the Wiso Basin. The southern part of the Basin, the Lander Trough, is believed to have unconventional gas and oil potential, however it has not yet been drill tested. Areas further north in the basin form a relatively thin carbonate platform with limited unconventional gas potential.

4.1.5 Proposed use of Hydraulic Fracturing in the NT

The DME provided extensive information about proposed and future hydraulic fracturing operations in the NT (DME Submission, p8).

In May 2014, Origin and Sasol Ltd announced the signing of a conditional farm in agreement with Falcon Oil and Gas Ltd for three onshore exploration permits (EP's 76, 98 and 117) in the Beetaloo Basin.³⁹ The proposed exploration project will include a nine well exploration and appraisal program comprising one hydraulic fractured vertical well and core study, one hydraulic fractured horizontal well with commercial study and 3C resource assessment, three vertical exploration/stratigraphic wells and four hydraulically fractured horizontal exploration and appraisal wells with micro-seismic and 90 day production tests.⁴⁰

Central Petroleum in collaboration with their joint venture partners, Santos and Total have future plans to target central and southern Amadeus Basins and southern Georgina Basins. Unconventional exploration within these basins is likely to include hydraulic fracturing for production testing.

³⁹ Email from John Carroll, Falcon Oil and Gas Australia Ltd to the Inquiry, 17 October 2014

⁴⁰ Ibid.

As part of a project targeting conventional resources in Mereenie, Santos plan to carry out hydraulic fracturing in at least eight wells from 2014.⁴¹

PetroFrontier and Statoil are working together in a joint partnership to undertake exploration in the southern Georgina Basin. So far in 2014 they have drilled five vertical exploration wells, two of which underwent small scale hydraulic stimulation in order to test their flow potential.⁴²

Tamboran Resources are exploring for unconventional resources within the NT McArthur, Ngalia and Pedirka Basins. In 2014, Tamboran Resources and Santos drilled a well within the McArthur Basin. Further wells are to be drilled in the McArthur and Ngalia Basins in the next two years. Any successful exploration wells are likely to be stimulated by hydraulic fracturing.^{43 44}

Imperial Oil and Gas hold granted exploration permits and have applied for additional permits, all within the eastern McArthur Basin. If unconventional resources are found, the proposed and approved permits include permission to drill and evaluate deviate or horizontal wells which will involve hydraulic fracturing and gas production testing.

Pangaea Resources hold three exploration permits located 45km south of Darwin, and two exploration permits located in the north eastern Birrindudu Basins, 600km south of Darwin. Pangaea completed the initial exploration program in 2013 and the next exploration phase has commenced with drilling the first of three stratigraphic/exploratory wells in 2014.⁴⁵

In 2015, Pangaea is planning to drill four exploratory wells within EP167 and EP168. No fracturing is planned in this drill season.⁴⁶

4.2 Term of Reference Three

TOR 3 “Frequency of types and causes of environmental impacts from hydraulic fracturing for hydrocarbon deposits in the Northern Territory and for similar deposits in other parts of the world.”

Although the first hydraulic fracturing occurred in the NT in 1967 there has been only limited experience with this technology, with less than 40 conventional and unconventional oil and gas wells being hydraulically stimulated. There have been

⁴¹ Email from Colin Cruickshank, Santos Ltd to the Inquiry, 8 October 2014

⁴² Email from Alv Sigve Teigen, Statoil Australia to the Inquiry, 2 October 2014

⁴³ Email from Geoff Farnell, Tamboran Resource, to the Inquiry, 7 October 2014

⁴⁴ Email from Colin Cruickshank, Santos Ltd to the Inquiry, 8 October 2014

⁴⁵ Email from Sarah Jordan, Pangaea to the Inquiry, 2 October 2014

⁴⁶ Ibid.

no demonstrated environmental impacts associated with hydraulic fracturing operations in the NT.

By contrast, there have been an estimated 2.5 million hydraulic fracturing events worldwide, including over one million in the USA (King 2012). Tens of thousands of horizontal wells have also been drilled in the past 60 years and the combination of long horizontal wells and multi-stage fracturing has underpinned the major expansion of the unconventional gas industry, particularly in North America, during the past two decades.

The frequency and cause of environmental impacts associated with hydraulic fracturing specifically, and unconventional gas extraction more generally, are examined in detail in Chapter Five. This draws on evidence primarily from North America, which is documented in a very large number of published studies and summarised in other recent reviews of hydraulic fracturing.

Concerns about the environmental impacts of hydraulic fracturing have focused particularly on contamination of ground water, through a number of potential pathways; the volume of water used during fracturing operations; the nature of chemicals used in the fracturing operations; and the treatment and disposal of waste water.

4.3 Term of Reference Four

TOR 4 “The potential for multiple well pads to reduce or enhance the risks of environmental impacts.”

An important recent development in the unconventional gas industry is the practice of siting multiple wells on a single pad (multiple-well pads). This may have significant benefits, both through reducing costs and development time, and minimising the environmental footprint of well development. Multiple well pads are likely to have greatest benefit when long horizontal wells are being developed, but can also be used with deviated vertical wells.

The potential of multiple well pads is discussed in detail in Chapter Five (Section 5.1), with a finding that the NT Government should work with industry to encourage the use of multiple well pads.

4.4 Term of Reference Five

TOR 5 “The relationship between environmental outcomes of hydraulic fracturing of shale petroleum deposits with geology, hydrogeology and hydrology.”

Local and regional geology, hydrogeology and hydrology are important considerations in mitigating environmental risks associated with unconventional gas operations, including in the location and design of well construction, and in managing the hydraulic fracturing process.

Adequate understanding of stratigraphy, the location of aquifers and ground water that require isolation, the presence of any sub-surface faults, and the nature of other formations that may be problematic for well construction are important in determining well location and designing well casing points and cementing objectives.

Geophysical features of the target formation including depth and thickness, stress regimes, porosity and permeability, pore fluid properties, bedding planes and natural fracture networks. Vertical separation from aquifers and the nature of its intermediate formations are critical elements in designing the hydraulic fracturing events. Along with consideration of the vertical separation from aquifers and the nature of intermediate formations, this ensures that fracture propagation is contained within the target formation.

Surface and ground water hydrology will also be important in determining the source of water for drilling and fracturing; location and design of well pads and associated facilities; storage and treatment options for waste water; and monitoring requirements.

These issues are discussed in detail in Chapter Five, in relation to well site selection (Section 5.1), well design and integrity (5.2), fracture propagation (5.2.2), water use (5.3), waste water treatment (5.5), fugitive emissions (5.6) and well closure (5.9).

Clearly, geology and hydrogeology will vary across potential unconventional gas resources in the prospective sedimentary basins of the NT (Munson 2014).

Variations most relevant to environmental risks include the extent and depth of aquifers; the size of the separation zone between target formations and aquifers; the extent and competency of formations forming a top “seal” over gas reservoirs; and the degree of structural complexity and local faulting (that may influence fracture propagation or induced seismicity).

An assessment of environmental risks associated with any unconventional gas project would be expected to account for the local geological, hydrogeological and hydrological conditions and be sufficiently flexible to incorporate regional variation in these conditions across the NT. For this reason, an objective-based approach to risk management and regulation, rather than a rule-based one, is preferable (as discussed in Section 5.2).

4.5 Term of Reference Six

TOR 6 “The potential for regional and area variations of the risk of environmental impacts from hydraulic fracturing in the Northern Territory.”

The NT has a land area of 1.35 million square kilometres and encompasses a major continental-scale climate from the arid south to the monsoon tropical north, with an average annual rainfall between 200mm and 2000mm⁴⁷.

Associated with this climate gradient and local edaphic variation are a large variety of ecosystems, which can be grouped into 21 bioregions.⁴⁸ Potential shale gas resources underlie a significant proportion of the NT and, while the majority of prospective basins are in the arid and semi-arid zones, unconventional gas operations could occur across much of the climatic and environmental variation found in the Territory.

The risks of environmental impact associated with hydraulic fracturing and other aspects of unconventional gas extraction, and the mitigation of these risks, are discussed in detail in Chapter Five. The general principles for risk assessment and management, and the associated regulatory, compliance and monitoring approach, apply universally. The level of each risk and the appropriate control measures may vary with regional and local conditions, including sub-surface conditions (see earlier comments) and above ground environmental factors.

In relation to the risk of impacts of hydraulic fracturing, variation across the NT in climate and rainfall regimes is particularly relevant to the treatment and disposal of waste water. This is discussed in Section 5.5, with a finding relating to the development of guidance for preferred approaches in different biomes and climate regimes including the acceptable risk level for extreme rainfall or flood events.

Local and regional variation in the risks associated with water extraction for hydraulic fracturing are addressed in Section 5.3.

⁴⁷ See <http://www.lrm.nt.gov.au/plants-and-animals/landscapes-and-wetlands> and associated web pages for an account of environmental and ecological variation in the Northern Territory

⁴⁸ <http://www.environment.gov.au/system/files/pages/5b3d2d31-2355-4b60-820c-e370572b2520/files/bioregions-new.pdf>

Social, cultural and local environmental factors that may influence the selection of well sites are described in Section 5.1. Cumulative environmental impacts arising from large gas field development may also vary regionally according to landscape integrity, resilience and irreplaceability (ACOLA, 2013, Chapter 7).

Chapter Five - Term of Reference Seven

This Chapter deals with:

TOR 7 “Effective methods for mitigating potential environment impacts before, during and after hydraulic fracturing with reference to:

- 7.1 the selection of sites for wells;
- 7.2 well design, construction, standards, control and operational safety and well integrity ratings;
- 7.3 water use;
- 7.4 chemical use;
- 7.5 disposal and treatment of waste water and drilling muds;
- 7.6 fugitive emissions;
- 7.7 noise;
- 7.8 monitoring requirements;
- 7.9 the use of single or multiple well pads;
- 7.10 rehabilitation and closure of wells (exploratory and production) including issues associated with corrosion and long term post closure; and
- 7.11 site rehabilitation for areas where hydraulic fracturing activities have occurred.”

Some of the topics that share common issues have been grouped in the sections below. Most of these include separate sections on monitoring and regulation and all of them detail the Inquiry’s findings. An additional section addressing Induced Seismicity is also included at the end of this Chapter.

5.1 The Selection of Sites for Wells and Use of Single or Multiple Well Pads (ToR 7.1 and 7.9)

Gas well site construction typically involves creating a levelled site of sufficient size to provide a suitable working platform for drilling and well operations, including the associated materials and infrastructure. This entails clearing vegetation, removal and stockpiling of topsoil, then building up the pad with good quality fill to 0.5 to 1.5m thick (depending on local substrate). Erosion control structures may be required, depending on local conditions, and bunding around the hard stand helps ensure any chemical spills are contained.

Excavated, lined pits and/or above-ground tanks are required to store source water for drilling and fracturing, and produced fluids. Fracturing operations also requires temporary storage for proppant and chemicals and space for the fracturing rigs and

control vehicles⁴⁹. Site construction may also include workers' camps, water supply bores and other infrastructure, or these may be "off-site" and service a number of well pads via access roads.

Well pads are about 1.5-3.0 ha in size during drilling and fracturing phases, but after well completion most temporary infrastructure can be removed, partial site remediation undertaken and the production pad size may be less than 0.1 ha.

Site selection is informed by a range of subsurface data indicating where potential for shale gas is likely to be greatest and constraining factors such as the location of faults, aquifers or existing wells. At a local scale, site selection is also influenced by surface-related issues including environmental and ecological factors, local human population distribution, other land uses, cultural heritage compliance, existing surface infrastructure including roads, pipelines and dams, availability of water, suitability for waste management and erosion susceptibility. For example, the Santos submission (pp46-48) stated that prior to new disturbance an ecological assessment is undertaken to evaluate the sensitivity of a proposed location and this informs an internal approvals process that may generate site-specific conditions. Site selection also depends on cultural heritage clearance for both Aboriginal and non-Aboriginal places or objects; and consultation with landowners about issues such as placement of tracks, water extraction and minimising interference with other land uses.

Key environmental and ecological issues affecting well site selection may include:

- presence of or proximity to threatened species, or important habitat for threatened species;
- presence of or proximity to threatened or sensitive ecological communities (for example mound springs);
- local distribution of wetlands or ground-water dependent ecosystems (such as spring-fed monsoon rainforest); and
- local drainage patterns and flow regimes.

Given the small area of a well pad, the environmental risk posed by any individual pad is likely to be low and amenable to mitigation. The use of directional drilling also means that horizontal or deviated wells can access areas where the placement of pad for vertical wells would be environmentally undesirable, or impossible.

⁴⁹ See, for example, photos of well sites in ACOLA (2013), Figs 4.1 and 4.2, p54; King (2012), p27.

Submissions from the Central Land Council and Northern Land Council emphasised the importance of protecting sacred sites and noted that some sites may be diffuse, and may extend below the ground surface.

There is an increasing trend in the unconventional gas industry for multiple wells to be sited on a single pad (multiple-well pads). Directional drilling allows well heads to be close together (5-10m separation) and wells to diverge at depth, both for horizontal wells and vertical wells that have a directional component at intermediate depths. Multiple-well pads confer a number of advantages relating to efficiency of operation, reduced cost and reduction in surface disturbance:

- the latest generation of drill rigs can “walk” short distances while fully assembled, reducing transport time and costs in moving between wells;
- shorter time is taken to reach peak production from multiple wells;
- water supply and waste water tanks or pits can be shared between multiple wells;
- a single access road and gas gathering system can service multiple wells;
- monitoring requirements (e.g. shallow water wells and air quality) can be concentrated;
- total traffic movement for operations and maintenance is reduced; and
- the density of well pads and the proportion of land disturbed within the gas field is significantly reduced.

There may be from two to at least 20 wells on a single multiple-well pad.⁵⁰ While the area required for a multiple-well pad is slightly greater than that for a single well pad, the proportional increase is much smaller than the number of wells on the pad. For example, if single-well pads of two hectare size are used at a density of two per km² across a gas field, then four per cent of the surface area will be directly disturbed by pad construction. If a multiple-well pad with six wells and three hectare size could access the same area of reservoir, then only one per cent of the surface area would be directly disturbed. The difference would likely be somewhat larger if disturbance by access road and pipeline construction were also considered.

In reality, this calculation would be considerably more complex. The economic optimisation of multi-well spacing depends on interaction between a large number of factors, including drilling costs, completion costs, reservoir permeability and porosity, fracture spacing, half-length and conductivity, gas desorption, well performance and gas price (e.g. Yu and Sepehrnoori, 2013). The APPEA

⁵⁰ A 51-well pad has been drilled in the Piceance Basin in Colorado, which accessed c. 250 ha of reservoir from a 2 ha pad (<http://www.energyandcapital.com/articles/multi-well-pad/2892>)

submission (p23) notes that where multiple pads were required to commercialise a field, these pads would be placed between one and four kilometres apart.

The decision by developers to use single or multiple well pads may also be influenced by Government policies and market forces. For example, at least in parts of the USA, the development of single wells may be preferred in order to quickly secure long-term rights to the mineral acreage.⁵¹

Ideally, optimisation of pad spacing or density and well number per pad would also factor in environmental risks, including the impacts of habitat destruction and fragmentation; competition with other land uses (agriculture, Indigenous and pastoralism); and other ecosystem service and human amenity values. Landscape and biodiversity issues associated with shale gas development are discussed by ACOLA (2013, Chapter 7), which notes in particular the cumulative impacts of multiple operations across landscapes and the risk of significant adverse impact through fragmentation, and therefore the importance of a strategic framework for cumulative risk assessment (ACOLA 2013, pp109-111). A number of submissions (including from the Environmental Defender's Office, Northern Land Council, Central Land Council, International Association of Hydrogeologists (NT), Lock the Gate Alliance) also raised the need for cumulative impact assessment.

Multiple-well pads are not used during exploration, where a small number of widely-spaced wells are required. There are, as yet, no examples of multiple-well pads in the NT. The Santos submission noted that (vertical) well spacing intervals in the Mereenie field were not suitable for drilling from a multiple-well pad. However, multiple-well pads have been used in the Cooper Basin, which has resulted in a 55% reduction in surface disturbance compared to single well pads (Santos submission, p25).

Regulation and Monitoring

Land access agreements and the consultation process with stakeholders required before approval for petroleum activity is granted are described in Chapter 6.

The DME submission (p 21) noted that *“Once mining tenure has been granted, DME has no role in the selection of sites of wells. Nevertheless, as part of the process of approving Project or Operational Plans, DME assesses specific well site selections and this includes the requirement to submit an Environment Plan (EP) - which is referred to the EPA for comment”*. Once DME grants approval for an

⁵¹ http://cce.cornell.edu/EnergyClimateChange/NaturalGasDev/Documents/PDFs/Policy_Brief_Sept11-draft02.pdf

operator to carry out a specific activity, no variation of the selection of well sites is permitted without a further approval process.

Clause 109 of the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) under the *Northern Territory Petroleum Act* requires the operator to ensure that operations are carried out in a manner that avoids or minimises any adverse impact on the environment.

DME Guidelines set out requirements for the Environment Plan (DME Submission, Attachment D, pp103-124) which include description of the existing physical, biological and cultural environment; identification of key values and sensitive aspects; environmental risk assessment and treatments; environmental performance objectives, standards and measurement criteria; implementation strategy; reporting and consultation. A summary of the Environment Plan is made publicly available on the DME website.

In the project approval process as described in the DME submission (p19), the Environment Plan is provided to the NT EPA for comment, and DME may also determine a need to provide the Plan to other relevant agencies (particularly DLRM and Parks and Wildlife) for comment. In considering the Environment Plan, the NT EPA may also seek comment from other agencies, and may determine that a Notice of Intent is required under the *Environment Assessment Act*.

Petroleum project applications have been routinely referred to the NT EPA since December 2013, for consideration of whether the application should be treated as a Notice of Intent (NOI). This is determined in line with the NT EPA publication “*Environmental Assessment Guideline: When a NOI is not required for onshore petroleum exploration or production proposals submitted under the Petroleum Act*”⁵². The Guideline has 16 assessment criteria which are used to determine if an NOI is **not** required, relating to issues such as impacts on aquatic systems, stormwater management, erosion control, waste management, impacts on threatened species, land clearing, weeds, heritage clearance, work health and safety, social or economic impacts, and EPBC Act triggers.

A positive assessment would usually require impacts being minimal and/or satisfactorily managed under a relevant Plan (e.g. an Erosion and Sediment Control Plan); a negative assessment against any criterion means the proposal will require an NOI.

⁵² http://www.ntepa.nt.gov.au/_data/assets/pdf_file/0011/349940/guideline_assessment_petroleum_exploration1.pdf

If the NT EPA considers the project has the potential to have a significant impact it will apply the *Environmental Assessment Administrative Procedures*, with the Environment Plan being treated as an NOI. NT EPA circulates this NOI to Government agencies for comment and then prepares a recommendation to the NT EPA Board, which determines whether the project requires a Public Environment Report (PER) or Environmental Impact Statement (EIS) under the *Environment Assessment Act*.

Between January and August 2014, onshore petroleum project Environment Plans for 12 exploration projects, two pipeline projects, one seismic project and four projects that involved fracturing were referred to the NT EPA. A total of 32 oil and gas projects proposals have been reviewed by NT EPA and its predecessor agencies since 2010. Of these 11 were returned to DME with recommendations as not requiring referral as a NOI. The other 21 projects were assessed as an NOI, with comment sought from other Government agencies, and all except one (the Katherine to Gove Gas Pipeline Project, which required an EIS) were determined not to require formal assessment.⁵³

For all projects reviewed by the NT EPA, comments and/or recommendations are provided to DME. For low risk projects (not requiring assessment as an NOI) the comments generally include instructions for the proponent to ensure:

- that heritage assessment and clearance are provided by the Heritage Branch of the Department of Lands, Planning and Environment;
- an Authority Clearance under the *Aboriginal Sacred Sites Act* is provided by the Aboriginal Areas Protection Authority; and
- Environmental Management Plans are developed and effectively implemented to mitigate environmental impacts, including: Ground and Surface Water Management Plan; Erosion and Sediment Control Plan; Acid Sulfate Soil Management Plan (if applicable); Biodiversity Management Plan; Waste Management Plan; Biting Insect Management Plan (if applicable); and Weeds Management Plan.

In correspondence to the Inquiry, the NT EPA indicated that “The information provided to the NT EPA, at the time of notification, is usually insufficient for the NT EPA to determine if there is potential for the project to have a significant impact on the environment”.⁵⁴ This generally required additional information to be requested, either from DME or from the proponent, which added additional time to the assessment process.

⁵³ Data provided by NT EPA, 12 September 2014

⁵⁴ Letter from Dr Bill Freeland to Dr Allan Hawke, 12 September 2014.

The current Project and Environment Plan assessment and approval process for onshore petroleum projects within the NT appears not to be optimally structured, with potentially parallel assessment by DME and NT EPA, both of whom may separately seek advice from other advisory agencies.

Moreover, it is not clear whether the DME requirements for an Environment Plan completely match those of the NT EPA for a Notice of Intent.

A similar but more carefully structured regulatory model has been implemented in South Australia, where the Department of State Development (previously Manufacturing, Innovation, Trade, Resources and Energy) is the lead agency in a “one-stop-shop” approach that satisfies the legislative and regulative requirements of all co-regulatory agencies (DMITRE, 2012, pp133-152). This approach also allows for specified levels of assessment and consultation depending on the level of environmental impact (low, medium, high); and for the development of approved Statements of Environmental Objectives which subsequently form the basis of subsequent activity notification and approval, with reduced regulatory supervision and approvals not being required for “low level official surveillance” activities.

Under the Environment Protection and Biodiversity Conservation Act (EPBC Act) an action (such as petroleum exploration and extraction) requires approval from the Australian Government Environment Minister if it is likely to have a significant impact on a matter of national environmental significance (MNES). Such matters include nationally threatened species and ecological communities, migratory species, Ramsar wetlands, world heritage properties and national heritage places.

The list of MNES was recently amended to include water extraction in relation to Coal Seam Gas and large coal mining developments, but this does not apply to shale gas projects. Detailed guidelines describe the process for assessing whether an action is likely to have a “significant” impact on MNES⁵⁵, and it is the proponent’s responsibility to refer the action to the Department of Environment for a decision about whether it is a controlled action under the EPBC Act.

In assessing a project application, DME and/or NT EPA may advise the proponent that an EPBC Act referral may be required or should be considered. As discussed above, it is feasible that an individual exploration or production well may impact population or habitats of threatened species, or a significant wetland or heritage place, although the spatial extent of such impacts are small and should be readily mitigated, and therefore may not be “significant” under the EPBC Act guidelines.

⁵⁵ <http://www.environment.gov.au/epbc/publications/significant-impact-guidelines-11-matters-national-environmental-significance>

Significant impacts are more likely to be associated with the cumulative effects of extensive development over a gas play, and the associated processing plant infrastructure.

DME's submission notes that current NT legislation does not recognise the use of single or multiple well pads, but this will be addressed in the development of new Regulations to replace the Schedule. DME supports the concept of multiple well pads due to the reduced environmental footprint.

Findings

The Inquiry finds with respect to the Selection of Sites for Wells and Use of Single or Multiple Well Pads, that:

- the environmental (including social and cultural) impact of individual well pads is likely to be small and readily mitigated and regulated, but the cumulative impact of extensive well development over a gas play may be significant. The use of multiple well-pads is likely to reduce the environmental footprint of unconventional gas development;
- the current Project and Environment Plan assessment and approval process should be refined, to provide a one-stop-shop for developers while efficiently and transparently satisfying all legislative and regulatory requirements. This may require better structured arrangements between the lead and co-regulatory NT Government agencies, with the South Australian process providing a useful model;
- the NTG should develop an effective framework for strategic assessment of cumulative impacts of shale gas development, which could be applied if large gas plays (with potentially thousands of wells) are developed in the NT; and
- the NTG should work with industry to encourage the use of multiple well pads in order to reduce the environmental footprint of future shale gas development; including ensuring that there are no perverse policy or regulatory incentives for singular rather than multiple well development.

5.2 Well Design, Construction, Standards, Control and Operational Safety and Well Integrity Ratings” (ToR 7.2)

A major concern with gas extraction and associated fracturing operations is the risk of contamination to aquifers and surface waters. The source of contamination may be chemicals used in drilling and fracturing, oil or gas from the target or other

formations along the well path, or saline or poor quality water from other aquifers intersected by the well.

The potential mechanisms for contamination are:

- well failure or poor well integrity allowing leakage of fluid, oil or gas up the well hole to shallower aquifers or the surface;
- fracturing allowing the migration of fluids, oil or gas through rock to aquifers; and
- surface spills or leaks of chemicals or waste.

This section deals separately with well integrity and fracture propagation, while issues relating to chemical use and waste water management are addressed in Sections 5.4 and 5.5.

5.2.1 Well Integrity

Well integrity has been examined by all recent inquiries into unconventional gas (eg RSRAE, 2012, pp 24-30) and was described in particular detail in NSIRP (2014, pp193-220).

Ensuring well integrity presents a significant engineering and compliance challenge, with significant advances in leading practices during the past few decades as the shale gas industry developed. Many reported incidents that underlie public concern about ground water contamination may be linked to poor well construction techniques in the earlier stages of the unconventional gas and oil industry, and the risks are likely to be much lower for a developing industry in the NT using modern (and future) technology and subject to good regulatory practice. Nevertheless, the risks cannot be reduced to zero and some areas of uncertainty remain, particularly the very long-term integrity of wells.

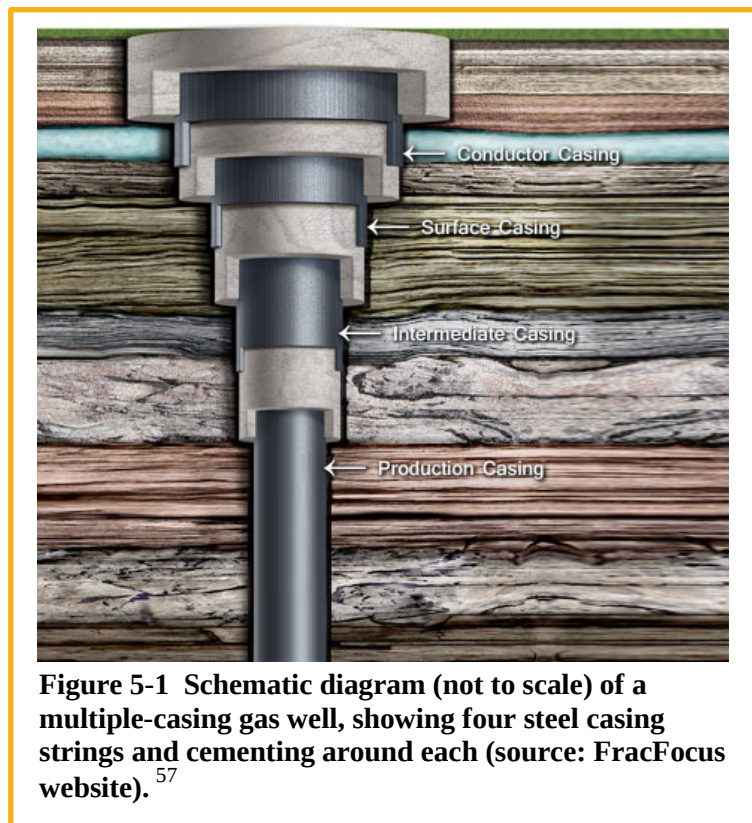
It should also be noted that cased and cemented wells are not unique to unconventional gas extraction, but are widely used for extraction of ground water, conventional oil and gas, geothermal energy and various deeply buried leachable minerals. NSIRP (2014) noted that well engineering design is informed by decades of experience from several million oil and gas wells worldwide, although only a small portion of these are to the great depths associated with shale gas.

The key to well integrity is constructing the well to ensure that it is reliably isolated from subsurface formations, other than those targeted for gas extraction, and there is “zonal isolation” between significant segments of the well profile. This is done by constructing the well with a series of concentric steel casings of decreasing diameter

and increasing depth, with a cement seal between the outer casing and rock, and between casings (Fig 5.2.1a and b).

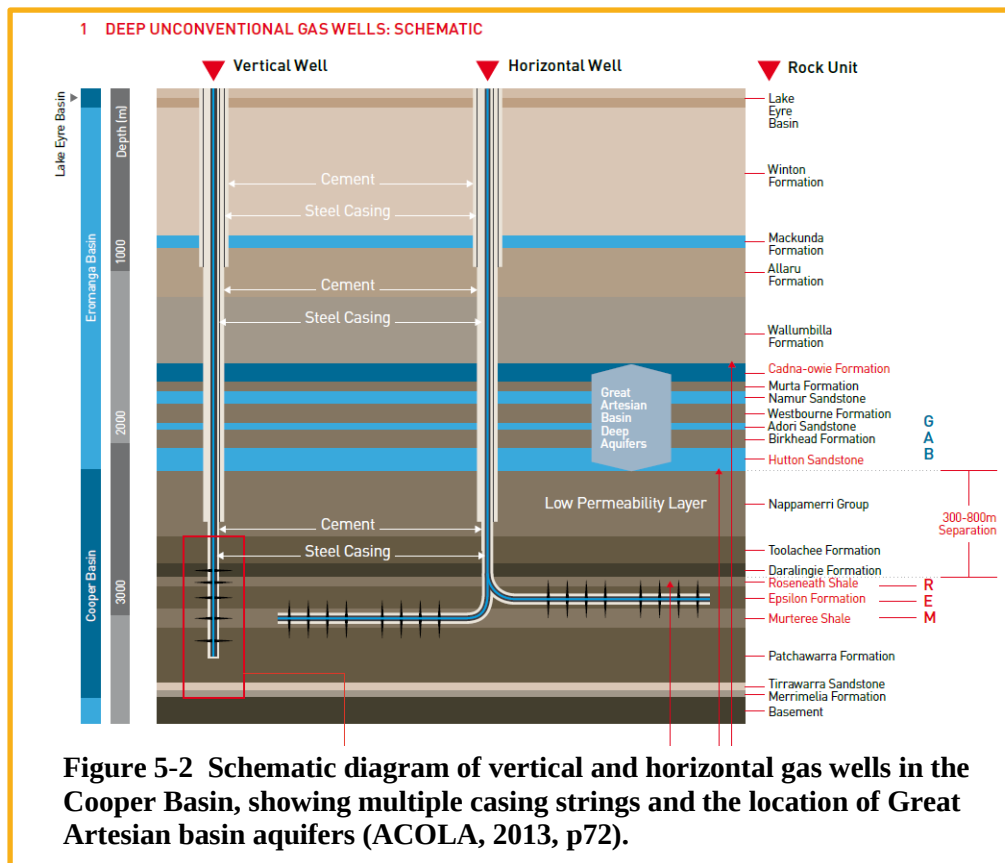
The casing strings⁵⁶ in a shale gas well typically consist of:

- conductor pipe - set into the ground to a depth of about 30m, as a foundation for the well and to prevent caving in of surface soils;
- surface casing - extends from the surface to below any freshwater aquifers (usually several hundred metres);
- intermediate casing(s) - as required to isolate the well from deeper zones that may include saline aquifers, other deep aquifers, thin gas-bearing sands, or unstable or abnormally pressurised formations; and
- production casing - extends to the base of the well through the target formation containing shale gas. During fracturing operations the production casing is perforated within the target formation, allowing gas to flow up through the well.



⁵⁶ “strings” are many joined sections of pipe, which are usually screwed together

⁵⁷ <http://fracfocus.ca/groundwater-protection/drilling-and-production>



The length of the surface and intermediate casing strings is determined on a well-by-well basis according to geological and hydrogeological data collected before drilling and from sampling within the wellbore prior to casing being installed (“open-hole logging”). In one example provided in the Beach Energy submission, a vertical exploration well in the Bonaparte Basin had a conductor pipe to 30m, a surface casing string to 600m, an intermediate casing string to 1800m and the production casing string to the total depth (3,600m), with each string cemented to the surface.

Once the surface casing is in place, a blow-out preventer (BOP) is installed through which subsequent drilling operations pass. The BOP automatically shuts down fluid flow in the wellbore should there be any sudden or uncontrolled escape of fluids, which may potentially occur if drilling unexpectedly encounters an over-pressurised or highly permeable formation or pocket of gas. However, pressure changes within the wellbore are generally routinely managed during drilling by altering the density of the drilling mud. The BOP is also retained during fracturing operations, to ensure that pressure of fluid within the well does not exceed the rated strength of the casing.

Well integrity is influenced by the number of casings and the extent of cementing. Leading practice is for a minimum of three casings, and for all casings to be

cemented to the surface. Integrity also depends on the quality of casing and cementing materials and the standard to which casing is joined, installed and cemented.⁵⁸ Casings are joined carefully at a specified torque, ensuring that threads are in good condition. “Centralizers” are typically attached to the steel casing as it is assembled and lowered into the borehole, in order to keep the casing central in the hole.

A number of techniques are also used to clean the borehole wall and flush out residual drilling mud and fluid before cementing. A cement slurry is pumped down the casing and flows back up the annulus between the casing and rock until this is filled to the surface, and any cement remaining within the casing is displaced and the inside surface cleaned. The well cement slurry used is specifically engineered for this purpose taking into account local geological and hydrogeological conditions. Good cementation is harder to achieve in horizontal wells (CCA 2014).

Various additives may increase strength, resist thermal dehydration, reduce shrinkage, lower permeability, improve ductility or scavenge gas. The high alkalinity of the cement protects steel casing from potential deterioration due to contact with acidic rock or water with high levels of CO₂ or H₂S.

After each stage of casing and cementing is completed, well integrity can be tested by:

- “cased-hole logging”, which includes a cement bond log (CBL) or similar evaluation logs from an acoustic device run inside the casing, that transmits and receives a sound signal to test the completeness and quality of the cement bond between the casing and formation wall; and
- pressure testing, to ensure that a seal has been achieved and that casings have the required mechanical integrity and strength. Pressurising the well bore with water up to ~ 700 atmospheres (70 megapascals) for hold times of ten minutes is typical, but may be higher to exceed maximum expected hydraulic fracturing pressure (ACOLA, 2013, p56).

If these tests reveal flaws, the casing can be replaced or repaired and/or remedial cementing and patching undertaken, or in extreme cases the well may be sealed and abandoned. Similar testing can be repeated after fracturing operations to ensure that well integrity has been maintained, and as required during the production life of the well. During fracturing operations, pressure sensors in the annular regions between casing strings and inside the production casing are used to track pressure changes and detect any breakdown in well integrity.

⁵⁸ A detailed account of casing design, cementing and testing procedures is given in Santos (2014)

In the production phase, it is common for a thinner steel pipe (production tubing) to be inserted within the production casing and all fluids being produced will flow through this tubing. The annulus between the production tubing and the production casing can be monitored during the production lifespan of the well for any pressure change that might indicate a loss of pressure integrity.

Well integrity remains a potential issue of concern once exploration or production wells are decommissioned (the decommissioning process is described in Section 5.9). NSIRP (2014) noted that the length of time over which sealed well integrity will be maintained cannot yet be fully known, as modern well cementation practices are globally only 60 years old, and that this is a complex question that requires further investigation; ACOLA (2013, p128) also noted that more information about the very long-term integrity of abandoned wells will be essential, especially if there is extensive development of gas fields in Australia.

However, NSIRP (2014) also commented that there is currently no evidence of a significant increase in the proportion of leaky wellbores with time; that the products of steel corrosion and cement degradation are solid material, so deterioration over long periods would not simply result in wide open channels to the surface; and that liquid seepage was far less probable through narrow pathways resulting from long-term deterioration than gas (which is discussed further in Section 5.6).

A preliminary risk assessment for ecological and hydrogeological impacts of shale gas development in Australia (Eco Logical Australia, 2012, reported in ACOLA, 2013, p129) concluded that the risk to ground water ecology was moderate and described a range of risk mitigation measures, which predominantly concerned ensuring good well integrity.

Faulty well construction and poor well integrity is one of the major potential risks to ground water contamination. There has been some evidence of ground water contamination in the vicinity of oil and gas production that used fracturing, particularly in the USA, and this issue has been highlighted in public debate - most notably in the 2010 documentary “Gasland”, where a Colorado man lit his water tap on fire. Identifying the cause of contamination is often difficult and/or highly contested, particularly since methane may occur in ground water due to natural seepage. For example, in the case of the Gasland incident, the Colorado Oil and Gas Conservation Commission found that the water contained biogenic gas that was not

related to oil and gas activity, and there was evidence that methane had been present for at least decades previously.⁵⁹

There has also been a tendency to attribute contamination issues generically to “fracking”, rather than elucidate the exact activity or mechanism within the gas exploration or production process that is responsible for each incident, despite this differentiation being crucial to targeting practice reform and policy or regulatory development (Kell, 2011).

Osborn *et al* (2011) found methane in water wells in Pennsylvania and New York State in the USA, suggesting this was related to proximity to shale gas wells in the Marcellus Shale play and implying a causal effect of fracturing. However, Molofsky *et al* (2011) argued that the methane already existed at shallow subsurface levels and had naturally migrated into freshwater aquifers or, in some cases, through poorly constructed wells.

Boyer *et al* (2012) found pre-existing methane contamination in 40% of private water wells that had been sampled, with no significant difference in methane levels between pre- and post-drilling samples. Darrah *et al* (2014) used hydrocarbon abundance and isotopic composition, and a comprehensive analysis of noble gas isotopes, from 133 samples from drinking-water wells in 20 locations overlying the Marcellus and Barnett Shales in Pennsylvania and Texas. They identified eight discrete clusters of fugitive gas contamination distinct from naturally occurring methane - in all cases the gas geochemistry implicated leaks through annulus cement, production casings or underground well failure, but not from gas migration induced by hydraulic fracturing.

Aside from emphasising the primary importance of well integrity, a key learning for the developing Australian shale gas industry from these debates is that resolving the source of methane (or other chemical) contamination of ground water in these contested areas was greatly hampered by a lack of comprehensive pre-drilling baseline water quality samples and studies.

In relation to the potential impacts of CSG extraction, the National Water Commission recommended that baseline assessments of surface and ground water systems should be undertaken to provide a baseline for assessing cumulative impacts on other water users. ACOLA (2013, p179) also noted the need for baseline environmental measurements in relation to shale gas development.

⁵⁹ <http://cogcc.state.co.us/library/gasland%20doc.pdf>

Similarly, RSRAE (2012, pp27-30) recommended that the UK's environmental regulators should work with the British Geological Survey to carry out comprehensive national baseline surveys of methane and other contaminants in ground water; that operators should carry out site-specific monitoring of methane and other contaminants in ground water before, during and after shale gas operations; and that data collected by operators should be submitted to the appropriate authority.

ALL Consulting (2012, pp104-107 and Appendix E) list many of the most prominently reported incidents of ground water contamination in North America between 2001 and 2012, and describe a number in more detail. Many of these cases involved leaks from old abandoned wells, leaks associated with poorly constructed, sealed or cemented wells, or surface spills or improper release of chemicals and waste water, but in none of these listed cases was hydraulic fracturing itself unequivocally determined to be the pathway for ground water contamination.

Groat and Grimshaw (2012) also analysed numerous reported environmental incidents associated with oil and gas development, concluding that there was little or no evidence of ground water contamination resulting directly from hydraulic fracturing.

A few studies have attempted to estimate failure or leakage rates from data across a large number of wells. Kell (2011) examined ground water incident investigations in Texas (between 1993 and 2008) and Ohio (1983-2007). Most of the 396 reported incidents were related to construction and maintenance of reserve pits, waste management and disposal, or orphaned wells, and a large proportion of incidents occurred early in the study periods. In Ohio, where over 33,000 wells were drilled in the study period, 12 had incidents related to well construction deficiencies, and six of these wells had the surface casing sealed with clay rather than cement. In Texas (187,888 wells) only two incidents were attributable to deficient well construction practices, including one caused by a short surface casing that did not adequately isolate the basal section of the useable ground water aquifer. During the study period for Texas, over 16,000 horizontal shale gas wells with multi-stage hydraulic fracturing were completed. No ground water contamination incidents were reported from any of the drilling, construction, fracturing or production operations of these horizontal gas wells.

These data have been used to infer a probability of casing failure leading to aquifer contamination of 0.03%.⁶⁰ This may be somewhat disingenuous as it assumes all

⁶⁰ eg. <http://energyindepth.org/national/well-casing-failure-rates/>

incidents were observed, reported, investigated and the cause accurately described but, equally, may be a significant underestimate for future developments as most of the reported causes of failure would not have occurred with current practice.

Watson and Bachu (2009) used data from 315,000 oil, gas and injection wells in Alberta, Canada to assess gas leakage pathways. They found gas migration (GM) leakage in 0.6% of wells and surface-casing vent-flow (SCVF) in 3.9% of wells, and reported that exposed (uncemented) casing was the main factor in the occurrence of leakage and casing failure. Some leaky wells had only a single casing or were left uncased below the surface aquifer, had not been cemented or cementation had not reached required depth. They concluded that leakage was mostly due to mechanical factors controlled during wellbore drilling, construction and abandonment, mainly cementing.

King and King (2013) emphasise the difference between single barrier failures in multiple-barrier well design (where containment is maintained and no pollution indicated) and actual well integrity failure (where all barriers fail and a leak is possible), which is one to two orders of magnitude rarer than the former. From a large collation of government, academic and industry reports, mostly from North America, they concluded that oil, gas and injection wells have an overall leak frequency of 0.005% to 0.03% for wells currently in service, with lower frequencies in more recent developments.

Some submissions to the Inquiry made use of these or similar well failure rate estimates to argue that even such low probabilities were problematic in the context of the very large number of wells projected to be developed in the NT (e.g. “0.03% - 0.005% x 68,000 wells = 12-20 leaking wells as an absolute minimum”: Arid Lands Environment Centre submission). However, as discussed in Section 5.3, a more realistic scenario is the development of around 100 wells per year and a large commercial field may have some 3000 wells. Moreover, if good practice and strong regulation are enforced, then monitoring should ensure that leaks are quickly detected and remedial action taken.

Regulation and Monitoring

There are very detailed industry standards and government guidelines and regulation relating to well construction and well integrity, both nationally and internationally, and these have evolved with well construction experience and technological advances.

The most cited industry guidelines for shale gas well construction and integrity are from the American Petroleum Institute, notably the *Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines* (API 2009) and associated standards,⁶¹ and most major shale and coal seam gas proponents operating in Australia state that they adopt (or exceed) these as the minimum standard. Various industry documents and the submission from the Australian Petroleum Production and Exploration Association (APPEA) also refer to the APPEA Code of Practice for Hydraulic Fracturing, although peculiarly this Code is not documented on the APPEA website.

Well integrity in all Australia jurisdictions is managed through their petroleum legislation and regulations, and generally reference international standards for “good industry practice” (SCER, 2013, pp26-34). The NSW and Queensland Governments have developed codes of practice that stipulate specific requirements for well integrity (in Coal Seam Gas extraction) - the *Code of Practice for Construction and Abandoning CSG Wells in Queensland*⁶² and the *NSW Code of Practice for Coal Seam Gas - Well Integrity*.⁶³

Both codes mandate that the design basis for wells must:

- consider casing setting depths that take into account aquifer and production zone locations, and the requirements for well control;
- provide for installation of a blowout preventer;
- use appropriate casing weight and grade, and casing running procedures
- use appropriate well design and construction materials;
- use appropriate casing centralisation;
- use engineered cement slurry and effective cement placement techniques; and
- be designed to ensure all fluids produced from the well travel directly from the production zone to the surface without cross contamination.

Each Code describes mandatory requirements and additional “good industry practice” for each aspect. They also mandate monitoring and maintenance requirements, and specify mandatory well abandonment requirements.

In the NT, well design and well integrity are addressed in Clauses 501-532 of the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) under the *Northern Territory Petroleum Act*. As detailed in their submission, DME

⁶¹ A more comprehensive description of the range of relevant API guidelines and standards is found at: http://www.api.org/~media/Files/Policy/Exploration/Hydraulic_Fracturing_InfoSheet.pdf; <http://www.api.org/policy-and-issues/policy-items/hf/hydraulic-fracturing-best-practices>

⁶² <http://mines.industry.qld.gov.au/assets/petroleum-pdf/code-of-practice-csg-wells-and-bores.pdf>

⁶³ http://www.resourcesandenergy.nsw.gov.au/__data/assets/pdf_file/0006/516174/Code-of-Practice-for-Coal-Seam-Gas-Well-Integrity.PDF

requires a work program to be submitted as part of their project assessment process which includes details relating to well design, construction and integrity. Internal DME checklists ensure that the operator has addressed critical operational and well safety issues including:

- all activities and material meet or exceed API standards;
- blow out preventer (BOP) Systems;
- cementing of all casing strings to surface;
- mandatory water quality testing; before during and after the activity;
- mandatory validation of casing and cement using Cement Bond Logs;
- mandatory validation of all barriers by pressure testing;
- mandatory Formation Integrity Testing;
- pressure monitoring provides confirmation that well integrity has not been impacted by fracture stimulation activities; and
- installation of a Completion Tubing string.

In relation to water quality monitoring, the DME Guideline for Environmental Plans says that approval is conditional upon the operator providing plans for regular testing of local water bores before, during or after the project, although there is no further detail about the nature of testing required, or how the water data is assessed or databased.

At least some of the issues addressed in the DME internal checklists are not mandated, or mandated to the same extent, in the *Schedule* (for example, the *Schedule* does not require cementing all strings to the surface, or mention water quality testing). The DME submission stated that new Regulations are being developed to replace the current *Schedule* and overcome these shortcomings.

Variations to approved work programs are not permitted, and self-reporting, audits and inspections provide the compliance framework. DME or third party inspectors have the power to carry out operational audits, and desktop auditing of specific well integrity and barrier validation triggers can confirm that the well was constructed to meet or exceed standards. Some reporting may have even daily requirements (eg. drilling logs). Details of application assessment guidelines, program assessment checklists and site audit checklists were provided in the DME submission (Attachment D).

The UK hydraulic fracturing review (RSRAE, 2012, pp48-52) has a useful discussion of the benefits of a goal-based approach to regulation, as opposed to a more prescriptive or rule-based one.

A prescriptive approach, which sets out universal standards to be met, tends to support routine practices and limit innovation in risk management. A prescriptive approach may also be less proportionate and flexible to local site-specific risks, or to the introduction of new technologies or best practice. A goal based approach requires operators to identify and assess risks in a way that fosters innovation and continuous improvement in risk management. An intermediate option is to develop sector-specific guidelines that assist operators to carry out risk assessment to the required level (such as the “As Low as Reasonably Practicable” [ALARP] principle). The operators may need to demonstrate internal processes to explain how risks can be managed to ALARP (for example, in contracting service companies), and demonstrate mechanisms in place to audit their risk management processes.

Risk assessments are submitted to regulators for scrutiny and enforced through monitoring and inspection. A key element of this approach is that data in incidents and accidents is (anonymously) shared in order to improve risk assessment and best practice (Maitland *et al* 2011; RSRAE, 2012, p49).

The South Australian regulatory regime under the *Petroleum and Geothermal Energy Act* and associated *Regulations (2013)* provides a good model of this approach, through the Environmental Impact Report (EIR) and Statement of Environmental Objectives (SEO) process (DMITRE, 2012, pp133-152).⁶⁴

Licensees can be classified as carrying out activities requiring high or low level official surveillance. A low level surveillance classification is earned through the licensee demonstrating good procedures, management systems and track record, and is very desirable in reducing regulatory load.

Findings

The Inquiry finds with respect to Well Design, Construction, Standards, Control and Operational Safety and Well Integrity Ratings, that:

- ensuring well integrity is a key aspect of reducing the risk of environmental contamination from unconventional gas extraction. Application of leading practice in well construction combined with rigorous integrity testing and effective regulatory oversight should result in a very low probability of well failure, but a ground water monitoring regime that can detect contamination attributable to unconventional gas activities is also desirable;
- the NTG should consider developing a Code of Practice for Shale Gas Wells, similar to those of Queensland and NSW for CSG wells. This should serve to

⁶⁴ EIR and SEO reports are publicly available at

http://www.pir.sa.gov.au/petroleum/environment/register/seo_eir_and_ea_reports/drilling_activity_reports

formalise some internal DME regulatory practices that are not adequately covered in the current *Schedule*;

- the NTG should work with industry and other Australian jurisdictions to ensure a consistent understanding of “leading industry practice” in relation to gas well construction and operation; and leading practice should be regularly reviewed with new or improved standards being promptly adopted and mandated as appropriate;
- regulation of shale gas extraction should embed standards and guidelines within a goal-based approach that, among other aspects, clearly elucidates the objective of avoiding aquifer contamination;
- the NTG needs to ensure that assessment, regulatory and compliance functions within its agencies are adequately resourced, and that appropriate expertise is obtained and maintained to keep pace with the rapidly developing technology and to satisfy industry and community expectations for a good regulatory framework;
- a transparent framework for reporting, investigation and resolution of, amongst other aspects, ground water contamination incidents should be maintained, both to build public confidence and refine risk assessment and best practice; and
- the NTG should collaborate with the Australian Government, research institutions and industry to develop a strategic approach to building a baseline for ground water quality, including natural methane levels.

5.2.2 Fracture Propagation

The risk of contamination to aquifers and surface waters is a major concern with gas extraction and associated fracturing operations. As outlined above, the most likely mechanisms for contamination are poor well integrity, leaks from abandoned wells or surface spills - issues common to the oil and gas industry, whether conventional or unconventional. However, public concern often focuses on the process of hydraulic fracturing itself, and the risk that fracturing may allow the migration of fluids, oil or gas through rock strata to contaminate aquifers.

The aim of hydraulic fracturing is to create a network of small (millimetre scale) cracks in low permeability shale or tight sand target formations, through which gas can flow back to the well. Fracturing occurs around a carefully selected segment of the well, by pumping fracturing fluid at very high pressure through perforations in the production casing. This segment is typically 50-200m long, and temporary plugs may be used to divide the well into multiple segments (“stages”) lying within the target formation that are fractured sequentially, from the furthest end toward the

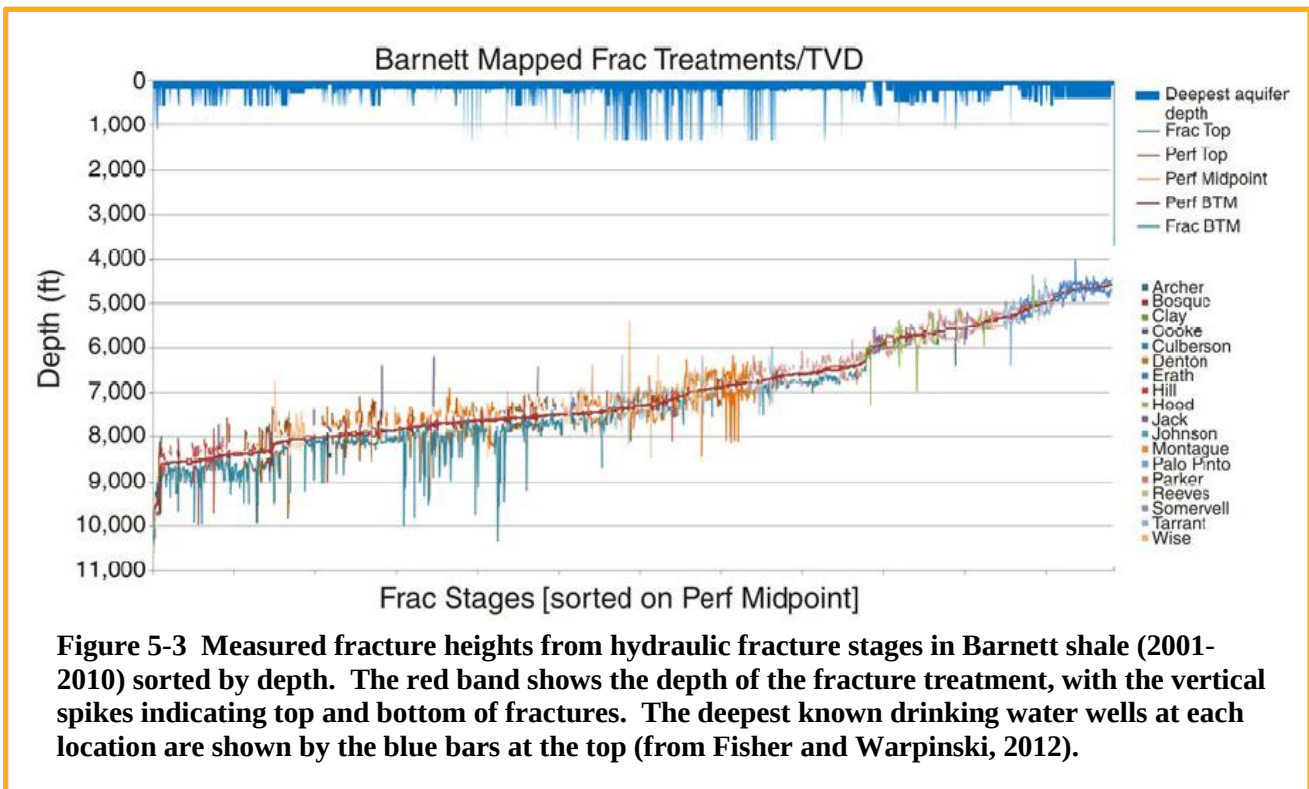
start of the well⁶⁵. Fractures in the rock radiate out from the casing, with the greatest amount of fracturing aligned with the direction of maximum principal stress in the rock strata. At depths greater than 600m, the vertical stress or overburden is generally the largest single stress, so the principal fracture orientation is likely to be vertical.

The distance that fractures travel through the rock is of critical importance. The intention is to maximise fracturing within the target gas-bearing strata, while minimising the spread of fractures outside this area. In particular, if fractures travel a long distance they could open conduits to other strata, including aquifers. Excessive fracture growth is also economically undesirable, as it means that excess fracturing fluid and/or pumping pressure have been used.

Fracture growth can be monitored by a number of techniques, particularly tiltmeters and microseismic monitoring. Tiltmeters are placed in shallow boreholes around the site, or in deep offset wells to estimate fracture geometry. Microseismic sensors are arrayed in an offset well at similar depth to the fracturing stages to detect the location and energy of shear fracturing (ACOLA, 2013, p62; Fisher and Warpinski, 2012). The results of microseismic monitoring from a typical fracturing operation in the Barnett Shale in Texas, USA, is illustrated in RSRAE (2012, pp31-32).

Monitoring data for the vertical extent of fracture growth has been collated for thousands of fracture treatments in four major US shale formations between 2001 and 2010 (Fisher and Warpinski, 2012; Fig. 5.2.2). This showed that fracture height growth is generally greatest in the deepest wells; that most fracture growth is contained within 100-200m; and that occasionally there are spikes of longer fractures, to a maximum of approximately 500m. In all cases a very large separation was maintained between the upper limit of fracture growth and the deepest known local potable water aquifers. A similar pattern of fracture growth heights was observed in each of the four basins, despite significant differences in geological complexity. Vertical fracture growth is naturally constrained by the layering of material in sedimentary basins with interfaces and variability in rock stress that kink, bifurcate and restrict fracture growth (Fisher and Warpinski, 2012). Additionally, the volume of fluid required to create the pressure to open fractures increases with the length of the fractures, and fracturing fluid would “leak off” as fractures encountered more permeable layers, so that the pressure required to propagate fractures across thousands of metres of rock can neither be achieved nor sustained.

⁶⁵ Stage length depends on site-specific wellbore conditions as well as operator preference and experience; the trend is to a greater number of shorter stages, as shorter stages may give better production response.



The larger spikes in fracture growth in the data of Fisher and Warpinski (2012) are interpreted as a result of hydraulic fractures intercepting faults, and this appears to be the greatest area of risk with fracture propagation. Davis and Robinson (2012) cited a maximum observed fracture height of 588m for a hydraulic fracture that extended into a pre-existing fault. Fisher and Warpinski (2012) argue that faults through hydrocarbon reservoirs must necessarily be closed, otherwise hydrocarbons would already have escaped over geological time through this path; and that the height of fracture propagation through closed faults is constrained by similar fractures limiting growth in competent rock. The application of this argument to gas reserves in low permeability shale strata has, however, been challenged (RSRAE, 2012, p34).

Existing faults within an area targeted for gas extraction can be mapped and modelled using seismic, gravity and magnetic data, and known faults avoided during drilling and fracturing. Additionally, real-time monitoring during the fracturing process can alert the operator to any anomalous events - such as fracturing intercepting a fault - and remedial action taken (see below).

Even if a pathway is created during fracturing between deep and shallow formations, this does not mean that fracturing fluid, gas or brine would necessarily flow into shallow aquifers. This would require suitable pressure and permeability conditions, as well as sustained hydraulic pressure once fracturing is completed.

Analyses suggest upward flow of fluids via fractures to the shallow fresh water zone is highly unlikely (RSRAE, 2012; ALL Consulting, 2012, pp 96-97).

While most groundwater bores in the NT are within 200m of the surface, there can be very significant aquifers at greater depth, notably in the Great Artesian Basin (GAB). This is illustrated in Figure 4.5 in ACOLA (2013, p72) showing the deepest GAB aquifer within the Cooper Basin, where the Hutton Sandstone is vertically separated by 300-800m from the Roseneath Shale which would be the target formation for fracturing. This relative proximity emphasises the importance of excellent well integrity at depth, and best-practice modelling and monitoring of hydraulic fracturing to ensure isolation, including through avoidance of any transmissive fault structures. It should be noted, however, that conventional wells in the Cooper Basin have extracted oil and gas from deep GAB strata for many years without serious incident.

An additional issue is that some Australian basins are extremely hot at depth, which precludes the use of some instruments used in microseismic monitoring of fracture propagation.

For many Australian shale gas basins there is a lack of detailed information on their deep stratigraphy, faults, discontinuities, stress distribution and deep hydrogeological processes (ACOLA, 2013, p130). FROGTECH (2013, p36) discussed the need for an integrated scientific program to develop a “*comprehensive model of the tectono-stratigraphic framework of shale gas basins including mapping faults, fractures, lithology, tops and bottom of key units, stress direction, facies architecture, etc*” which would serve as a basis for ground water and other modelling and be iteratively expanded as more data become available. The submission by the International Association of Hydrogeologists (NT Branch) also noted that the hydrogeology of deeper aquifers in the NT is not well understood and there is a need for much improved hydrogeological conceptualisation, as well as renewing the local knowledge base and experience in this field.

Potentially significant differences in stress regimes in Australian compared to North American shale gas basins may influence how fracturing for unconventional gas is implemented. Deep shales in USA basins have a “relaxed” or “extensional stress” regime, with the maximum principal stress in the vertical direction. Consequently, at deeper than 1200m there is an average 80% vertical component of fractures (Fisher and Warpinski, 2012), which is favourable for fracturing from long horizontal wells drilled in the direction of least horizontal stress (see ACOLA, 2013, Fig. 4.3, p68).

Some Australian basins may, however, may have “compressive stress” where the horizontal stress at shale target depths approaches or exceeds the vertical overburden stress. This could lead to fractures having a greater horizontal component, something more suited to fracturing from vertical wells. Two vertical wells in the Cooper Basin drilled, fractured and monitored to test this issue showed predominantly vertical fracture growth in one well, but horizontal fracture components above 50% for two intervals in the second well 25km away (Pitkin *et al*, 2012). The trial development of horizontal wells in the Cooper Basin and other Australian shale gas basins will help to clarify this issue.

In some Australian basins the mixed lithology of the deep unconventional resources constitute a continuous gas play that may also be best accessed by hydraulic fracturing stages at different depths within vertical wells (ACOLA, 2013, p65).

Incidents of ground water contamination associated with conventional and unconventional gas extraction were discussed in Section 5.2.1 and the primary mechanisms identified as poor well integrity, leaking abandoned wells and surface spills. Several studies and reviews have concluded that there is no unequivocal evidence of ground water contamination directly attributable to fracture propagation from hydraulic fracturing at “normal depths” (below 1200m), and no evidence of chemicals from fracturing fluids in contaminated water wells (RSRAE, 2012, p12; Groat and Grimshaw, 2012; Peterson and Hamilton, 2013).

One exception may be ground water contamination at Pavillion, Wyoming. The suspected source of contamination were two conventional gas wells in the Wind River Basin which had been fractured to increase production - in this case, fracturing occurred within 372 meters of the surface, with water bores extending to as deep as 244m (DiGiulio *et al* 2012). The Nova Scotia Review cautioned that statements that no impacts of hydraulic fracturing on ground water quality have been proven or verified should not be misinterpreted as declaring hydraulic fracturing a risk-free process (NSIRP, 2014, p179).

Regulation and Monitoring

Planning and undertaking a hydraulic fracturing operation is a complex process generally done by large service companies (e.g. Halliburton, Schlumberger) with extensive experience. Designing the fracture operation involves computer modelling using data from seismic assessments, drilling logs, well-hole logging and previous stimulation treatment data (for detailed descriptions see ALL Consulting, 2012, pp6-26; Santos submission, pp31-33).

Detailed monitoring during a fracture treatment provides additional data about the performance of the fracture which feeds back to iteratively improve the fracture growth models for future stages, or other wells in the same target formation. Microseismic and tiltmeter monitoring (see above) provide the most information about fracture extent and geometry, but are relatively expensive to implement, particularly microseismic monitoring that requires an offset well of similar depth to the fracture operation. Therefore, these technologies are mostly applied during exploratory drilling and early development phases until fracture dynamics within that area are relatively well understood (King, 2012, p29). There are also some limitations on the use of microseismic sensors in very hot strata ($\sim 200^{\circ}\text{C}$), such as found in parts of the Cooper Basin.

Real-time monitoring of fracture treatments includes wellhead and downhole pressure, pumping rates, additives and water volume, and fracking fluid density - allowing real-time adjustment to the fracturing process, or interrupting it if there are safety hazards or anomalous incidents (e.g. Santos submission, pp31-33). In particular, tracking bottomhole pressure shows a characteristic signature associated with fracture initiation, breakdown and propagation (e.g. ACOLA, 2013, Diagram 2, p70) and deviation from this may indicate intersection with a fault and prompt remedial action.

Pressure sensors in the cemented annular region between casing strings can also detect any breakdown in well integrity during fracturing. Other monitoring methods during and after the fracture operation may be informative about fracture performance, including proppant tagging, chemical tracers, temperature measurement and fibre-optic sensors (ACOLA, 2013, p62; King, 2012, Table 4; ALL Consulting, 2012, pp63-66). The use of fibre optic sensors is a potential alternative to electronic gauges in high temperature conditions and increasingly detailed real-time fracturing diagnostics is an area of rapid technological development within the industry.⁶⁶

Well design and operations in the NT are addressed in the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) under the *Northern Territory Petroleum Act*, although the *Schedule* does not address issues specific to hydraulic fracturing.

The DME submission describes the requirement for a work program which includes details relating to well design and construction to be submitted as part of their project assessment process. “Fracture Stimulating” is one of the well activities that

⁶⁶ See, for example, <http://www.halliburton.com/en-US/ps/pinnacle>

requires specific Operation Approvals in addition to a Project Approval. Internal DME assessment checklists (DME submission, Attachment D) are designed to ensure that the operator has addressed critical operational and well safety issues including:

- all activities and material meet or exceed API (American Petroleum Institute) standards;
- safe separation between shallow aquifers and the hydrocarbon target zone (section to be fractured); and
- submission of fracture modelling confirming maximum fracture height and length, hence confirming safe separation.

DME guidelines and assessment checklists do not, however, appear to address the nature or extent of monitoring required during or after fracturing, other than that relating to well integrity testing.

In correspondence with the Inquiry, DME indicated that:

*“The minimum distance accepted by DME is half a kilometre between the top of a fracture and the bottom of the aquifer (500m). Beside the actual distance, the main factor taken into account is the existence of any impermeable formations between the uppermost fracture and the shallow water aquifers - eg.: the Stokes Siltstone is acting as a regional top seal across the Mereenie field. By industry standards, half a kilometre separation is considered conservative especially with the presence of a regional top seal and given that formal fracture modelling, explicitly stating the maximum fracture propagation heights, must be submitted with an operator’s application”.*⁶⁷

It should be noted that fracture modelling depends on estimating a large number of variables which “make the first estimates of computer modelling less than ideal” (King, 2012, p30), so that the maximum fracture heights from modelling within relatively poorly known NT basins must be treated cautiously, at least in the early stages of exploration and development.

In NSW, the *Code of Practice for Coal Seam Gas Fracture Stimulation Activities*⁶⁸ applies as a title condition under the *Petroleum (Onshore) Act*. The Code sets out the requirements for a Fracture Stimulation Management Plan, and mandatory requirements and leading practice in relation to various aspects of the Plan.

⁶⁷ Email from V Jackson, DME, to the Inquiry, 1 September 2014

⁶⁸ http://www.nsw.gov.au/sites/default/files/csg-fracturestimulation_sd_v01.pdf

Findings

The Inquiry finds with respect to Fracture Propagation, that:

- the risk of fracture propagation in deep gas shale formations causing hydraulic fracturing fluid, methane or brine to contaminate overlying aquifers is very low, and may be minimised by requiring leading practice in fracture operations, including fracture modelling and real-time and post-fracture monitoring;
- the NTG should consider developing a *Code of Practice for Hydraulic Fracturing Activities*, similar to that of NSW for CSG wells. This should formalise some internal DME regulatory practices that are not adequately covered in the current *Schedule*; and
- the NTG should collaborate with Australian Government, research institutions and industry to support a scientific program to develop a better understanding of stratigraphy, faults, stress distribution and deep hydrogeological processes in NT shale gas basins, which will inform development, regulation and monitoring of unconventional gas extraction.

5.3 Water Use (ToR 7.3)

Water use, and competition for water resources with other current and potential users and environmental requirements, is a significant issue for unconventional gas extraction and hydraulic fracturing. Many submissions to the Inquiry raised water use as an issue, particularly in relation to the NT's strong reliance on ground water for past and future development, the limited water resources in the arid zone where much of the unconventional gas prospects occur, and the perceived lack of transparency and/or adequate regulation in relation to water allocation and management.

There are 35 river basins in the NT, which are grouped into four broad drainage divisions.⁶⁹ Stream flows vary greatly between basins depending on their climate and geomorphology. Flows also vary greatly between seasons and between years; even in the tropical northern basins most streams have no flow over the later dry season months, and very large flows during the wet season. Due to the arid or highly seasonal climate, an estimated 90% of the NT's water needs are supplied by groundwater, with over 30,000 water bores having been drilled. While small-scale groundwater use for stock use and scattered human settlement occurs throughout the

⁶⁹ <http://irm.nt.gov.au/water/surface/basics>

NT, the majority of extraction is concentrated in a few key areas, including Alice Springs and the Darwin rural area (Gough, 2011).

The NT is underlain by numerous aquifers, although groundwater systems are relatively poorly understood due to sparse borehole data and limited groundwater exploration (IAH(NT) submission, pp1-3). Most Top End aquifers are recharged annually during the wet season, and there is a high level of connection in some regions between aquifers and surface water, allowing perennial flow in some rivers and supporting significant mesic ecosystems. Aquifers in the southern, arid NT receive limited annual recharge and ground water in these systems may be thousands of years old. In this region, high-yielding fresh water aquifers are uncommon and therefore of very high value.

In unconventional gas extraction, water is required during drilling of the well, and then for each hydraulic fracture stage. Once the well is complete and producing there are no further water requirements at the well head, unless wells are subsequently re-fractured to stimulate gas flow. The amount of water required to develop a well depends on the number of fracturing stages, the fracturing fluid composition and the local geological conditions. A commonly quoted average water requirement is 15 ML per well (FROGTECH, 2013) with the median volume per well in four USA shale gas plays ranging from 10.6 to 21.5 ML (Beauduy, 2011; Nicot and Scanlon, 2012). For wells in the Cooper Basin, Santos staff described a rule of thumb of 1ML for drilling a well and 1ML for each fracturing stage, although the Beach Energy submission indicated that a typical fracture stimulation requires 1.3 to 1.6ML per treatment. Thus, a vertical well with five fracture stages may require between 5 and 9ML, while a long horizontal well with 15 stages may require between 15 and 24ML. A major shale gas field with 3,000 wells may require 45.6GL of water for fracturing during its life span (NYC DEP, 2009).

Speculative estimates of total water use from unconventional gas extraction should some Australian basins be fully developed (FROGTECH, 2013, p27) were modified for the NT extent of these basins in the International Association of Hydrogeologists (NT Branch) submission (Table 1, p5). Assuming that fairways make up 5% of a basin, wells are spaced at 800m, fracturing each well requires 15ML, and development occurs over 25 years, the total water requirement in four NT basins was projected to be 836GL, or an average of 33.4 GL/year. This compared to an estimated sustainable ground water yield of 2,747 GL/year from these basins, and a current estimated ground water extraction in these basins of 48GL/year.

It is important to understand that these projected water requirements were based on assumptions that imply development over 25 years of an extremely large number of gas wells in the NT- between 10,400 and 17,850 in each basin, and a total of 55,700 in the four basins (IAHNT submission).

Discussions with industry suggest a more realistic development scenario is some 100 production wells drilled and fractured in the NT during the next 7-10 years, an average water requirement (assuming these are all long horizontal wells) of 150-240 ML/yr. If market growth and infrastructure development then allow the ongoing development of up to 100 wells per year (similar to the current level of activity in the Cooper Basin), there may be a longer-term annual water requirement of 1.5-2.4 GL/year for fracturing.

It is important to place the scale of water requirements for hydraulic fracturing in the context of other water uses. Moore (2012) estimated that the water requirement of a shale gas well over a decade was equivalent to that needed to water a single golf course for one month, or to run a 1000 MW coal-fired power plant for 12 hours. The water requirement for hydraulic fracturing within Colorado was estimated to be 0.08% of that State's water resources (citation 52 in Sanders, 2014) and in Texas was estimated to be 0.5% of State water use (citation 53 in Sanders, 2014). One comparison estimated that the amount of water used by all hydraulic fracturing in the USA during 2011 (the peak development year to date) represented 0.1% of total US freshwater withdrawals, and 0.3% of freshwater consumption - and this compared to as much as 0.5% for US golf courses.⁷⁰ In Pennsylvania, USA, shale gas extraction (based on 800 well completions per year) made up 0.1% of consumptive water use (Kenny *et al* 2009), compared to 0.65% for livestock, 1.0% for mining, 1.6% for domestic water supply, 5.5% for public water supply, 5.5% for aquaculture, 8.1% for industry and 67.8% for thermoelectric power.

Water use per unit of energy produced is also very low for shale gas compared to coal or onshore oil, and combined-cycle gas-fire powered plants are also relatively water-efficient (Mielke *et al* 2010). Thus, if shale gas is used to generate electricity at a combined cycle gas plant as a replacement for coal-fired power, the quantity of water consumed per unit of electricity generated could fall by some 80%.

Nevertheless, water use by hydraulic fracturing may be significant and require careful management at a local scale. Although water use for shale gas wells in Texas accounts for less than 1% of total State water use (Nicot and Scanlon 2012),

⁷⁰ <http://theenergycollective.com/jessejenkins/205481/friday-energy-facts-how-much-water-does-fracking-shale-gas-consume>

it accounts for 25% of local water use in Dimmit County and may be affecting ground water flows from the local Carrizo-Wilcon Aquifer.⁷¹

Within the NT, most major users of water rely on extraction from ground water, which is allocated through licences issued under the *Water Act* and based on regional water allocation plans. The Water Allocation Plan for the Ti-Tree Water Control District (north of Alice Springs) allows extraction to the modelled sustainable yield of 13.65 GL/year.⁷² In the Western Davenport Water Control District (south of Tennant Creek), the available allocation of ground water is 44.15 GL/year.⁷³ The Alice Springs Water Resource Strategy licences the extraction of up to 16 GL/year, although this includes the gradual mining of the Amadeus Basin Aquifers for the potable water used by the town of Alice Springs.⁷⁴

In the northern NT, annual recharge from rainfall is much greater and sustainable water extraction volumes may be higher. For example, the maximum extraction limit for the Tindall Aquifer (Katherine) is 35.6 GL/year.⁷⁵ The projection of 1.5-2.4 GL/year of total ground water extraction for fracturing activity for the entire NT falls within the range of maximum water entitlements recently granted to individual properties or enterprises in the Daly/Roper water Control District.⁷⁶

While the projected water requirements for fracturing are small relative to total water availability at NT or regional scales, water may be severely limited at a more local scale. Additionally, a high proportion of the sustainable yield within a catchment or aquifer may already be allocated to other users, or may be required by other potential users in the future.

The ground water resources and hydrogeological systems of large parts of the NT are not well understood (IAHNT submission), which is a potential constraint on an evidence-based approach to water allocation to support the development of a gas extraction industry.

The lack of detailed hydrogeologic data also has implications for safe well design where wells may be drilled through aquifers of a range of depths and quality (Section 5.2). The likely timeframe for the development of the industry within the NT, however, allows for a strategic approach to improving the knowledge base of hydrogeology in potential development areas, as well as building local capacity to

⁷¹ <http://www.texastribune.org/2013/03/08/texas-water-use-fracking-stirs-concerns/>

⁷² http://lrm.nt.gov.au/__data/assets/pdf_file/0018/13851/water_allocation_plan09.pdf

⁷³ http://lrm.nt.gov.au/__data/assets/pdf_file/0010/118369/Western-Davenport-WAP-May-2011-.pdf

⁷⁴ http://lrm.nt.gov.au/water/water_allocation/plans/aswrs

⁷⁵ http://www.lrm.nt.gov.au/water/water_allocation/plans/kwap

⁷⁶ <http://www.lrm.nt.gov.au/water/permits/register>

support the assessment and management of ground water issues. Building the knowledge base will be assisted by ensuring that relevant data collected by industry during exploration and production drilling is made available to appropriate government agencies, and as broadly as possible. The DLRM submission noted that *“DLRM and DME are considering opportunities to obtain additional baseline water resource data, including water quality, in highly prospective basins for oil and gas and will determine how this data may be best recorded and managed for future access”*.

Developments in hydraulic fracturing and water management methods are likely to lead to a reduction in total water use per well and/or a reduction in conflict with other potential users. Flowback water (and subsequently process water) can be reused for subsequent fracturing operations if it can be treated to the required standard in an economically viable way (Section 5.5). Santos staff informed the Inquiry that water recycling was to be introduced as standard practice in fracturing operations in the Moomba field by 2015.

Water that is not potable or suitable for stock use (due to high salinity or other chemical loads) may be usable for fracturing. In particular there is the potential for highly saline water from deep aquifers to be used, avoiding conflict with other potential water users. There are some technical difficulties in mixing fracturing fluid that can meet the required functions using saline water, and this is an area of current research and development, although seawater is already sometimes used for fracturing in offshore production. King (2012) described an example in British Columbia of fracturing operations that used sour brine (high Cl and H₂S) from deep (2440m) formations, in a closed loop system that also minimised water storage requirements.

The feasible salinity of water used for fracturing will be influenced by the chemical composition of the rock formations into which it is injected (eg. saline water may precipitate some compounds and clog the well), so the use of saline water cannot necessarily be mandated. Desalination of salty waste water from the oil and gas industry is in itself a large and growing industry within the USA (King 2012), which is driving innovation and reduction in cost and energy use of water processing.⁷⁷

Another area of development is waterless fracturing, using gels and carbon dioxide or nitrogen gas foams. There are potential advantages in these techniques where

⁷⁷ <http://www.forbes.com/sites/ericagies/2012/06/04/company-aims-to-desalinate-fracking-water-a-1-6-billion-market/>

they result in less return to the surface of salts, heavy metals or NORMs (see Section 5.5) from the target rock formations (RSRAE, 2012).

Regulation and Monitoring

Water in the NT is the property of the Crown and the NTG's statutory responsibility for assessing, monitoring and allocating water resources are established under the *Water Act*.

Water extraction licences are issued by a Controller of Water Resources appointed by the Minister, and water allocation and planning is administered by the DLRM, which is also responsible for assessment of ground and surface water resources.

The *Water Act* provides for Water Allocation Plans to be developed within Water Control Districts, the latter being declared for areas where there are competing demands for water resources. There are currently eight water control districts in the NT⁷⁸, with four declared water allocation plans and five in progress.⁷⁹ Outside the water control districts there is considered to be only limited demand for water (typically for stock purposes on pastoral properties), although water extraction other than for domestic or stock use requires a licence under the *Water Act*.

Water allocation planning and water extraction licencing in the NT is guided by a water allocation planning framework which accords with the National Water Initiative. Precautionary water allocation rules allow a maximum of 20% of surface water flow or annual ground water recharge in the northern NT to be allocated for consumptive use; and in the arid zone a maximum of 5% of surface water flow and a maximum ground water extraction of 80% of total initial aquifer storage over a period of 100 years.

However, under Section 7, many parts of the *Water Act* do not apply to mining or petroleum activity, including those relating to extraction of surface water (Part 5) or groundwater (Part 6). Water resource protection and use associated with mining and petroleum activities are administered by DME under the *Mineral Titles Act*, *Mining Management Act* and the *Petroleum Act*.

In relation to gas extraction and hydraulic fracturing, the *Petroleum Act* allows for exclusive rights to carry out operations and execute works, including use of water for domestic use and for any purpose in connection with an approved technical work program and other exploration as part of a granted Exploration Permit or Licence.

⁷⁸ http://www.lrm.nt.gov.au/water/water_allocation/maps

⁷⁹ Ibid.

The *Schedule of Onshore Petroleum Requirements (2012)* and DME Guidelines (detailed in the DME submission) require that EPs are submitted for each activity associated with exploration and development, including hydraulic fracturing. The DME submission acknowledges that “*the current regulatory framework does not explicitly address water use*”, something that is to be addressed in new Regulations which are under development. The need to describe water use may be implied by a requirement in the *Schedule* that applications should include “*a statement of proposed environmental protection*”. The DME internal Checklist for assessment of Environment Plans (DME submission, Attachment D) suggests that the operator is required to address water use issues including anticipated consumption, source, ground water salinities, provision for independent ground water monitoring and frequency of testing.

Environment Plans for onshore gas projects are submitted to the NT EPA for review, which may in turn seek comment from relevant agencies including DLRM (if NT EPA believes that they should be assessed as meeting the requirements for a Notice of Intent). However, onshore petroleum projects have only been routinely referred to NT EPA since the end of 2013.

DME may also separately determine that project applications or EPs need to be provided to other government agencies, particularly DLRM, for comment. The DLRM submission noted that “*A key concern is that DME’s regulatory process considers all relevant environmental issues including the hydrogeology of fresh water aquifers, the planned demand for hydraulic fracturing and the source of that water*”. That submission also stated that EPs should include a hydrogeological investigation of known and potential aquifers in the target area to inform the design of operations and monitoring.

In relation to water use for oil and gas wells, the DLRM submission noted that this “*water demand is included in water allocations within sustainable yield limits in water allocation plans, where appropriate*” and “*The information is also available for collaboration between DLRM and DME when making water extraction authorisation decisions outside water planning areas*”.

Administrative arrangements spanning the *Water Act*, *Mining Management Act* and *Petroleum Act* are covered by a Memorandum of Understanding (MOU) between DLRM and DME, which is currently under review.

The 2012 Turner review of NT onshore petroleum legislation recommended that “*regard should be given to the implementation of a separate, overarching*

*environmental protection Act, or the application of current water, waste management and pollution control legislation to petroleum activities”.*⁸⁰

In relation to the allocation and regulation of water resources, the Turner review also recommended that “*Legislative provisions rather than soft law provisions should be adopted for water resource allocations to all users, including those undertaking petroleum or mining operations, to ensure that all stakeholders have adequate and equitable access to water resources*”.

Submissions to the Inquiry similarly recommended that petroleum activities should not be excluded from the *Water Act*, to ensure that they were properly and equitably integrated into the water allocation and licencing process.

Administrative arrangements should still allow for a one-stop-shop model for operators should the *Water Act* apply to petroleum activities.

Findings

The Inquiry finds with respect to Water Use, that:

- unconventional gas extraction has water requirements for drilling and hydraulic fracturing that are small in the context of many other licenced water uses, but which need to be managed carefully to ensure sustainability at a local or catchment/aquifer scale. Conflict with other water users can be reduced by the use of saline ground water or recycled water where feasible;
- water allocation to gas extraction activities including hydraulic fracturing should be transparent, based on sound knowledge of the sustainable yields of aquifers or surface waters, and balanced with the requirements of other water users and environmental benefit. Within the NT, this is probably best done under the *Water Act*, and where possible within the context of regional water allocation plans;
- the NTG, with the support of industry, should improve knowledge of aquifers and ground water systems in regions where current knowledge is poor and where development of the gas extraction industry is most likely to occur, in order to support evidence-based water allocation as the industry develops over the next two decades. Relevant data collected by industry during exploration and extraction should contribute to building this knowledge base; and
- the NTG and industry should work together to develop, promote and mandate leading practice in water use for hydraulic fracturing, including recycling of

⁸⁰ http://www.nt.gov.au/d/Minerals_Energy/?header=Legislation%20Review%20-%20Petroleum

flowback water and the preferential use for fracturing fluid of ground water that is unsuitable for human, stock or other beneficial use.

5.4 Chemical Use (ToR 7.4)

Chemical use during hydraulic fracturing was frequently raised with the Inquiry, particularly in relation to toxicity of chemicals used in the fracturing operation; potential contamination of ground water and/or surface water systems with these chemicals; and lack of transparency or accessible information about the chemicals used in each fracturing operation.

Hydraulic fracturing fluids are usually water-based, with the addition of a “proppant” to keep fractures open and a potentially large range of chemical additives that have specific roles in the fracturing process (King, 2012, p33-34; ALL Consulting, 2012, pp16-24). The proportion of these components in fracturing fluid varies, but is typically 90-98% water, 2-10% proppant and less than 1% chemical additives.

Proppants, which are usually sand, resin-coated sand, sintered bauxite or other ceramics, have a physical rather than chemical role in ensuring small fractures in the target rock strata remain open for fluid and gas flow. The grain size and strength of the proppant is selected to match the physical properties and pressure of the target strata to be fractured.

Chemical additives may include acids, biocides, scale inhibitors, friction reducers, gelling agents and surfactants, each with a specific role in optimising outcomes from the fracturing process (see Table 5-1 on the next page). A friction reducer may be used in “slickwater” to allow injection of a greater fluid volume in a given time; alternatively gels and cross-linked gels may be used so the fluid can carry more proppant and to reduce water use.

The composition of the fracturing fluid is tailored to suit site-specific conditions of the well, and may be varied throughout the fracturing operation to perform specific tasks (a useful description of this process was given in the Beach Energy submission). The Beach Energy submission also gives an example of chemical concentrations in fracturing fluid used in the Holdfast-1 well in the Cooper Basin in South Australia (Beach, 2012).

Table 5-1: Hydraulic fracturing fluid additives (ACOLA, 2013, p57; USDOE, 2009)

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric Acid or Muriatic Acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive by products	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium Persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion inhibitor	N, n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction reducer	Polyacrylamide Mineral oil	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner Make up remover, laxatives, candy
Gel	Guar gum or hydroxyethyl	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron control	Citric Acid	Prevents precipitation of metal oxides	Food additive, flavouring in food and beverages; lemon juice ~ 7% Citric Acid
KCI	Potassium Chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium Bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or Potassium Carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale inhibitor	Ethylene Glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair colour

A historical area of dispute has been the extent of public disclosure of the composition of fracturing fluids with, for example, exemption being granted from full disclosure to even the US EPA during the boom of the industry in the USA in the 1980 and 90s. More recently, there has been a strong trend towards voluntary or enforced public disclosure, particularly through development of the FracFocus website established in 2011 by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission.⁸¹ This site now contains details for some 80,000 hydraulically fractured well sites in the USA, and is used by a number of USA States as the official means for chemical disclosure. As CCST (2014) noted, however, voluntary submitted data on FracFocus was useful but needed to be interpreted carefully as it was not required to be either complete or accurate.

Halliburton (one of the major companies providing hydraulic fracturing services) discloses the typical composition of additives in their fracturing fluids, including in Australia, with links to the Material Safety Data Sheets (MSDS) for each chemical.⁸² Halliburton staff informed the Inquiry that their preferred approach was to disclose the overall chemical composition of the fracturing fluid, rather than the composition of each constituent individually, as some of the latter are proprietary products and their composition is commercially valuable information. Schlumberger (another major industry service company) promotes the use of their “OpenFRAC” hydraulic fracturing additive systems that includes full disclosure of additive components.⁸³

Following the fracturing process, between 25% and 75% of the fracturing fluid, may be expected to return to the surface during initial flowback (and possibly the subsequent production phase), where it is captured and processed (see Section 5.5) (RSRAE, 2012; King, 2010). The remaining injected fluid remains trapped in the rock strata deep underground. A smaller proportion of some of the injected chemicals - less than 40% for polymers and 20% for other chemicals (King, 2012; Friedman, 1986) will return to the surface as they are consumed or modified during the fracturing operation, or held within the rock strata. For example, acid is spent within a short distance of the entry point and does not return as acid to the surface; biocides are spent and degrade; surfactants and corrosion inhibitors adsorb on to rock or steel surfaces.

There has been particular concern about additives containing volatile aromatic compounds known as BTEX (benzene, toluene, ethylbenzene and xylene) and the

⁸¹ <http://fracfocus.org/welcome>

⁸² http://www.halliburton.com/public/projects/pubsdata/Hydraulic_Fracturing/fluids_disclosure.html

⁸³ http://www.slb.com/services/completions/stimulation/unconventional_gas_stimulation/openfrac_hydraulic_fracturing_fluids.aspx

use of such compounds during fracturing is now banned in most Australian jurisdictions (including the NT).

There are conflicting views on the safety or potential toxicity of fracturing fluid. Many of the chemicals used in fracturing fluids are found in processed food, in a range of household products, or routinely in many industries (Table 5.4). For example, the common gelling agent is guar gum, which is used in the food industry to improve the texture of ice cream and baked goods. Halliburton advertises a fracturing fluid system (“CleanStim”) which contains only ingredients sourced from the food industry. Additionally, most chemical constituents are highly diluted within the fracking fluid, typically individually comprising less than 0.01% by volume.

Conversely, in their submission to the Inquiry, the Lock the Gate Alliance claimed that *“fracking compounds used in Australia have been shown to include many hazardous substances, including carcinogens, neurotoxins, irritants/sensitisers, reproductive toxins and endocrine disruptors”*.

A review of chemicals reported for use in “well stimulation” in the USA (CCST 2014, p15) concluded that most are of low toxicity or non-toxic, but a few present concerns for acute toxicity. In common with some other reviews, CCST (2014) noted that there is a lack of data on the potential risk from chronic exposure to chemicals used in fracture stimulation, or on interactive or additive effects of the chemical combination.

The Australian Government has commissioned a project to undertake an independent assessment of chemicals used in drilling and hydraulic fracturing associated with Coal Seam Gas extraction, to be undertaken jointly by National Industrial Chemicals Notification and Assessment Scheme (NICNAS), CSIRO, Commonwealth Department of the Environment and Geoscience Australia.⁸⁴ In addition to assessing chemicals used in fracturing, the project will assess environmental risks from naturally occurring contaminants that may be released as a result of gas extraction.

Most recent reviews conclude that risks to water quality and health risks associated with fracturing fluid chemicals may be minimised by strictly managed storage and handling (as per MSDS), strict controls to ensure well integrity (see Section 5.2), and stringent management of waste water after it is returned to the surface (Section 5.5).

⁸⁴ <http://www.nicnas.gov.au/communications/issues/fracking-hydraulic-fracturing-coal-seam-gas-extraction/information-sheet>

The greatest environmental risk appears to be surface contamination from spills or accidents during the transport and storage of large quantities of chemicals in their concentrated form prior to fracturing. The full fracturing of a well may involve up to 75,000 litres of chemical and 1000 tonnes of proppant, as well as a large quantity of diesel fuel for pumps. Best practice management includes bunding the drill pad, use of spill mats below chemical storage sites and pipework, and appropriate spill response and clean-up plans. These chemical handling controls are common to many mining and other industrial processes, with well-developed regulation and guidelines, and the risks are not unique to unconventional gas extraction or hydraulic fracturing.

Regulation and Monitoring

There is no legislation or regulation in the NT explicitly governing the composition or disclosure of composition of fracturing fluid, and the *Schedule of Onshore Petroleum Exploration and Production Requirements 2012* does not cover chemical use (other than reference to well control properties of drilling fluid). The DME Checklist for Environment Plan assessment (DME submission, Attachment D, p117) requires “disclosure of MSDSs or List Of Chemicals to be used” to be included in the EP; and the DME Guidelines for Environmental Plan requirements states that the list of chemicals “are to be made available for public record on DME’s website”.

The DME submission indicated that “*DME is currently working on a chemical disclosure factsheet for hydraulic fracturing, and will also be proposing that regulation of chemical use be addressed explicitly*”. As of October 2014, the DME Chemical List Disclosure webpage showed seven wells, three from 2012 and four from 2014.⁸⁵ These disclosures differ in format and content - in some cases they are a collation of the MSDS for the chemicals used and in other cases detail the concentration of additives and the mass fraction of individual chemical components, with their CAS (Chemical Abstracts Service) number.

Other Australian jurisdictions have requirements either in legislation or policy for disclosure of the composition of hydraulic fracturing fluid:

- NSW: Code of Practice for Fracture Stimulation Activities (2012);⁸⁶
- Qld: Petroleum and Other Legislation Amendment Regulation (No 1) 2011,⁸⁷ and

⁸⁵ http://www.nt.gov.au/d/Minerals_Energy/?header=Chemicals%20Disclosure%20List

⁸⁶ http://www.nsw.gov.au/sites/default/files/csg-fracturestimulation_sd_v01.pdf

⁸⁷ <https://www.legislation.qld.gov.au/LEGISLTN/SLS/2011/11SL035.pdf>

- WA: Petroleum and Geothermal Energy Resources (Environment) Regulations 2012.⁸⁸

Regulatory arrangements in Australia for industrial chemicals more broadly are complex and most chemical additives used in hydraulic fracturing have not yet been specifically assessed by the National Industrial Chemicals Notification and Assessment Scheme for their intended use (DoE, 2014, pp49-50).

Chemical disclosure laws within the USA were reviewed by Murrill and Vann (2012) and vary widely between States, including in the timeframe of disclosure requirements and protection of trade secrets. In 2013, 18 states required fracturing chemicals disclosure and 11 of those states (Colorado, Louisiana, Mississippi, Montana, North Dakota, Ohio, Oklahoma, Pennsylvania, South Dakota, Texas and Utah) direct or allow well operators and service companies to report chemical use to FracFocus. Konshnik *et al* (2013) were critical of FracFocus as a regulatory compliance tool due to weaknesses around timely disclosure, lack of minimum reporting standards to match State disclosure requirements and inconsistent trade secret assertions.

The *National Harmonised Regulatory Framework for Natural Gas from Coal Seams* noted that full disclosure of chemicals used in gas production would increase public confidence in the industry, recommended full disclosure as part of leading practice, and listed recommended elements of disclosed information (SCER, 2013, p64). The SCER Framework also noted disclosed information can be structured in a way that specific combinations or formulas for proprietary products cannot be determined.

The APPEA submission noted that the industry strongly supports transparent practices and encourages consideration of a FracFocus style website for the NT, which could provide a one-stop shop for information on areas being explored for shale and tight gas and the chemicals used in each well. The APPEA submission notes the example of the Queensland Coal Seam Gas Globe⁸⁹ which provides publicly accessible information on exploration and extraction activities.

⁸⁸ <http://www.dmp.wa.gov.au/documents/ENV-PEB-178.pdf>

⁸⁹ The Coal Seam Gas Globe (<https://www.dnrm.qld.gov.au/mapping-data/queensland-globe/using-coal-seam-gas-globe>) is an online tool implemented inside the Google Earth™ application. It allows users, including the public, to view the location of gas wells, exploration and petroleum leases and licences, water bores and water monitoring bores.

Findings

The Inquiry finds with respect to Chemical Use, that:

- chemicals used during hydraulic fracturing generally pose a low environmental risk, providing that leading practice is applied to minimising surface spills and managing flowback water after fracturing. Public concern about chemical use will be reduced by a transparent, full disclosure policy;
- the NTG should formalise the ban on BTEX chemical use in hydraulic fracturing; implement a process to develop and periodically review a list of other prohibited chemicals as further information about environmental and health risks is available; and work with industry to promote leading practice in minimising the use of chemical additives; and
- the NTG should formalise the requirement for full public disclosure of chemicals used in fracturing fluid and develop a standard format for such disclosure in accordance with the SECR recommendations; and
- public transparency could be improved through making information available through a purpose-designed Web portal that maps the location of wells and fracturing events, and displays chemical information in formats that are accessible to the general public.

5.5 Disposal and Treatment of Waste Water and Drilling Muds (ToR 7.5)

Waste water produced during unconventional gas activities is a potential source of environmental contamination, particularly of surface water and shallow ground water, and requires careful management. Waste water management is an issue common to conventional oil and gas extraction and other forms of mining and industrial activity, so many of the same principles and practices apply, although there are some features of waste water specific to hydraulic fracturing and deep shale gas wells.

In unconventional gas extraction, waste water is generated during drilling (as drilling “mud”) and particularly during the “flowback” period following hydraulic fracturing. During the production phase, some waste water will also be extracted during gas processing. Water inputs and chemical use in hydraulic fracturing are described in Sections 5.3 and 5.4.

Drilling is undertaken using a water-based mud (WBM) to lubricate the drill bit, carry cuttings to the surface and control pressure within the well. Fresh water is the

base fluid with bentonite (finely ground clays) added as a viscosifier. As the well is drilled deeper, weighting agents are added to offset the formations pressures in the well. When the mud returns to the surface, cuttings are separated, filtered out and stored and the mud returned to the mud storage tank for reuse. Depending on the source of the cuttings and their oil, salt or radioactive content, they may be disposed of in a landfill or transported to a waste disposal facility. After drilling is complete, the residual mud is dewatered in an evaporation pit and generally buried on-site or spread in land-farms.

Following hydraulic fracturing, between 25% and 75% of the fracturing fluid flows back to the surface, mixed with formation water and methane. The composition of fracturing fluid was described in Section 5.4, although some of these components are spent or denatured during the fracturing process. Flowback composition is initially similar to fracturing fluid and then is increasingly dominated by formation water. The formation water is usually highly saline (eg 35,000 - 150,000 ppm total dissolved solids) and contains minerals and organic compounds from the shale formation (eg. barium, bromine, strontium), which may include some heavy metals and naturally occurring radioactive material (NORM). The latter include isotopes of potassium, thorium and uranium, as well as decay products such as radon and radium. Light condensate may be associated with gas and some naturally occurring hydrocarbon compounds including BTEX may be present in recovered fluids. During flowback, separators may be used to separate condensate and gas from the waste water, particularly after the early clean-out stage (see Section 5.6).

Flowback rates may be 500-1000 litres per minute for a few hours, dropping to 160,000 litres per day within 24 hours, decreasing over several days to 50,000 litres per day (ACOLA, 2013, p59). For production wells, flowback may continue for 10-15 days before the well is connected to the production pipeline. Small volumes of formation water are returned throughout the production period.

Historic practice (e.g. in North America) has been to temporarily store waste water in open pits lined with clay or an impermeable membrane adjacent to the well, but there is now a trend to (and in some American jurisdictions a regulatory requirement for) storage in sealed tanks. Waste water may be treated (usually to reduce salinity and remove undesirable components such as barium and microorganisms) and reused in subsequent fracturing stages (King, 2012, pp 39-43). A large proportion of produced water from shale gas wells in the USA is ultimately reinjected into the ground, either into conventional oil and gas reservoirs in order to maintain reservoir pressure, or into deep disposal wells in porous and permeable rock formations (Kell, 2011; King, 2012). Waste may also be dewatered in

evaporation ponds and the sludge moved to waste treatment facilities; or the waste water piped or trucked to a treatment plant.

Flowback water from unconventional gas wells cannot generally be treated by typical municipal waste water treatment plants due to high salinity and the possible presence of NORMs (CCA, 2014, p94). Other treatment methods that may allow treated water to be discharged have high costs (although these have been predicted to decline as demand increases and technology improves) and hence deep-well injection has been the preferred disposal option in North America when geology is suitable. There are risks with deep disposal of waste water including ground water contamination and induced seismicity, which can be mitigated by a detailed understanding of the stratigraphy and hydraulic properties of the formations used, and low injection pressures and rates (CCA, 2014, p95).

Potential incidents that could lead to contamination of surrounding ecosystems (particularly aquatic systems) by drilling and flowback fluids are described by Broderick *et al* (2011) and summarised in ACOLA (2013, p119) and include:

- spillage, overflow or water ingress or leaching from cuttings/mud pits;
- spillage of flowback fluids during transfer to storage;
- loss of containment of stored flowback fluids;
- spillage of flowback fluid during transfer from storage to tankers for transport; and
- spillage of flowback fluid during transport to waste water treatment works.

The Santos submission (pp52-53) describes some practices used to minimise risk from waste water. Flow-back pits are lined with UV-stabilised high-density polyethylene liners, and earthen bunds are built around flow-back pits to prevent surface water ingress. During operations, tanks and ponds are inspected at least daily for potential breaches or leaks and repaired as required. A minimum of 300mm freeboard in tanks and pits is maintained to prevent overflow associated with flooding or surface water ingress. Emergency shutdown systems are installed on equipment to prevent uncontrolled release of flowback water or other chemicals, and there is routine inspection of flow-back lines, connections, high pressure equipment and trip systems. Where heavy rainfall or floodwaters pose a risk, produced fluids are removed from pits and transferred to tanks or satellite facilities not subject to flood risk. In Santos' current NT operations, produced fluids are evaporated in lined pond systems. Where safe, solid residue is treated at land farms. Licenced waste management contractors are used to transport other waste material to approved waste management facilities (usually to Adelaide) for disposal.

Santos indicated that they are undertaking stage-wise improvements towards replacement of lined pits with tanks, including specially designed flowback tanks and pit-less flowback operations; and increasing the extent of recycling of flowback fluid in hydraulic fracturing operations (Santos submission, p39).

The Beach Energy submission (section 1.9) recognises that alternative strategies to evaporation for waste water management may be required in higher rainfall areas of the NT (such as the Bonaparte Basin). Options may include trucking of recovered fluid to a disposal facility; on-site treatment to concentrate brine for trucking to a disposal facility; or reinjection of concentrated brine, or all recovered fluids, into a saline, unaccessed aquifer or the target reservoir. Beach Energy suggested the appropriate solution would be determined during the environmental risk assessment process for future projects.

The IAH(NT) submission notes that safe containment, treatment and disposal of waste water at the surface is particularly difficult in the monsoonal north; and that one problem with trying to manage containment dams in high rainfall areas is that the NT has no dam safety regulations. The IAH(NT) submission recommends that waste water storage should be in lined ponds with a flood immunity of 1,000 years.

Treatment of waste water from unconventional gas operations in monsoonal NT could be informed by leading practice from the mining industry, noting also prominent examples of controversial wet-season release of water from storage ponds.

Shale gas differs significantly from coal seam gas, in that the volume of produced water from shale gas is much lower and of poorer quality than from CSG production. Therefore the (high-profile) water management issues associated with CSG production do not necessarily apply to shale gas, but neither are some of the reuse and recycling options developed for CSG (such as beneficial use priorities under the *Queensland Coal Seam Gas Water Management Policy 2012*) applicable to shale gas.

Regulation and Monitoring

In the NT, waste management and pollution are generally regulated under the *Waste Management and Pollution Control Act*, and pollution of water is also regulated under the *Water Act*. However, these Acts do not apply to mining or petroleum activities where contamination or waste is confined within the land on which the activity is being carried out, so that on-site waste water management for unconventional gas extraction is mostly regulated under the *Petroleum Act*. The

2012 Hunter review of NT onshore petroleum legislation recommended that “regard should be given to the implementation of a separate, overarching environmental protection Act, or the application of current water, waste management and pollution control legislation to petroleum activities”.⁹⁰

The *Schedule of Onshore Petroleum Requirements* (2012) under the *Petroleum Act* does not specifically address the management of flowback water from hydraulic fracturing. The DME submission (p23) states that in order to obtain project approval, the operator’s Environment Plan must include details relating to the disposal and treatment of waste water and drilling muds. The internal DME checklist for the Environment Plan assessment (DME submission, Attachment D, pp110-124) requires that the EP must address the disposal method for all wastes, including the end delivery point for all produced fluids; identify procedures for safe handling and disposal of produced and flowback fluids; and have a Waste Management Plan in place.

As described in other sections, the Environment Plan is referred to the NT EPA and other government agencies for comment. The DME submission (p23) also notes that sites visits and the assessment of the completed rehabilitation plan provide a compliance framework.

Regulation of waste water management in Northern American jurisdictions is generally tending to impose greater restriction on the use of open ponds for storage of waste water and/or more specific guidance on the minimum standard for pond construction. For example, the *Illinois Hydraulic Fracturing Regulator Act* includes a prohibition of open-air ponds for waste water storage.⁹¹ In British Columbia, only slickwater fracture fluid returns can be stored in open tanks or lined ponds; all other returned fracture fluids must be stored in closed-top tanks (NSIRP, 2014, pp180-182).

The American Petroleum Institute (API 2010) documents industry best-practice standards for water management, including waste water treatment.⁹² The State Review of Oil and Natural Gas Environmental Regulations also publishes guidelines that include waste management options and practices (STRONGER, 2014).⁹³

⁹⁰ http://www.nt.gov.au/d/Minerals_Energy/?header=Legislation%20Review%20-%20Petroleum

⁹¹ <http://www.dnr.illinois.gov/OilandGas/Pages/HydraulicFracturingRegulatoryAct.aspx>

⁹² http://www.api.org/~media/Files/Policy/Exploration/Hydraulic_Fracturing_InfoSheet.pdf

⁹³ <http://www.strongerinc.org/stronger-guidelines>

Findings

The Inquiry finds that with regard to Waste Water, that:

- waste water management issues are similar to many other mining and industrial processes, although treatment of produced water following fracturing may have some unique elements. On-site treatment and recycling are desirable where possible, but the use of reinjection for waste water disposal will require further investigation to test whether it can be safely applied in Australia.
- NTG and industry should work together to develop a common understanding of “leading practice” for the management of waste water from unconventional gas activities. This may include developing guidance for preferred approaches in different biomes and climate regimes including, for example, the acceptable risk level for extreme rainfall or flood events;
- NTG should consider making on-site petroleum activities subject to the *Waste Management and Pollution Control Act*, with appropriate arrangements between leading and co-regulatory agencies to maintain a one-stop-shop approach for industry;
- NTG should work with industry and research agencies to support the development of improved technology for treatment and recycling of waste water from unconventional gas extraction, and promote or mandate recycling for hydraulic fracturing where feasible; and
- as the NT gas industry develops, the NTG should investigate whether economic viability may be enhanced by the development of suitable licenced waste treatment facilities within the Territory.

5.6 Fugitive Emissions (ToR 7.6)

“Fugitive emissions” are considered to include all greenhouse gas emissions from exploration, production, processing, transport and distribution of natural gas (IPCC, 2006). Greenhouse gas (GHG) emissions can occur from multiple sources within these processes, but this section focuses on the leakage of natural gas (methane) to the atmosphere during well completion, production and after well decommissioning.

Being a powerful greenhouse gas, methane is of particular concern. In Australia, methane has been assigned a global warming potential (GWP) of 25 applicable for a 100-year period (DCCEE 2010)⁹⁴, although the IPCC Fifth Report (2013) suggests

⁹⁴ This means that a certain mass of methane will produce the same warming effect as 25 times that mass of CO₂, with “CO₂ equivalents” being the standard reporting metric.

a GWP of 28. Some analysts suggest that warming impacts should be considered over a 20 year period, in which case methane would have a GWP of 72-84.

Following fracturing, and before the well is connected to production pipelines, there is a “flowback” period (usually 3-10 days) when hydraulic fluid and produced water flow back up the well and are captured and processed (Section 5.5). There can also be a significant amount of methane in this flowback, which may be managed through:

- “venting” the methane into the atmosphere;
- “flaring” by burning the gas on site; or
- capturing the gas for sale, or reinjection into a reservoir (known as “green completion”).⁹⁵

Flaring greatly reduces greenhouse gas emissions compared to venting as it converts methane to carbon dioxide. However, flaring may also release volatile organic compounds (VOC), nitrous oxide and black carbon, which can have human health risks (CCA, 2014, pp113-115). Leading practice has led to a move from venting to “open” flaring, to flaring using a “completion combustion” device, to an increasing proportion of gas captured during green completion. In the USA, current practice suggests about 70% of emissions being captured, 15% flared and 15% vented (O’Sullivan and Paltsev, 2012) or now as high as 90% green completions (CCA, 2014, p105). Green completion is not yet common practice in Australia, and ACOLA (2013, Appendix 2) assumed a likely case for Australia of 10% venting and 90% flaring.

During the production phase, and also following decommissioning, there may be methane leakage between the surface casing and production casing (SCVF - surface casing vent flow), which may come from gassy strata at intermediate depth zones, or biogenic gas from shallow zones (NSIRP, 2014, p205). Some gas may also migrate to the surface outside the production casing and around the conductor casing (Watson and Bachu, 2009; Dusseault *et al*, 2014). As described in Section 5.2, Watson and Bachu (2009) found gas migration leakage in 0.6% of wells and surface-casing vent-flow in 3.9% of wells in Alberta, Canada, although this percentage would be expected to be lower in modern wells with multiple casing and sound cementing.

Some leakage of gas occurs during transport and processing (Alvaraez *et al*, 2012) and other greenhouse gases (notably carbon dioxide) may be extracted from methane during processing (ACOLA, 2013, p142; Jiang *et al*, 2011). Where carbon

⁹⁵ http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf

dioxide concentrations of production gas are high, sequestration of the extracted carbon dioxide may be desirable.

Studies have estimated the amount of methane “leakage”, particularly during flowback, either as a proportion of gas production or as a contribution to total greenhouse gas emissions. Howarth *et al* (2011) estimated that between 3.6% and 7.9% of methane from shale gas production escapes to the atmosphere through venting and leaks over the lifetime of a well, including 1.9% during well completion - although aspects of this study have been substantially criticised (Cathles *et al*, 2012; O’Sullivan and Paltsev, 2012; ACOLA, 2013, Appendix 2). O’Sullivan and Paltsev (2012) used data from some 2000 horizontal shale gas wells completed in five plays in the USA during 2010 to estimate fugitive emissions as between 0.39% and 0.99% of total production. Direct field measurements by Allen *et al* (2013) including production, well completion, unloading and workover sites in the USA gave an estimate for average total methane leakage of 0.42% of gas produced.

Methane leakage rates in natural gas production and processing systems (post well completion flowback) have been variously estimated at 3.5% of total lifetime production (Venkatesh *et al*, 2011); 1.7% to 6.0% (Howarth *et al*, 2011); 1.5% of total production for the USA and 0.4% for Canada (cited in CCA, 2014, p108); and between 1.7% and 7.7% for the Denver-Julesburg Basin, Colorado (Petron *et al*, 2012). Other recent “top-down” studies of ambient atmospheric methane levels in the USA have shown relatively high emission rates attributed to oil and gas production (Karion *et al*, 2013; Miller *et al*, 2013). The variation in estimated emissions between studies may partly reflect the extent to which they incorporated all potential sources of methane emissions.

Recently, methane emissions were measured at 43 CSG wells in NSW and Queensland (Day *et al*, 2014). Emissions were small and were mostly attributable to venting of gas-powered pneumatic devices, equipment leaks and engine exhaust; although this study did not sample well completion activities. Maher *et al* (2014) measured methane and carbon dioxide concentrations in the atmosphere of a large coal seam gas field in southern Queensland and found a “widespread enrichment” of methane and carbon dioxide within the production gas field, compared to outside. However, the lack of pre-gas production baseline studies means that elevated gas concentrations cannot be unequivocally attributed to coal seam gas mining.

Comprehensive assessment of the GHG emissions for shale gas require consideration of all sources of emissions in each stage of exploration, well completion, production, processing, distribution and consumption - referred to as

“well to burner” or life-cycle analysis. Such analyses suggest that life-cycle GHG emissions for electricity generation from unconventional natural gas are close to those for conventional gas and significantly lower than those from coal and oil (Logan *et al*, 2012; CHC, 2014, pp110-111; ACOLA, 2013, pp144-145), partly because gas-fired electricity generation (especially in combined cycle gas turbine plants) is significantly more efficient than coal-fired generation.

One exception to these findings is the analysis of Howarth *et al* (2011) that calculated life-cycle emissions from unconventional gas as being higher than those from coal. That analysis has, however, been criticised (e.g. Cathles *et al*, 2012) because it overestimated fugitive emissions and undervalued the contribution of green completions, based the comparison on heat generation of fuels rather than electricity generation, and adopted a short residence time of methane in the atmosphere. This debate is important in illustrating that accurately accounting for fugitive emissions, due to the large GWP of methane, is a key element of life-cycle GHG accounting.

Shale gas also contains varying amounts of CO₂ which is removed, and often vented, during processing. This may also need to be accounted for during life-cycle GHG analyses (ACOLA, 2013, p148).

The ACOLA Report (2013, pp147-151) includes a useful discussion of the potential contribution of increased shale gas production to a reduction in Australian GHG emissions.

Regulation and Monitoring

In the USA, the US EPA regulates certain aspects of natural gas development under the *Clean Air Act*. From 2015, the EPA will require all unconventional gas wells to capture natural gas and condensate during completion and make it available for use or sale, in order to greatly reduce VOC emissions. As an interim measure between 2011 and 2014, there is a requirement to reduce VOC emissions by flaring using completions combustion devices or green completions.⁹⁶ Moreover, some USA jurisdictions do not allow venting or mandate reduced emissions completion⁹⁷ and, in Canada, both British Columbia and Alberta prohibit venting in most circumstances and have targets to reduce or eliminate routine flaring.

Under the *Australian National Greenhouse Gas Accounts*, aggregated industry data is reported on venting, flaring and fugitive emissions for natural gas. Fugitive

⁹⁶ <http://www.epa.gov/airquality/oilandgas/pdfs/20120417summarywellsites.pdf>

⁹⁷ http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/Comparison_Table_CSSD-Colorado-PA-Ohio-WV-EPA-Air_Standards-2014-05-28-1530.pdf

emissions are estimated by companies using methods specified by the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*, which do not differentiate between conventional and unconventional gas production. Unfortunately, this reporting approach does not provide much incentive to measure accurately or reduce fugitive emissions from well completion in unconventional gas wells (ACOLA, 2013, p146).

Flaring is standard industry practice in Australia (e.g. Santos submission, p55). Adoption of green completion is not widespread, partly because it is not yet seen as cost-effective, particularly in new fields where there is little existing production pipeline infrastructure.

The DME submission states that in the NT, for both exploration and production activities, fugitive emissions need to be addressed in the operator's Environment Plan as part of the project approval process. Some clauses in the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) relate to fugitive emissions (526, 527, 531, 540), including specifying that any significant volume of gas that is vented shall be burnt through a flare system (Clause 527). For production activities, Clause 619 of the *Schedule* requires that gas will not be flared or vented without approval, and this would be addressed in the Operator's Reservoir Management Plan. There appear to be no specific requirements for monitoring fugitive emissions, but the DME submission suggests that suspension or abandonment of wells in accordance with their approvals will ensure subsequent emissions are negligible.

In recognition of landowner and community concern about increasing numbers of unmanned CSG wells and associated pipelines, the Queensland Government has implemented a *Code of Practice for Coal Seam Gas Well Head Emissions Detection and Reporting*. This is intended to provide a consistent industry approach to leak testing, reporting and remediation, with compliance monitoring by the Petroleum and Gas Inspectorate.⁹⁸

Findings

The Inquiry finds with respect to Fugitive Emissions, that:

- accurate monitoring of, and accounting for, fugitive emissions during unconventional gas production - including during well completion and following well closure - are critical to understanding life-cycle greenhouse gas emissions.

⁹⁸ http://mines.industry.qld.gov.au/assets/petroleum-pdf/code_practice_well_leak_class.pdf

Reduced emission completions (“green completions”) will contribute to minimising fugitive emissions;

- the NTG should mandate the use of flaring as the minimum standard for managing fugitive emissions during well completion following hydraulic fracturing, and work with industry and other Australian jurisdictions to promote the uptake of “green completion”; and
- the NTG and industry within the NT should encourage and cooperate with studies that seek to improve atmospheric monitoring of fugitive methane emissions, including pre-development baseline measurements.

5.7 Noise (ToR 7.7)

Noise is one of the “nuisance” impacts associated with unconventional gas operations, that may affect human health and/or pose an ecological risk to sensitive wildlife.

Hydraulic fracturing and drilling noise levels can exceed 64dB at 75m from the site and an average 40dB at 1.5km away (NSIRP, 2014, p132). Drilling an unconventional gas well may take 4-5 weeks continuous activity, and several months where multiple wells are drilled and fractured on a single pad. Noise impacts are likely to be of most concern where well development is close to human settlement. Few noise impacts are associated with production wells other than vehicle traffic for monitoring or maintenance purposes.

Other nuisance impacts may include light pollution, as well development generally continues 24 hours per day; increased vehicle traffic, often including on public rural roads; odours from various products used during drilling and fracturing; and reduced visual amenity (CCA, 2014, pp142-145).

The Santos submission (p55) notes that noise emissions from well sites during hydraulic stimulation are localised and short term; and that well sites are typically remotely located and not likely to have a significant impact.

Consultation with landowners about proposed operations may initiate procedures to mitigate any noise impacts. Work health and safety procedures include managing the noise exposure of personnel on site.

In the NT, noise is one of the environmental impacts and risks that is required to be addressed in the operator’s Environment Plan required for project approval (DME submission, Attachment D, pp105).

Findings

The Inquiry finds with respect to Noise, that:

- noise is one of a number “nuisance” impacts associated with unconventional gas extraction, although noise impacts occur primarily for a limited time during drilling and fracturing, and may not be a significant issue in most remote locations;
- for a variety of reasons including protection of human health, the Government could consider setting minimum “setback” distances between gas wells and specified features including living area boundaries. Alternatively this could be managed through risk assessment during environmental impact assessment processes.

5.8 Monitoring Requirements (ToR 5.8)

Robust monitoring regimes are an important part of effective management and regulation of any resource activity, including unconventional gas production. Monitoring, which provides data to assess the impact, at various scales, of resource activities; should be a key part of an adaptive management regime that allows continual improvement in operator practice; informs auditing compliance with regulation; can allay public concern about negative impacts and help maintain a social licence to operate for the industry; and may help to fill knowledge gaps in relation to aspects of Australian shale gas basins and baseline environmental conditions.

General principles of monitoring and their application to industry development and regulation have been discussed in a number of recent reviews of unconventional gas extraction (ACOLA, 2013, Chapter 12; CCA, 2014, Chapter 8). ACOLA (2013, p171) noted the importance of monitoring having a well-defined purpose, rather than be seen merely as a regulatory “box-ticking” exercise. The cost of monitoring is also often overlooked, or ignored, with ACOLA (2013, p171) estimating that this may be in the range of 1-3% of the total capital and operational lifetime cost of a gas field. CCA (2014, p148) also cautioned that the scientific basis for assessing the environmental impacts of shale gas development is weak, largely due to insufficient scientific monitoring; and that there is a need for research to be done to determine how monitoring should best be done with respect to several of the potential impacts.

Specific monitoring requirements and practices have also been described in relation to particular aspects of hydraulic fracturing and unconventional gas production in

other Sections of this Chapter. While most aspects have specific monitoring requirements, including for compliance purposes under current NT regulatory regimes, five areas for particular attention can be highlighted. These areas have also been identified by other reviews and raised in submissions to this Inquiry:

- ground water and surface water monitoring, that can detect contamination due to unconventional gas operations (Sections 5.2, 5.4, 5.5). This must include adequate baseline surveys to distinguish contaminants from natural or pre-existing sources;
- accurate monitoring of methane levels from fugitive emissions (Section 5.6);
- long-term monitoring arrangements for abandoned wells (Section 5.9);
- environmental indicators for cumulative impacts on biodiversity and ecosystem services from the development of potentially large numbers of wells across a gas field (Section 5.1); and
- monitoring of well integrity and fracture performance during hydraulic fracturing operations, including microseismic monitoring to validate fracture modelling in poorly known formations (Section 5.2).

The DME submission (p24) noted that, as part of the Environmental Plan for onshore petroleum projects, the operator must address its responsibilities for monitoring in the Implementation Strategy. Several Clauses in the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) set out requirements for monitoring well integrity and safety during drilling (510, 511) and production (601-635). The Environment Plan must also include details of water monitoring to be undertaken, including during and after fracture stimulation activities. The DME Submission (p 24) noted that the current regulatory framework does not recognise microseismic monitoring, which is to be addressed during development of new Regulations.

Findings

The Inquiry found with respect to Monitoring Requirements, that:

- robust monitoring regimes will be crucial to the effective management and regulation of a developing unconventional gas industry in the NT, and that monitoring requirements in addition to those for standard regulatory compliance should be carefully considered;
- NTG should establish a multi-agency working group that will collaborate with industry to establish standards and protocols for key monitoring programs associated with the development of an unconventional gas industry in the NT, particularly relating to ground water quality, hydraulic fracture performance,

fugitive emissions, well abandonment and environmental indicators for cumulative regional impacts; and

- monitoring data should be collated in standard formats in a central data repository and, with accompanying analyses and interpretation, be made publicly accessible.

5.9 Rehabilitation and Closure of Wells (Exploratory and Production) including issues associated with Corrosion and Long Term Post Closure and Site Rehabilitation for areas where Hydraulic Fracturing Activities have Occurred (ToR 7.10 and 7.11)

Gas wells are closed and decommissioned when they are no longer required -these may be exploration or appraisal wells that do not show sufficient flow to be brought into production, or production wells that have reached the end of their life span (usually between 15 and 30 years).

The term “abandoned” is also used in reference to closed wells, which evokes an impression that they are simply left open and unmanaged. There is strong public concern about such “abandoned” wells, and indeed many reported incidents of ground water contamination and fugitive methane emissions in North America can be at least partly attributed to leakage from closed wells, arising from past poor construction and/or decommissioning practices (see Section 5.2 and 5.6) - although most of these old wells are relatively shallow, conventional oil and gas wells.

Poor historical regulation of well abandonment in the USA has meant that the locations of many “orphan” wells are not known or accurately databased. For example, Pennsylvania may have as many as 180,000 orphaned wells, of which only 12,140 have known locations, and New York State has an estimated 40,000 abandoned wells that remain unplugged or whose locations are unknown (Arthur and Cole 2014). Due to the risks associated with drilling or fracture propagation intersecting previous wells, abandoned well interference assessment, including remote sensing for old well locations, has become a standard part of the early exploration phase for unconventional gas in parts of North America (King, 2012, pp53-55).

Current leading practice for well closure aims to plug the well in a way that permanently isolates the hydrocarbon zone from other geological layers, including

aquifers. Well plugging involves inserting a mechanical seal and a metal or polymer packer inside the casing, and 30 to 50m of cement inside the casing on top of the packer. Geological information for the wellbore is used to identify zones where plugs should be placed to isolate different strata, and determine the number of plugs required. Pressure and/or mechanical testing are used to verify plug integrity. The casing intervals between the cement plugs can also be filled with corrosion-inhibiting fluid so that cement and steel casing are not in contact with the air.

If the well is being fully decommissioned, all equipment is removed from the well, the well sump is drained, filled and compacted, and the casing and cement is cut off below the ground surface. The location of the well is marked on the surface as required by local regulation. If the well is being suspended, some surface equipment will remain on the wellhead. If problems with well integrity are detected after decommissioning, it is generally possible to “re-enter” the well and remediate the problem, either through “perf and squeeze”,⁹⁹ casing patching or additional cement plugs.

Once the well itself is closed, the well pad hardstand material can be removed and the site rehabilitated close to the original condition. An example of rehabilitation practice in Australia is described in the Santos submission (pp56-58), including a rehabilitation audit process and requirement for landholder satisfaction. As individual well pads are small, the rehabilitation process is relatively simple, and the most significant issue is likely to be ensuring there is no residual contamination from waste water treatment ponds.

The risks and incidence of well leakage, including from decommissioned wells, are described in Sections 5.2 and 5.6. It is not necessarily appropriate to extrapolate estimated leakage rates in older wells to predicted outcomes for wells constructed using modern casing and cementing materials and practices.¹⁰⁰

Cemented wells can maintain good integrity after 40 years, despite large variation in reservoir pressure (King, 2012, p21) and industry proponents maintain that if properly constructed and decommissioned “*the well essentially becomes part of the rock and will afford protection in perpetuity*” (Santos submission, p 25). There is, however, some evidence of surface casing vent flow from recent wells (citations in CCA, 2014, p58), and the CCA Report concluded that the degree of improvement claimed (in cementing and other practices to ensure well integrity) has not been

⁹⁹ perforating the casing at or above the leakage point (determined by cement bond logs, temperature logs or noise logs) and squeezing cement slurry into the region before patching the casing

¹⁰⁰ King and King (2013, pp 327-330) provide an useful discussion of incremental improvement in operational practice for oil and gas wells.

independently tested or verified. ACOLA (2013, pp128-129) stated that the longevity of integrity of decommissioned wells remains poorly understood and noted this as a topic where more information is essential, and where careful attention in terms of regulation and governance is required.

The RSRAE report (2012, p30) noted that if well abandonment in the UK is completed without unusual or adverse developments, no subsequent monitoring is currently required, and recommended that monitoring arrangements should be developed to detect possible well failure post abandonment. NSIRP (2014, pp212-213) also noted the development of slow gas leakage can take place years after well decommissioning and that this may be difficult to detect, particular if there is subsurface leakage into shallow strata. NSRIP (2014) also concluded that the longevity of well integrity is not known at present and requires investigation. That issue may be partly addressed in North America through the systematic re-examination of old wellbore sites; but in Australia the priority should be baseline studies to quantify, for example, ground water quality so that long-term occurrence and effects of well leakage can be more readily monitored.

The International Association of Hydrogeologists (NT) submission expresses concern that well integrity may be a particular issue in some NT ground water environments that are naturally corrosive. The submission cites the example of the McDill's deep oil exploration well that was drilled in the Perdika Basin in 1965 - the steel casing in that well was greatly corroded and major rehabilitation work was required about 45 years later to stem artesian flow. That well was not, however, constructed or decommissioned to current standards, and the casing was actually opened at depth and completed as a water bore (Humphreys and Kunde, 2008).

The possibility that wells may leak and require significant remedial action decades after they are decommissioned presents a significant challenge for government policy and regulation. Even with open-ended liability of operators for abandoned wells, it may be difficult to enforce remediation decades after a well is decommissioned (analogous with the burden that government has often adopted in the remediation of legacy minesites, in the NT and elsewhere).

This issue may potentially be addressed through some form of common liability or rehabilitation fund, one model for which is the WA Mining Rehabilitation Fund.¹⁰¹ In Canada, the Alberta Energy regulator collects an annual Orphan Fund Levy from all licencees, which is used to manage and remediate abandoned oil and gas wells

¹⁰¹ <http://dmp.wa.gov.au/19344.aspx>

and other facilities, for which there are no other legally responsible or financially able parties.¹⁰²

Monitoring and Regulation

In the NT, well suspension and abandonment must take place in accordance with Clauses 528 and 529 of the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012). Clause 529 is very prescriptive in terms of the location and length of cement and other plugs for a variety of well conditions (DME Submission, p67). Clause 532 and 626-628 of the *Schedule* provide the requirements for site restoration for exploration and production activities, including well plugging.

As part of the project approval process, the operator must include a Rehabilitation Strategy that forms part of the approved Environment Plan. This provides the basis for calculating a Rehabilitation Security that is paid to DME during project approval; when the project is completed the operator must demonstrate that rehabilitation has been carried out in accordance with the Strategy in order for the Security to be returned. The internal DME Guideline for environment rehabilitation reporting requires a final environmental audit to be carried out by a nominated third-party auditor after a period of at least one wet season from completion of last activities (DME submission, Attachment D, pp170-171).

The internal DME Guidelines for well suspension (DME submission, Attachment D pp166-168) require the installation and validation of a minimum of two permanent barriers with a documented Suspension.

However, no information is provided in the DME Submission about responsibility or requirements for long-term well integrity monitoring following abandonment.

By contrast, the *Code of Practice for Construction and Abandoning CSG Wells in Queensland* sets out principles, mandatory requirements and good industry practice for well abandonment.¹⁰³

In some Canadian jurisdictions, remedial action may be required before sealing the well, if mandated monitoring has detected any surface casing vent flow or evidence of loss of pressure integrity between the production and intermediate casings (NSIRP, 2014, p211). This typically involves perforating the casing at or above the leakage point (determined by cement bond logs, temperature logs or noise logs) and squeezing cement slurry into the region before patching the casing (“perf and

102 <http://www.eub.gov.ab.ca/rules-and-regulations/bulletins/bulletin-2013-01>; http://www.orphanwell.ca/pg_faq.html

103 <http://mines.industry.qld.gov.au/assets/petroleum-pdf/code-of-practice-csg-wells-and-bores.pdf>

squeeze”). Subsequent SCVF monitoring may be required to test remediation success before decommissioning proceeds.

Findings

The Inquiry found with respect to Well Closure and Site Rehabilitation, that:

- application of leading practice for construction and closure can minimise environmental risks associated with decommissioned wells, but the longevity of long-term integrity of decommissioned wells remains poorly understood;
- the NTG should work with industry and other Australian jurisdictions to ensure a consistent understanding of “leading industry practice” in relation to gas well closure and rehabilitation; and leading practice should be regularly reviewed with new or improved standards promptly adopted and mandated as appropriate;
- the NTG should collaborate with industry, other jurisdiction and research agencies to investigate the longevity of integrity in decommissioned wells, and technologies and practices that will minimise long-term risks from old wells;
- the NTG should work with industry to develop a framework for long-term monitoring of wells post abandonment, with clearly defined responsibilities and associated regulation;
- the NTG should consider the establishment of some form of common liability fund to ensure that resources are available for remediation of “orphan” wells; and
- the NT Government should ensure that adequate systems are in place for the long-term maintenance of comprehensive data for the location, condition and geological profile for all exploration and production gas wells; and that such data is readily available to all relevant stakeholders.

5.10 Induced Seismicity

Although not specifically referred to in the Terms of Reference, the possibility that hydraulic fracturing and aspects associated with gas extraction such as reinjecting waste water into strata may induce seismic events was raised with the Inquiry.

Induced seismicity has been addressed in some studies (e.g. US NAS, 2012; Leith, 2012) and other hydraulic fracturing inquiries (eg RSRAE, 2012; ACOLA, 2013) which have concluded that the risks are small:

“... the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events” (Leith 2012).

Microseismic events arise from propagation of fractures in the gas-bearing rock - the very purpose of hydraulic fracturing - so monitoring of microseismic events provides an important mechanism for mapping and modelling fracture propagation (Section 5.2.2). The nature of the shale or similar rocks targeted for fracturing limits the magnitude of seismicity (shale is relatively weak, allowing less energy to build up before breaking), as does the depth at which fracturing occurs. The pressure effects leading to seismicity are also constrained by the limited volume of rock affected, the limited timescale, and dissipation of pressure as fractures are created (Zoback, 2012). Consequently, the consensus is that seismicity induced by fracturing is unlikely to be at a magnitude greater than $3M_L$ (Green *et al* 2012), which is felt by few people and results in negligible, if any, surface impacts.

Larger seismic events induced by hydraulic fracturing can, however, occur when pressure effects intersect an existing pre-stressed fault, causing it to “slip” and release stored energy. A good understanding of fault structures in the vicinity of the fracturing operation is therefore desirable and best practice would include mapping local fault structures with 3D seismic and avoidance of fracturing adjacent to active faults. Accordingly, the approach to minimising risks of induced seismicity suggested by FROGTECH (2013, pp 21-22) is worth consideration.

Although induced seismicity may not be of sufficient magnitude to be felt (or damaging) at the surface, there is a risk of damage to well integrity, if the well casing is deformed at depth (RSRAE, 2012). This risk can be mitigated by appropriate monitoring of well integrity following fracturing (Section 5.2).

ACOLA (2013, p137) noted that the national seismic network operated by Geoscience Australia does not provide a record for most areas of small seismic events of the low magnitude associated with hydraulic fracturing, and it is therefore unreasonable to expect operators to provide a long-term seismic baseline prior to fracturing. ACOLA (2013) also noted that while establishing a small seismic array has modest hardware costs, the real expense lies in processing and interpreting the data.

As for other aspects of shale gas extraction, there would be considerable benefit in ensuring seismic and microseismic monitoring data gathered during preparatory and fracturing operations was made available through a data repository, to improve the knowledge base for fault structure and microseismic activity in Australian basins.

Induced seismicity associated with disposal of waste water through injection at depth may be more of a concern than seismicity associated with fracturing itself. There is some evidence from the USA of an increasing incidence of earthquakes of

magnitude $3M_L$ to $4M_L$ correlated with the deep disposal of large volumes of waste water, which create greater pressures over time than those caused by fracturing itself (Leith, 2012; US NAS, 2012). Seismic activity has also been caused by deep injection of large volumes of water for geothermal systems (Bachmann *et al*, 2011).

Davies (2013) reported that there have been only three recorded incidents of seismicity induced by hydraulic fracturing that were of sufficient magnitude to be felt at the surface, the largest of which (Horn River, Canada) had a magnitude of $3.8M_L$. There are no reports in Australia of induced seismicity associated with fracturing, either from CSG or shale gas activities (FROGTECH 2013).

Fracturing-induced seismicity in 2011 at the Cuadrilla Preese Hall shale gas well in the UK has been described and analysed in detail. Seismic events of $2.3 M_L$ and $1.5 M_L$ occurred following the second and fourth fracturing stage of the well, when relatively large volumes of fluid were injected. Subsequent investigations (de Pater and Baisch, 2011; Green *et al*, 2012) attributed the seismic events to transmission of injected fluid into a previously unidentified pre-stressed fault.

Leith (2012) stated that earthquakes of a magnitude equal to or greater than $3M_L$ in the USA midcontinent have risen from 21 per year for the period 1970 to 2000; to 31 per year for 2000 to 2008; and 151 per year since 2008 - although this is believed to be related to deep disposal of waste water rather than fracturing.

Regulation and Monitoring

Protocols and checklists have been developed to determine if fracturing and fluid injection cause seismicity and to mitigate seismicity induced by injection (NRC, 2012; US NAS, 2012). Other reviews have suggested that a formal seismic risk assessment should be included as part of the Environmental Plan preceding project approval (e.g. RSRAE, 2012, p46). FROGTECH (2013) outlined a broader approach, which included improving the scientific knowledge base on seismicity and structural geology and developing an Australian seismicity model.

One key element is the ability to modify operations in real time in response to seismicity monitoring. This would include a “traffic light” monitoring system with defined thresholds at which injection is reduced or ceased. The following thresholds were suggested by the company-commissioned report following the Preese Hall incident:

Magnitude $< 0 M_L$

Regular operations (green)

Magnitude between 0 and 1.7 M_L	Continue monitoring after injection for at least two days until seismicity rate falls below one event per day (amber)
Magnitude > 1.7 M_L	Stop injection and allow flowback, continue monitoring (red)

A Government-commissioned report (Green *et al*, 2012) recommended more precautionary thresholds (>0.5 M_L to cease operation). Such a system was applied to the stimulation of the Paralana geothermal project in South Australia (Petratherm, 2010, 2011).

The potential risk of damage to well integrity following seismic events can be mitigated by requiring repeat pressure tests and cement bond logs to be undertaken, with the results reviewed by appropriate experts and regulatory authorities (RSRAE, 2012). Some reviews highlight the importance of public outreach and communication as part of seismicity risk assessment and management, in order to build community consent to operate and allay concerns about seismicity risk.

In the NT, neither the *Schedule of Onshore Petroleum Exploration and Production Requirements* (2012) or the DME Guidelines for Environmental Plan Requirements specifically refer to induced seismicity or require a seismicity risk assessment or seismicity monitoring.

Findings

The Inquiry finds that with respect to the potential for Induced Seismicity, that:

- there is a low risk of seismicity of an intensity that will be felt or cause damage at the ground surface, but risks from induced seismicity can be minimised through leading practice planning, management and monitoring during fracturing operations;
- a seismicity risk assessment should be required as part of the Environmental Plan process for approval of fracturing or waste water injection operations;
- the NTG, in collaboration with industry, should establish “traffic light monitoring” thresholds to enable real-time response to any seismicity events occurring during hydraulic fracturing operations; and
- the NTG should ensure that information relating to fault structures, geological stresses and seismicity gained during exploration and operations is made publicly available by operators to improve scientific understanding and the knowledge base for Australian basins. This may best be done through referral to the COAG Energy Council with the proposition that Geoscience Australia host a national data repository.

Chapter Six - Other Aspects

While undertaking investigations and consultations, the Inquiry identified themes and aspects which, while not required to be covered in the terms of reference, are inextricably linked to the industry and its potential for future growth in the NT.

These aspects are:

- the concept of a social license to operate;
- cross-industry interaction: considerations for how the onshore gas industry can interact effectively, safely and cooperatively with other NT industries;
- local amenity: how the onshore gas industry can be managed to ensure the community's local amenity and enjoyment is protected; and
- environmental assessment process: how this can be strengthened to build confidence.

Placing emphasis on these aspects will provide additional layers of consideration for the proposed regulatory review and ensure a well-balanced approach to supporting industry development while helping build Territorian's confidence in the regulatory framework.

6.1 Social Licence to Operate

“This is the major issue with hydraulic fracturing - there is very little community trust in the process, the regulatory framework and the ability of companies to “engineer” every potential problem or risk. Without community trust, there will be no social licence to operate and hence grounds for community resistance to shale gas operations” (Arid Lands Environment Centre submission, p6).

“Confidence will require robust regulations, responsible operator practices and early and effective communication with stakeholders” (APPEA submission, p5).

Gaining community support, commonly referred to as “social licence to operate” was raised by many parties. There was, however, inconsistency about its meaning, value, who it involves and motivating factors.

Having regard to the aphorism that corporate behaviour should not be detrimental to health, the environment or enjoyment of property (Gunningham *et al*, 2002, p314), companies tend to place emphasis on community relations and reputation, while

other stakeholders are driven by different values and roles such as social justice, ecological sustainability or economic equality (Solomon *et al*, 2008, p144).

6.1.1 What is Social Licence?

CSIRO describes social licence as achieving “*ongoing acceptance or approval from the local community and other stakeholders who can affect [an operation’s] profitability.*”¹⁰⁴

The Australian Centre for Corporate Social Responsibility identifies four levels of social licence: withdrawal, acceptance, approval and psychological identification.¹⁰⁵ They also explain that the level of social licence can vary between stakeholders and can also change across the life of a project.

The following aspects help define social licence: it is tacit, intangible and context specific; it needs to be earned; it requires trust (particularly to move between the levels of acceptance); and it is dynamic as experiences, activities and perceptions of an operation shift overtime (Walton and Williams, 2013, pp1 and 3).

There is a view that the “social licence” concept emerged from community opposition as a mechanism to ensure industry viability. Others have argued that it emerged from risk-management frameworks which considered community stakeholders a risk to be managed. Owen and Kemp (2013, pp29 and 3) believe that social licence actually limits discussion, information sharing and debate on important topics and that the term could be used by industry to disguise or silence opposition.

Following their research which focused on the mining industry, Owen and Kemp (2013) concluded that “contemporary application of social licence is more about reducing overt opposition to industry than it is about engagement for long-term development” (p34).¹⁰⁶

In order for a “fair dinkum” social licence to be gained in the NT for the shale gas industry, a longer term focus should be adopted which will require open engagement and information sharing. This could also help to address the very high level of community cynicism towards government and its agencies that emerged during consultations.

¹⁰⁴ <http://www.csiro.au/Organisation-Structure/Flagships/Minerals-Down-Under-Flagship/mineral-futures/Project-Social-licence.aspx>

¹⁰⁵ <http://www.accsr.com.au/html/sociallicense.html>

6.1.2 Why is it Important?

Achieving and maintaining a social licence is important because it signals a shared level of understanding and acceptance between all of the parties involved. Most importantly, it indicates reconciliation of aspects where corporate motivations differ from the community's - and in many instances this is a significant challenge, particularly when you consider that communities and stakeholders are not homogenous (Owen and Kemp, 2013, p34; Walton and Williams, 2013, p13).

The Inquiry supports the notion that social licence is multi-layered, requiring different levels and types of engagement and information for different parties. This sentiment is shared by some people who presented to the Inquiry. Walton and Williams (2013) concluded that just as communities are not "homogenous in their experiences, expectations and perceptions of an industry operating in their midst" (p13), a social licence itself is not homogenous.

Research also highlighted that in some instances the conditions demanded by the community and stakeholders may in fact be tougher than those imposed by regulation and include measures that are not part of the regulatory requirements, resulting in "beyond compliance" by companies (Gunningham *et al*, 2004, p308).

The Northern Land Council supports the key recommendations of the ACOLA Report: "Communication, transparency and meeting community expectation will help to build community consent to operate" (Northern Land Council submission, p9).

6.1.3 Who is Responsible for Gaining and Maintaining the Social Licence?

Gaining social licence is closely linked to reputation, risk management and risk mitigation and some organisations are equally, if not more motivated, by maintaining a positive community relationship than by regulations (Gunningham *et al*, 2004, p321; Solomon *et al*, 2008, p 144).

While a social licence needs to be earned by the operator/industry, it would be inappropriate to assign all responsibility for that to companies.

In addition to meeting regulatory requirements, companies acknowledged that gaining and maintaining social licence is vital in recognising the potential (albeit still unknown) of the shale gas industry in the NT. It should be noted, however, that environmental groups and some individuals were overtly cynical about the value

that industry actually places on community benefit and the environment as opposed to operating profits.

Regulators and policy makers need to recognise the influence of social licence on their roles and how social and legal licences interact with and influence each other. From the consultations, one point of strong agreement was that a strong legislative and regulatory framework with suitably resourced and skilled regulators is critical for the industry and in this way Government, by setting the minimum requirements of industry, and monitoring compliance, plays a pivotal role in enabling social licence to be achieved and maintained.

“It will be vital for industry and government to recognise the complexity of the challenges posed by these possible [environmental] impacts. However most of these can be minimised where an effective regulatory system and best monitoring practice are in place and can be remediated where they do occur” (NT Environmental Defenders Office submission, p1)

“Public reporting [on operator compliance with approvals] is essential for transparency to the market and interested parties, and can increase the accountability of industry and regulators” (NT EPA, 2014, p4).

At the Alice Springs community forum, Jimmy Cocking of the Arid Lands Environment Centre summed up the evenings proceedings by highlighting the fundamental importance of a robust regulatory regime and that this should be a pre-requisite before large scale exploration of unconventional hydrocarbons in the NT.

Community expectations can influence when and how regulators exercise their power/authority, and also lead to changes in regulations, legislation and associated requirements such as monitoring and reporting (Gunningham *et al*, 2004, pp329-331). In fact, compliance can be supported by communities who are empowered to raise concerns and participate in processes (Gunningham *et al*, 2004, p309).

Environmental groups, along with other peak and social organisations, are strongly represented in the NT. They have a select community followership and can gain significant public exposure. These groups also have a role in securing social licence. The important advocacy role they play to ensure environmental considerations remain at the forefront is acknowledged, although, they must also act with credibility and responsibility.

This was highlighted by a recent Western Australian ruling requiring the Conservation Council of WA to apologise publicly for making claims, which were

ruled to be “deceptive and misleading”, against the gas industry in a full page advertisement.¹⁰⁷

The recognition of a balanced approach to the environment, economy and development, reflected in submissions and during interviews was encouraging.

6.1.4 What are the Key Aspects to be Considered in Gaining Social Licence?

“If the shale gas industry is to earn and retain the social licence to operate, it is a matter of some urgency to have such a transparent, adaptive and effective regulatory system in place and implemented, backed by best practice monitoring in addition to credible and high quality baseline surveys” (NT Environmental Defenders Office submission, p1).

Several areas arose where the expectations and motivations of the community, stakeholders, regulators and industry do not appear to align entirely, such as:

- “effective” legislation and regulation;
- appropriate level of disclosure of chemical use;
- consistent application of water licencing and use;
- access to information (for example monitoring water and air quality);
- acceptable level of self-regulation by operators;
- effectiveness of the regulators in terms of capability and capacity; and
- effective consultation with the community.

It would be incorrect to assert that industry members do not share a desire to protect the environment. Operators expressed a strong commitment to “doing the right thing” in protecting the environment, with one stating emphatically that there is no benefit to industry or the community if the environment is damaged.

While the issues mentioned above are directly aligned with the terms of reference, other aspects which will require attention from industry, government and various stakeholder groups are discussed in Chapter Two.

Moreover, some fundamental factors were identified that will require all involved parties to work through collectively, such as:

- significant disagreement about what is “credible” or “good” as oppose to “bad” science and information. This is a highly emotive issue. Productive discussion between the parties will depend on focusing on scientific, academic and/or

¹⁰⁷ ABC, 21 October 2014, <http://www.abc.net.au/news/2014-10-21/newspaper-pulls-irresponsible-anti-fracking-ad/5830168>

evidence-based information. This in itself can be difficult, and during the course of developing this Report, the Inquiry was constantly challenged with verifying the sources and context of information that was presented to it as “fact”.

Distorting or biasing the conversation with unverified information or papers that are not based on valid scientific or academic research is not productive.

Conversely, withholding information which could assist can also be unproductive, and the reluctance of regulating agencies and industry to occasionally not be as forthcoming as they should be with data and information is a worry;

- the issue of ensuring free, prior, informed consent from land owners was raised, particularly in the context of consultation with Indigenous communities. This is equally important for pastoralists. Interestingly, this issue was raised not only by organisations such as Environment Centre NT, Environmental Defenders Office NT, Northern Land Council and Central Land Council, but also by concerned residents who attended the open community meetings. Academic research indicates that the public participatory process requires more clarity about the role and actual influence of participants on final decisions (Solomon et al, 2008, p146). It will be important that this is clearly articulated to support the foundation of trust required for a social licence; and
- the important and challenging role of land councils in facilitating the necessary negotiations between traditional land owners and exploration companies, emphasises the high level of concern by various stakeholders in the effectiveness of the consultation process. These concerns focused on how well the process (including the make-up of the group) and information provided actually helped land owners understand the potential operations, the risks and mitigation strategies and the implications of their agreement or disagreement at that stage. This position was not tested with traditional owners themselves, but the concern appeared genuine among other parties and in line with challenges associated with cross-cultural negotiations and where parties have different first languages.

The Inquiry was impressed by the understanding of the Land Councils about this and the way they go about discharging their role.

6.1.5 Is a Social Licence Possible?

Gaining social licence will be a significant contributor to successful development of any industry and the value of community engagement is reflected in the Australian Government’s Energy Green Paper (2014) which highlights the importance of

industry genuinely engaging with communities that have or could have an interest in projects as early as possible (p11, 20, 43).

An industry or organisation's social licence is impacted by a range of external and internal factors, which influence social expectations and the company's ability to respond to them (Walton and Williams, 2013, p5). Indeed, how parties conduct their business also has a significant influence on whether a social licence is achieved and maintained.

Achieving a social licence will not require blanket agreement - resolving discontent and disagreement can lead to creative and innovative solutions. However, it will require honest discussion and increased levels of trust which will have to be earned by all parties involved.

“We conclude that having citizens and communities involved in the risk assessment and decision-making processes regarding unconventional gas and oil development would be an important first step co-generating the knowledge that may help to unlock and mitigate potential problems before they occur, while increasing trust amongst stakeholders” (NSIRP, 2014, p3).

6.2 Cross-Industry Interaction

There are differing perspectives on whether the onshore gas industry can operate in concert with some of the Territory's other significant industries, primarily the agriculture, aquiculture and pastoralist sectors. Potential risks to the tourism industry were also raised by speakers at public forums and in the AFANT submission. Support from other industries is important in gaining social licence and these industries are heavily reliant on a healthy environment.

The ACOLA Report (2013) acknowledged that compensation for landowners directly impacted by industry activity is a complex and controversial issue and considered there is a need to review the current system and to explore whether there is a way for impacted communities to receive more direct returns (p27).

As environmental aspects are explored in detail through other sections of the Report, this part will focus on other issues such as land ownership, access rights, consultation, compensation and the frameworks established to protect the rights of land holders/occupiers. In this respect, the agriculture and livestock industries came to the floor during consultations. It's no small irony that these industries have themselves experienced tension in other parts of Australia.

6.2.1 Land Owners, Holders and Occupiers

In addressing this issue, land ownership and lease arrangements also need to be borne in mind. As highlighted earlier in the report, vast amounts of land in the NT are currently under pastoral lease, declared Aboriginal lands or national parks with a small percentage reserved for major centres. In addition, more than 90% of the NT has exploration permits granted over it, which provides the holder of the permit (or proponent) with various rights of access and responsibilities.

While land holders have a right to the “surface land” in Australia, petroleum resources below the earth’s surface are the property of the Crown in the State/Territory concerned. It should be noted that this is a different legal basis to that of other countries such as the USA, where the landowner legally owns the resources below the earth’s surface. In the USA, the negotiations between a land owner and operator include a focus on sale of the resource, whereas in Australia this debate is fundamentally around land access, preservation of the land for future use and suitable arrangements for co-existence.

The Courier Mail recently published an article which discussed the results of a survey conducted for Santos by Nielsen in the Roma, Rolleston and Tamaroom districts which have histories of seismic surveys, exploration and gas production.¹⁰⁸ The results showed that most farmers would be happy to have energy production on their properties with one grazier saying “you are better off embracing it and working with them”. Farmers also recognised the contribution the industry was making to the regional economy. Examples of the compensation landholders receive, including a disturbance fee and annual payment for wells, were outlined.

The President of the Lock the Gate movement was quoted within the same article saying, “*A landholder should have the right to say no. However the mining industry has all the power stacked in its favour*”. He suggested that about one third of farmers are happy to have activity on their land, one third were “concerned but reluctantly agreed” and one third “don’t want it at any cost”. He also suggested that if the survey was conducted in another region, such as the Darling Downs, the results would be different.

The right, or lack thereof, for a landholder to decline access for exploration and production purposes has been a key point of debate. The Inquiry notes that attempts in the Senate to pass Bills giving land owners the right to refuse such access have not been successful.

¹⁰⁸ <http://www.couriermail.com.au/news/queensland/santos-wins-farmers-and-graziers-to-csg-and-queensland-reaps-benefits/story-fnihsrf2-1226788114485?nk=1ca2b9c8efaa759f5e2d52c93c33c4eb>

6.2.2 Frameworks around Australia

Each jurisdiction has adopted different frameworks for managing the interaction between onshore gas and land holders within their legislation, so there is no single consistent approach, a matter that might be looked at under the auspices of the COAG Energy Council.

In NSW, proponents must have a written agreement with the land owner before they can enter the land and undertake exploration. The company must consult with the land owner on a range of matters including the number and location of drilling sites, specific areas they want to access and what type of activity will take place as part of securing the written access agreement.

In 2012, the NSW Government appointed the first Land and Water Commissioner to help address community concerns and provide farmers and landholders with a point of contact for guidance during any stage of the application, exploration or production process. The Commissioner empowers landholders in their negotiations with companies to ensure CSG activities are located and conducted in a manner which minimises the potential impact on farming activities, the environment and lifestyle of the landholder. The Commissioner also provides information about compliance and enforcement matters, land access agreements, remuneration, compensation and the rights and responsibilities of exploration companies.^{109 110}

At the time of submitting this Report, the NSW Government is working with peak agricultural stakeholder groups including farmers, irrigators, cotton growers and the petroleum industry to develop a voluntary Code of Practice for Land Access for landholders and petroleum explorers to use when negotiating land access agreements.

As part of its Strategic Land Use Framework, NSW has identified Critical Industry Clusters (CICs) covering highly productive industries within a region that are related to each other, contribute to the identity of that region and provide significant employment opportunities. New operations are not allowed within these areas. For example, at the start of 2014, the boundaries of the viticulture CIC in the Upper Hunter region were amended to add 19 wine-growing properties. This broader strategic framework is discussed further under local amenity.

In Queensland, the independent Gas Fields Commission is responsible for facilitating better relationships between landholders, regional communities and the

¹⁰⁹ <http://www.resourcesandenergy.nsw.gov.au/landholders-and-community/coal-seam-gas/the-facts/protections-and-controls>

¹¹⁰ <http://www.resourcesandenergy.nsw.gov.au/landholders-and-community/coal-seam-gas/the-facts/land-access>

onshore gas industry, as well as convening landholders, regional communities and the onshore gas industry for the purpose of resolving issues.¹¹¹ Resource companies are legally required to meet a number of conditions set out in the Land Access Code which sets best practice for communication between landholders and resource companies, and imposes mandatory conditions which companies undertaking activities on private land must comply with. Broadly, companies wanting to undertake exploration and extraction activities must reach an agreement with the land holder and on both the terms for their conduct while on the property and compensation.

It is recognised in South Australia that land access is a key factor for a long-term sustainable industry, and that both land owners and explorers have an obligation to care for the land and use resources sustainably.¹¹² Regulations establish clear obligations for the explorer when notifying and consulting with land owners, including providing sufficient information to enable informed decision making and understanding potential impacts of the operation.

Compensation is payable to the land owner for:

- deprivation or impairment of the use or enjoyment of land;
- damage to the land (not including that which will be remedied);
- damage or disturbance to any business or activities lawfully conducted on the land; and
- consequential loss.

In the NT, sections 81 and 82 of the Petroleum Act address the entitlements to compensation for landholders and occupiers with a registered interest. Part 81 addresses compensation to owners and establishes that the proponent is required to compensate the land owner/occupier for deprivation of use and enjoyment of the land, and any damage caused. If agreement on the amount of compensation cannot be reached, either party may refer the matter to the Tribunal. This function will be transitioned to the newly created NT Civil and Administrative Tribunal.

6.2.3 Industry Practices

APPEA has established a code of practice which stipulates that "Landholders or occupiers of the land where hydraulic fracturing operations take place will be entitled to fair and reasonable compensation which will be arrived at by

¹¹¹ <http://www.gasfieldscommissionqld.org.au/gasfields/about-us/powers-and-functions.html>

¹¹² <https://sarigbasis.pir.sa.gov.au/WebtopEw/ws/samref/sarig1/image/DDD/PGRG005.pdf>

negotiation".¹¹³ This was originally created in Western Australia but has since been adopted by APPEA as a national code of practice.

Steps have also been taken to assist with the relationship between land owners/holders and operators. For example, the NT Cattlemen's Association and APPEA have been developing a model pastoral land access and compensation agreement for petroleum activity. It is understood that this document is close to finalisation and some companies and pastoralists have started using it as a guide reaching agreements.

Additionally some organisations adopt internal policies to manage and enhance their negotiations with land owners within their operating procedures. For example, to ensure all their obligations are met and to maintain a strong relationship with landowners, Origin Energy has developed the Origin Disturbance Approval Process to manage access to and disturbance of land. A Landholder Relations Adviser is allocated to individual landowners to provide them with one point of contact and enable long term, productive relationships. Conduct and compensation agreements (CCAs) are also negotiated with landowners to define how both parties will work together.

Santos is also committed to ensuring landholders involved in all stages of their activities are comfortable with how they operate on their land considering lifestyle and business interests. Santos' website reports that they have voluntary land access agreements with over 300 landholders in Queensland. Arrangements in NSW include a compensation framework where landholders receive a land value based payment and may also assist with general upkeep and monitoring. This is underpinned by land access and services agreements.¹¹⁴

6.2.4 Can Onshore Gas Co-exist with Agricultural and Pastoral Industries?

While the mining and petroleum industries are significant contributors to the NT's economy and employment, agriculture, pastoralism and tourism are also important.

It is imperative, that the NT's industry diversity is preserved. In recognising that shale gas resources, like all other mineral and petroleum resources, are finite and production will only occur for a relatively limited time, it is important that it does not impact negatively on the sustainability of other enduring industries. In discussing the CSG industry's proposition to co-exist with agriculture, Walton and

¹¹³ http://www.newstandard.com.au/wp-content/uploads/2011/11/APPEA_Code_of_Practice.pdf

¹¹⁴ <http://www.santos.com/our-activities/eastern-australia/new-south-wales/community/working-with-landholders.aspx>

Williams (2013) highlighted the farming sector will need to believe that CSG operations are perpetuating their future or “at least not damaging it” (p.13).

A similar proposition is appropriate for the NT with respect to shale oil and gas.

The concerns raised by pastoralists and growers included:

- the mining/petroleum sector’s ability to access land for the purpose of exploration and extraction under the current legislative arrangements;
- risks associated with water (and the impacts for human/animal/plant health), land access issues, negative impact of mining companies on property roads, gates etc; and
- disparity in requirements between the mining/petroleum sector and farmers with regards to water licensing, usage and associated reporting and disclosure requirements.

Examples were provided from around Australia where farmers were dissatisfied with the attendance and conduct of proponents on their property and the associated media stories reflecting such sentiments. Conversely, some people indicated that co-existence is possible and provided examples where industry had worked well with pastoralists, with benefits flowing to the landholder in the form of infrastructure and other benefits.

For example, land owners in Queensland’s Miles district have benefitted from provision by Origin Energy of water generated by CSG exploitation piped to their properties. This aspect, the associated conduct and compensation agreements and direct observation that no adverse consequences have arisen from hosting well pads experienced by those property owners is said to have led to some farmers previously opposed to CSG exploitation changing their minds. Land holders showed the Inquiry firsthand how they had worked in tandem with the industry about the location of well pads and associated infrastructure to minimise the impacts on their farming and other activities.

The Inquiry therefore considers that provisions should be put in place to ensure NT farmers and pastoralists have a “right to negotiate” with proponents wanting to operate on their land. The Inquiry understands that recommendations have been made to the Australian Government from the Northern Development Task force along similar lines and that these are being considered in the context of developing the White Paper on Developing Northern Australian which is expected in the first quarter of 2015.

In addition to providing a secondary income to landholders, this provision could also ensure that they have some control over how and where activities takes place on their land, ensuring prime grazing and growing areas are protected, making best use of their knowledge about the land, impact of seasonal weather on ground water flow, and how that feeds into water sources for livestock and irrigation. Such provisions would also support information sharing and trust, and could also include ongoing sharing of the results of baseline tests and monitoring.

The Inquiry also notes recent media comments¹¹⁵ from the Executive Director of the NT Cattlemen’s Association that current rules around land access agreements are “totally inadequate from the landholder’s perspective.” While “not asking for the right to veto” access, they are asking for “a level of respect afforded to landholders and a method to have their queries and concerns addressed”. While acknowledging that some companies work very well with NT pastoralists, Ms Hayes proposed a number of elements such as a mandated requirement for negotiation between companies and land holders which addresses key items as part of the exploration permit process, as well as mandated gathering and sharing of environmental data. The NT Cattlemen’s Association did not make a submission to the Inquiry nor did they take up an invitation to meet with it.

The NT Government, as part of the recommended regulatory review, should also consider installing a Commissioner or similar office to provide advocacy and support to land holders during negotiations with explorers. The NSW and Qld models provide a good framework for such an arrangement.

6.2.5 Other Opportunities for Economic Development

The development of an unconventional gas industry in the NT may bring economic opportunities for associated industries and manufacturers. Two unusual examples arising from the hydraulic fracturing process came to light during the Inquiry: the requirements for large quantities of proppant and guar (described in Section 5.4). While proppant may be made from a range of materials, sintered bauxite ceramic proppant is favoured for deep and hot wells where a high strength material is required. Guar powder is very widely used as the gelling agent in hydraulic fracturing fluid, and is derived from the guar bean plant. This plant product was historically sourced from India and Pakistan, but is increasingly grown in Texas and Oklahoma as demand has increased. In Australia, both of these products are currently sourced from overseas, but the NT may be well placed to develop a local

¹¹⁵ <http://www.farmweekly.com.au/news/agriculture/cattle/beef/graziers-vulnerable-to-csg-risks/2717317.aspx?storypage=0>

industry for one or both of them, especially as fracturing operations become more frequent.

6.3 Local Amenity for the Surrounding Community

The NT is in a unique position to put clear measures in place to ensure local amenity is maintained and that future planning is well considered. This needs to take place within the context of the Territory landscape. Images from the USA of wells in back yards are not likely to be replicated in the NT when you consider factors such as the land area, population distribution and current reserves of land. That said, there is still a need to ensure the amenity of all communities and occupied areas, including those in remote areas, are considered. It is timely for such issues to be considered.

6.3.1 Establishing “Buffer Zones” and Reserve Blocks

During consultations, citizens highlighted their concerns at the proximity of operations to residential and other areas that they consider important to the identity of their local community, most notably popular nature reserves and water holes. Most often, the option of establishing “buffer zones” was raised. The Inquiry notes that there are many terms that are often interchanged when discussing this concept: buffer zones, exclusion zones, set-backs and reserve blocks.

There are generally two types of “zones” which are used to avoid or diminish risks associated with accidents, failures and other impacts;

- an exclusion zone, in which no activity may take place; and
- a buffer zone, where activity may be allowed, conditional on additional requirements and mitigation methods. (Professor O’Kane, 2004, p6)

The American Petroleum Institute recommends that wherever possible, exploration and production activities should occur away from areas identified as sensitive or high-exposure. These include (but are not limited to) residential areas, churches, schools, recreational areas and protected/endangered plants and animals. There are numerous examples of USA jurisdictions establishing minimum distances between community or residential facilities and new wells.

For example, in North Dakota a drilling permit will not be issued for an oil or gas well located within 150m of an occupied dwelling, unless waived by the owner. Permits issued within 300m of an occupied dwelling may have additional conditions imposed by the Commission. Similarly, Illinois has declared “setback provisions” so that wells cannot be within minimum distances from residences, places of

worships, schools, hospitals, nursing homes, wells and springs used for human and domestic animal consumption, perennial streams, high water marks or rivers, lakes and reservoirs, nature preserves and surface water or ground water intake of a public water supply.

As well as addressing general concerns about the proximity of such activities to residential and other community-focused areas, buffer zones also help with mitigating concerns and risks related to noise, light, increased traffic, atmospheric pollution and general safety (NSIRP, 2014, p132).

In the NT, reserve blocks are in place around Darwin and other regional centres that prohibit petroleum activities from taking place within them as per Section 9 of the *Petroleum Act*. Refer to Figure 6-1 (provided by DME) on the following page. The Inquiry understands that these are under review to ensure sensitive areas are also included. Also, petroleum activities cannot take place on Aboriginal free hold land that has been placed into moratorium by Traditional Owners.

Taking into account NT population growth and the associated expansion in residential areas, these reserve blocks should be reviewed to ensure they allow for future municipal and township areas and also take into account other areas of significance. It is also recommended that public accessibility to information about reserve blocks, including detailed maps, be vastly improved.

In reviewing and setting such zones, controls should be adaptable as knowledge increases based on monitoring and experience. Conservative measures should be established which could be amended as knowledge and understanding of sites increase by monitoring actual against predicted impacts (Professor O’Kane, 2014, p15).

6.3.2 Strategic Land Use Planning

Strategic land use planning provides a foundation for managing local amenity and managing competing interests in land. An integrated approach to land use management attempts to negotiate the most appropriate course of action, bearing in mind the areas ecological and social limits (MMSD Project, 2002, p145).

In 2012, NSW introduced a Strategic Regional Land Use Policy¹¹⁶ to balance the needs of communities, farmlands and resource industries and help manage the potential conflicts associated with the proximity of such activities. Exclusion zones, which ban CSG activity within a 2km buffer, came into effect for residential areas in all 152 NSW Local Government Areas in October 2013. These were extended in

¹¹⁶ <http://www.nsw.gov.au/initiative/strategic-regional-land-use>

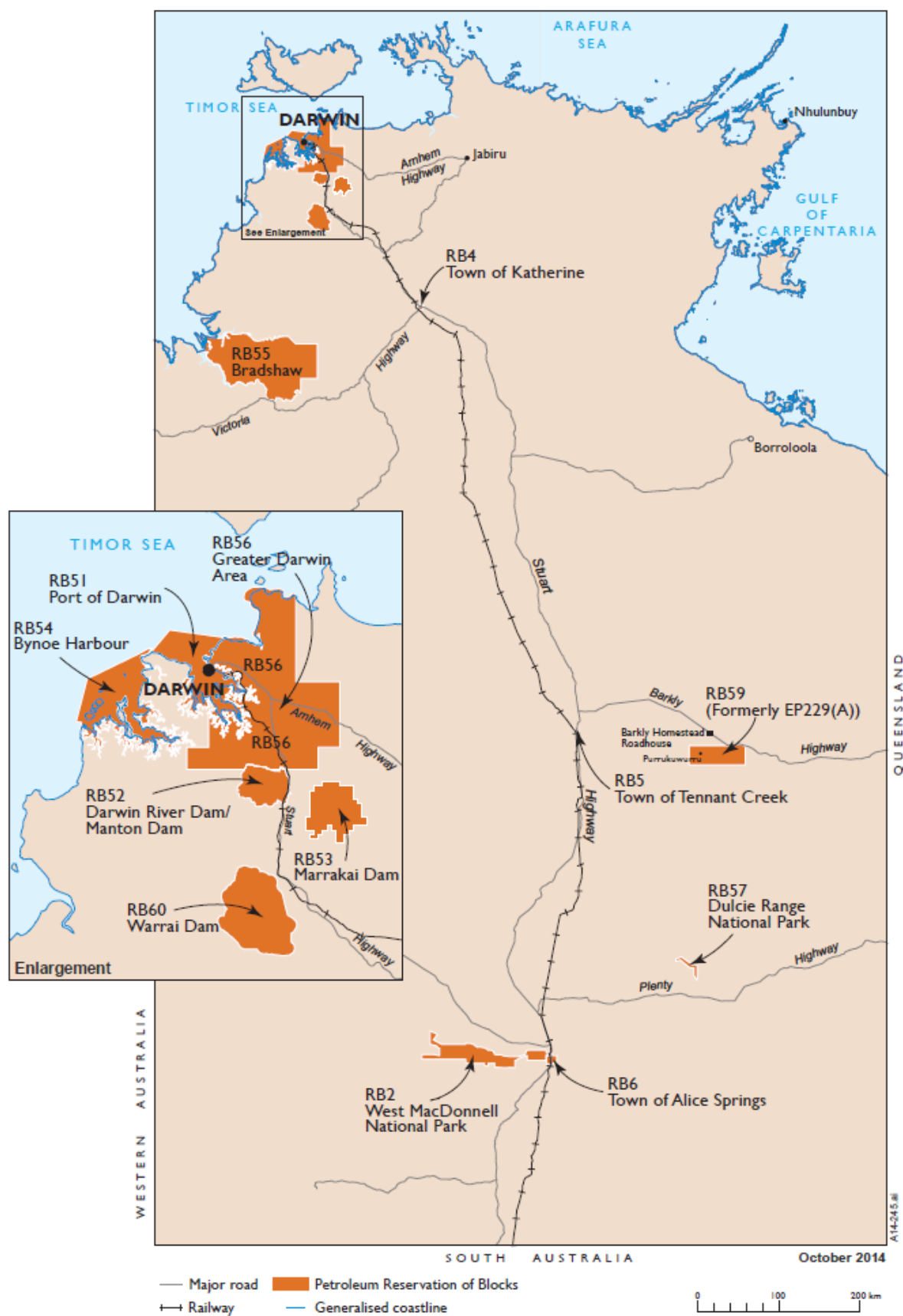
January 2014 for future residential growth areas and seven rural villages. This means that 95% of NSW dwellings within petroleum licence areas are comprehended by exclusion zones. Critical Industry Clusters, discussed earlier, have also been established. As well as taking into account how these industries support local employment, they also consider the identity of the area and the benefits brought to the local community.

In considering local amenity, measures should be established as soon as possible to give the public confidence that communities, and all they entail, will be protected into the future. These should be considered in concert with input from community leaders, taking into account future growth requirements and community aspirations.

The Inquiry notes that the NT Government has included long-term strategic land use plans across the Territory as an objective under its Draft Economic Development Strategy. These plans should cover the onshore gas industry and put appropriate measures in place to protect regional identity and community amenity. This planning should also consider enduring industries and protection of areas of significance. This body of work might also be addressed by the proposed Cabinet Sub Committee.

Figure 6-1: Reserve blocks in the NT

Petroleum Reservation of Blocks



6.4 Environmental Assessments

Many activities require environmental assessments before operations can begin.

This process identifies potential risks, assesses their likelihood and considers the mitigation measures that can be taken to either remove or reduce the likelihood and impact of each risk. Importantly, the assessments are site and operation specific and take into account all elements of the environment.

In Australia, State and Territory Governments are responsible for regulation of the onshore gas industry (Department of Industry, 2014, p11). The Federal Government administers the EPBC Act and has been involved in associated aspects of the application approval process.

In the NT, the NT EPA is responsible for the environmental assessment process, including for onshore gas operations, in accordance with the *Environmental Assessment Act* and its subordinate Environmental Assessment Administrative Procedures.

The scale and complexity of a proposed development, and the significance of potential impacts will determine what level of assessment is required, test the effectiveness of the proposed safeguards to mitigate these impacts and recommend actions to ensure the construction and operational phases of a project can be managed in an environmentally sound manner.

At the time of writing this Report, bilateral agreements were being negotiated between the Australian Government and each State/Territory with the objective of establishing a “One Stop Shop” to enable one assessment and approval process to satisfy both State/Territory and Federal requirements.

The Commonwealth/NT assessment bilateral has been agreed and is expected to come into effect in the near future.

Work is now proceeding on an approvals bilateral agreement between Commonwealth and Territory officials,

There is, however, a risk to the admirable aim of a “One Stop Shop” as changes to legislation and regulations will have to pass through the Senate in accordance with the disallowable instrument procedure.

The NT ecology is characterised in large part by broad representative areas such as the arid zones and the Barkly Tableland and downlands. It is therefore feasible to map bio-regions and gather baseline information to inform strategic environmental

assessments. This approach would set pre-determined conditions to be applied to assessing the potential impacts of disturbed areas.

Assessing these impacts in the context of the broader surrounding ecology under pre-determined conditions can result in considerably shortened approval timeframes and remove the need for an EIS for every single project.

While initial costs of assessment may be high, some work has already been done or is in train; soil mapping and aquifer identification being two such work programs currently underway. The cost of this work could be recovered through tenement rentals or application fees if deemed appropriate by the NT Government.

In any event, the new assessments and approvals bilaterals will require a restructuring of the *NT Environmental Assessment Act*.

This exercise would also take into account the related aspects raised in Chapter Five of this Report.

Recommendation

The Inquiry recommends that the *NT Environmental Assessment Act* be restructured in the light of this Report and the proposed bilateral agreements with the Commonwealth on environmental assessments and approvals.

Current NT Arrangements

In an effort to provide one interface for industry, the Environment Management Plan is submitted to DME as part of the project approval process. DME checks the plan against a checklist and then refers the information to the NT EPA for their assessment as well as other appropriate agencies such as Land Resource Management and Parks and Wildlife.

Information brought to the Inquiry's attention raised some concern about the extent and consistency of which practices are aligning with established processes and leading practice, and the effectiveness of interactions between the various parties involved. That the environment assessment process is detailed and represents a significant investment in both time and resources is acknowledged.

For example, during discussions with Imperial Oil and Gas it emerged that they have spent \$4m on the EIS process so far over the past four years without yet commencing exploratory drilling.

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Annex A: Media Release, Minister for the Environment



PETER CHANDLER MLA | Member for BRENNAN
MINISTER FOR LANDS, PLANNING AND THE ENVIRONMENT

MEDIA RELEASE

INQUIRY INTO FRACKING

20 February 2014

Minister for the Environment, Peter Chandler, made a recommendation today that the government initiate an inquiry into hydraulic fracturing in the Northern Territory and the potential effects on the environment.

"Hydraulic fracturing or fracking could be the key to unlocking huge economic benefits for the NT oil and gas industry," Mr Chandler said.

"However, people are unsure about what the potential impacts from these practices could have on the environment and that does create some angst.

"These community concerns have led me to recommend that this government commission an inquiry in to the potential environmental impacts of hydraulic fracturing in the Northern Territory.

"It is my intention that the inquiry will look at assessment of environmental risks, actual environmental impacts and the effectiveness of mitigation measures.

"I have written to the chair of the Northern Territory's independent EPA, Bill Freeland, informing him of my intentions to recommend the inquiry and seeking his advice on appropriate terms of reference and a recommendation of qualified persons to lead or assist in an inquiry of this nature.

"The inquiry aims to separate the actual environmental risks from the perceived risks and clear up some of the claims about hydraulic fracturing that have caused significant public concern.

"Recommendations of effective methods for mitigating actual environmental impacts will come from the inquiry.

"We are a government that is open for investment but those investments cannot come at the cost of our unique environment.

"I want this inquiry to provide Territorians with accurate information so they can have the upmost confidence in our regulatory framework."

Media Contact: Jarrad Schwark 0437 914 736 or 8928 6617

Annex B: Media Release, Chief Minister



ADAM GILES MLA | Member for BRAITLING

Chief Minister

MEDIA RELEASE

COMMISSIONER ANNOUNCED FOR FRACKING INQUIRY

19 March 2014

Doctor Allan Hawke AC has been appointed to head-up the Territory Government's inquiry into hydraulic fracturing.

"Dr Hawke is eminently qualified to lead the inquiry. He is a former Diplomat, former Chancellor of the Australian National University, senior public servant in Canberra and one time Chief of Staff to Labor Prime Minister Paul Keating," Chief Minister Adam Giles said.

"Since retiring, he has conducted a number of high level reviews for the Australian Government and other jurisdictions including *The Hawke Report* into the *Environment Protection and Biodiversity Conservation Act*."

Dr Hawke will formally start his work as Commissioner in early April and will call for public submissions on this important issue.

"The Territory has vast reserves of shale gas located more than a kilometre below the earth's surface which could be unlocked using hydraulic fracturing," Mr Giles said.

"The use of this technique could generate many millions of dollars in export earnings for the Territory and an opportunity to secure the country's energy supply but we understand this should not come at the cost of our environment.

"Shale gas fracking is fundamentally different to coal seam gas fracking which is used interstate because coal seam gas is usually located closer to the surface and nearer to ground water aquifers.

"We intend to give the public accurate information about the scale of environmental risk this presents.

"We know this issue is a contentious one but we want the public to have confidence in this process and so have ordered a thorough inquiry.

"The aim is to separate the proven evidence about environmental risk from the myths and to give an accurate picture based on science."

The Inquiry will result in recommendations on whether steps should be taken to mitigate any potential impacts from fracking.

Dr Hawke is expected to report back to the Government by the end of the year.

Media Contact: Danielle Parry 0413 081 801

Annex C: Terms of Reference for the Inquiry

Hydraulic fracturing for hydrocarbon deposits in the Territory, including the assessment of the environmental risks and actual environmental impacts of hydraulic fracturing and the effectiveness of mitigation measures, and more particularly the matters mentioned in the following clauses:

1. Historical and proposed use of hydraulic fracturing (exploration, appraisal and production) of hydrocarbon deposits in the Northern Territory (number of wells; locations; timeline).
2. Environmental outcomes of each hydraulic fracturing activity for hydrocarbon resources in the Northern Territory (number of wells; frequency of types of known environmental impacts).
3. Frequency of types and causes of environmental impacts from hydraulic fracturing for hydrocarbon deposits in the Northern Territory and for similar deposits in other parts of the world.
4. The potential for multiple well pads to reduce or enhance the risks of environmental impacts.
5. The relationship between environmental outcomes of hydraulic fracturing of shale petroleum deposits with geology, hydrogeology and hydrology.
6. The potential for regional and area variations of the risk of environmental impacts from hydraulic fracturing in the Northern Territory.
7. Effective methods for mitigating potential environment impacts before, during and after hydraulic fracturing with reference to:
 - the selection of sites for wells
 - well design, construction, standards, control and operational safety and well integrity ratings
 - water use
 - chemical use
 - disposal and treatment of waste water and drilling muds
 - fugitive emissions
 - noise
 - monitoring requirements
 - the use of single or multiple well pads
 - rehabilitation and closure of wells (exploratory and production) including issues associated with corrosion and long term post closure
 - site rehabilitation for areas where hydraulic fracturing activities have occurred.

Annex D: Call for Submissions



NORTHERN TERRITORY OF AUSTRALIA

CALL FOR PUBLIC SUBMISSIONS HYDRAULIC FRACTURING INQUIRY

Dr Allan Hawke AC was appointed by the Northern Territory Government to undertake an Inquiry into Hydraulic Fracturing in the Northern Territory under the provisions of the *NT Inquiries Act*.

The Inquiry commenced on 14 April 2014.

Dr Hawke is welcoming public submissions to help inform the development of a report to the Northern Territory Government before the end of 2014.

Please email the Hydraulic Fracturing Inquiry Secretariat at hydraulicfracturing.inquiry@nt.gov.au or post your submission to Hydraulic Fracturing Inquiry, c/-GPO Box 4396, Darwin NT 0801. The due date for submissions is 31 May 2014.

For more information on the review and to read the terms of reference please visit www.hydraulicfracturinginquiry.nt.gov.au

It is intended the submissions will be put up on the website in the interests of transparency.

Annex E: List of submissions

No.	Submission Received	Author
1	19 April 2014	Kate Christianson
2	23 April 2014	Angus Elliot
3	30 April 2014	Margaret McBean
4	01 May 2014	Bernie Fernadez
5	01 May 2014	Donna Schubert
6	03 May 2014	Ruth Cardier
7	03 May 2014	Name withheld
8	05 May 2014	Sharon Scurr
9	06 May 2014	Shaun Leyland
10	06 May 2014	Robert Dietrich and Boudicca Hann
11	11 May 2014	Daniel Fuller
12	12 May 2014	Name withheld
13	12 May 2014	Donna Tapp
14	12 May 2014	Julie Morris
15	12 May 2014	Vicki Gordon
16	12 May 2014	Name withheld on request
17	12 May 2014	Michael Machin
18	13 May 2014	David Anthony
19	14 May 2014	Name withheld
20	14 May 2014	Name withheld
21	14 May 2014	Name withheld
22	14 May 2014	Name withheld
23	14 May 2014	Name withheld
24	14 May 2014	Name withheld
25	14 May 2014	Name withheld
26	14 May 2014	Name withheld
27	14 May 2014	Name withheld
28	14 May 2014	Name withheld
29	14 May 2014	Name withheld
30	14 May 2014	Simone Cordell
31	14 May 2014	Sam Marynowicz
32	14 May 2014	Jack Henderson
33	14 May 2014	Fred Vant Sand
34	14 May 2014	Tal Haim
35	14 May 2014	Rebecca Adams
36	14 May 2014	Name withheld on request
37	14 May 2014	Name withheld on request
38	15 May 2014	Koel Wrigley
39	15 May 2014	Name withheld
40	16 May 2014	Name withheld
41	17 May 2014	Name withheld

42	17 May 2014	Name withheld
43	17 May 2014	Laurie Boehler
44	17 May 2014	Carol Phayer
45	19 May 2014	Geoff Hokin – Imperial Oil and Gas
46	20 May 2014	Amy Dargan
47	21 May 2014	Joyce Madden
48	21 May 2014	Name withheld
49	21 May 2014	Name withheld
50	21 May 2014	Shaun Metcalf
51	21 May 2014	Name withheld
52	22 May 2014	Name withheld on request
53	22 May 2014	Duncan Stitfold
54	23 May 2014	Tanya Hall
55	23 May 2014	Uncle T A Turner
56	24 May 2014	Phil Walcott
57	23 May 2014	Name withheld
58	25 May 2014	Name withheld on request
59	25 May 2014	Name withheld
60	25 May 2014	Bob Durnan
61	25 May 2014	Fiona Morrison
62	25 May 2014	Leon Hower
63	25 May 2014	Name withheld
64	26 May 2014	Name withheld on request
65	26 May 2014	Jessie Johnston
66	26 May 2014	Margaret Lavery
67	26 May 2014	Vin Bugno
68	26 May 2014	Peter Tibbits
69	26 May 2014	Ty Stryk
70	26 May 2014	Megan Hatton
71	26 May 2014	Name withheld on request
72	26 May 2014	Name withheld
73	26 May 2014	Name withheld on request
74	26 May 2014	Mary McConville
75	26 May 2014	Irene Gale
76	26 May 2014	Vanessa Rowell
77	26 May 2014	Name withheld on request
78	26 May 2014	Hilda Henderson
79	26 May 2014	Justin Rowe
80	26 May 2014	Cheryl Hughes
81	26 May 2014	Bindi Isis
82	26 May 2014	Beck Adams
83	26 May 2014	Will Chance
84	26 May 2014	Deborah Wildish
85	26 May 2014	Name withheld on request
86	26 May 2014	Daniel Peterson
87	26 May 2014	Dior Fletcher
88	26 May 2014	Name withheld on request

89	26 May 2014	Name withheld
90	26 May 2014	Teresae Cunningham
91	26 May 2014	Name withheld
92	26 May 2014	Lalitha Chelliah
93	26 May 2014	Name withheld
94	24 May 2014	Name withheld
95	26 May 2014	Name withheld
96	26 May 2014	Valerie Roberts
97	26 May 2014	Name withheld
98	27 May 2014	Name withheld
99	27 May 2014	Freya Tripp
100	27 May 2014	Frederic Meyering
101	27 May 2014	Name withheld on request
102	27 May 2014	Abbie Spiers
103	27 May 2014	Sandra Trull
104	27 May 2014	Laila Pedersen
105	27 May 2014	Andrew Laughton
106	27 May 2014	Carol Randall and Andrew Smith
107	27 May 2014	Jordan Braver
108	27 May 2014	Melinda Schroeder
109	27 May 2014	Lisa Chin
110	27 May 2014	Name withheld
111	28 May 2014	Name withheld
112	28 May 2014	Name withheld
113	28 May 2014	Tayla O'Keefe
114	28 May 2014	Name withheld
115	28 May 2014	Name withheld
116	28 May 2014	Name withheld
117	28 May 2014	Name withheld
118	28 May 2014	Christiana Pownall
119	28 May 2014	Marilyn O'Keefe
120	28 May 2014	Veet Karen Hedley
121	28 May 2014	Simon Ruckenstuhl
122	28 May 2014	Name withheld on request
123	28 May 2014	Name withheld on request
124	28 May 2014	Evelyn Cady
125	28 May 2014	Name withheld on request
126	28 May 2014	Ally Richmond – Don't Frack the Cox
127	28 May 2014	Chris Wilkinson
128	28 May 2014	Roger Miller
129	28 May 2014	Tavis Wilkinson and Louise Stokes
130	28 May 2014	Stephanie Buzza
131	29 May 2014	Anne Barrow
132	29 May 2014	Janet Stevenson
133	29 May 2014	Name withheld on request
134	29 May 2014	Roz Stevens
135	29 May 2014	Lyn Wilkinson

136	29 May 2014	Name withheld on request
137	29 May 2014	Australian Academy of Technological Sciences and Engineering (ATSE)
138	29 May 2014	Alison Mapleson
139	29 May 2014	Errol Lawson
140	29 May 2014	Tanya Martinich
141	29 May 2014	Phillip Warsop
142	29 May 2014	Mrs R Saltmarsh
143	30 May 2014	Advent Energy Limited
144	30 May 2014	Toni Coutts
145	30 May 2014	Dr Lynn Day
146	30 May 2014	Name withheld
147	30 May 2014	Name withheld
148	30 May 2014	Name withheld
149	30 May 2014	Name withheld
150	30 May 2014	Name withheld
151	30 May 2014	Darcy Shilton
152	30 May 2014	Name withheld
153	30 May 2014	Miranda O'Keefe
154	30 May 2014	Alison Worsnop and Mike Bowman
155	30 May 2014	Australian Water Association
156	30 May 2014	Alex Kelly
157	30 May 2014	Max Tate
158	30 May 2014	Debra Froud
159	30 May 2014	Krissi Besic
160	30 May 2014	Jacinta Bull
161	30 May 2014	Statoil Australia Theta B.V.
162	30 May 2014	Origin Energy
163	30 May 2014	Petrena and Alex Ariston
167	30 May 2014	Barbara Saville – Central Petroleum Ltd
168	30 May 2014	Bethany Uhe
169	30 May 2014	Breath Clinton
170	30 May 2014	Name withheld
171	30 May 2014	Charmaine Roth
172	30 May 2014	Gina Trengrove
173	30 May 2014	Mark Zanker
174	30 May 2014	Mandy Webb
175	30 May 2014	Kayne Jansen
176	30 May 2014	Department of Mines and Energy
177	31 May 2014	Name withheld on request
178	31 May 2014	Name withheld
179	31 May 2014	Liz Moore
180	31 May 2014	Name withheld
181	31 May 2014	Name withheld on request
182	31 May 2014	Name withheld on request

183	31 May 2014	Ann and Robert Taylor
184	31 May 2014	Carmel Flint – Lock the Gate Alliance
185	31 May 2014	Catherine Orme
186	31 May 2014	Clement Bresson and Ingrid Johanson
187	31 May 2014	Emma Chessell – NT Greens
188	31 May 2014	Emma Treves
189	31 May 2014	Joe Lima – Schlumberger Australia
190	31 May 2014	Ruth Apelt
191	31 May 2014	Jacinta Stace
192	10 June 2014	Kerri Sullivan
193	01 June 2014	Name withheld
194	01 June 2014	John Carroll – Falcon Oil and Gas
195	01 June 2014	Name withheld
196	01 June 2014	Kim Roberts
197	02 June 2014	James G Nichols
198	02 June 2014	Geoff Farnell – Tamboran Resources
199	02 June 2014	Maria Woodgate – NT Branch of the International Association of Hydrogeologists
200	03 June 2014	Eni Australia
201	03 June 2014	Name withheld
202	04 June 2014	Name withheld
203	04 June 2014	Name withheld
204	04 June 2014	Name withheld
205	04 June 2014	Name withheld
206	04 June 2014	Name withheld
207	04 June 2014	Name withheld
208	04 June 2014	Name withheld
209	04 June 2014	Name withheld
210	04 June 2014	Craig Ingram on behalf of Warren d With – Amateur Fishermen’s Association NT
211	04 June 2014	Holly Tapp
212	04 June 2014	David Shearman – Doctors for the Environment Australia
213	05 June 2014	Melanie Walker – Public Health Association of Australia
214	06 June 2014	Name withheld
215	13 June 2014	APPEA
216	15 June 2014	Patrick Crimmins
217	17 June 2014	Friends of the Earth Melbourne – Cam Walker and Ian Mack
218	17 June 2014	Power and Water Corporation
219	20 June 2014	Pangaea Resources Pty Limited
220	20 June 2014	Scott Atkinson

221	20 June 2014	Name withheld
222	22 June 2014	Saul Francis Dalton
223	22 June 2014	Name withheld
224	22 June 2014	Name withheld
225	22 June 2014	Name withheld
226	22 June 2014	Name withheld
227	22 June 2014	Name withheld
228	22 June 2014	Name withheld
229	22 June 2014	Name withheld
230	23 June 2014	Mike Clarke
231	23 June 2014	Marlene Murphy
232	24 June 2014	Name withheld
233	25 June 2014	Name withheld
234	25 June 2014	Olga Milenkaya
235	25 June 2014	Olga Milenkaya
236	26 June 2014	Dennis Mangan
237	26 June 2014	M.E.T.T.S
238	27 June 2014	Name withheld
239	30 June 2014	Northern Land Council
240	30 June 2014	Centrefarm/TopEndFarm
241	30 June 2014	Arid Lands Environment Centre
242	30 June 2014	Environment Centre NT
243	30 June 2014	Name withheld
244	30 June 2014	Central Land Council
245	01 July 2014	Department of Land Resource Management
246	01 July 2014	Caitlin Perry
247	04 July 2014	Environmental Defenders Office
248	07 July 2014	Beach Energy
249	13 June 2014	Name withheld
250	26 June 2014	Name withheld
251	29 May 2014	Halliburton
252	26 July 2014	Name withheld
253	30 July 2014	Name withheld
254	30 July 2014	Name withheld
255	04 August 2014	Name withheld
256	15 August 2014	Nichole Vandersteegen
257	15 August 2014	Justin Tutty
258	18 August 2014	Supplementary – Krissi Besic
259	21 August 2014	Name withheld on request
260	11 September 2014	Addendum – Northern Land Council
261	29 September 2014	Samantha Phelan
262	28 September 2014	Supplementary - Krissi Besic
263	31 October 2014	Supplementary - Environmental Defenders Office

Annex F: Findings of the Inquiry

Selection of Sites for Wells and Use of Single or Multiple Well Pads

The Inquiry finds with respect to the Selection of Sites for Wells and Use of Single or Multiple Well Pads, that:

- the environmental (including social and cultural) impact of individual well pads is likely to be small and readily mitigated and regulated, but the cumulative impact of extensive well development over a gas play may be significant. The use of multiple well-pads is likely to reduce the environmental footprint of unconventional gas development;
- the current Project and Environment Plan assessment and approval process should be refined, to provide a one-stop-shop for developers while efficiently and transparently satisfying all legislative and regulatory requirements. This may require better structured arrangements between the lead and co-regulatory NT Government agencies, with the South Australian process providing a useful model;
- the NTG should develop an effective framework for strategic assessment of cumulative impacts of shale gas development, which could be applied if large gas plays are developed in the NT with potentially thousands of wells; and
- the NTG should work with industry to encourage the use of multiple well pads in order to reduce the environmental footprint of future shale gas development; including ensuring that there are no perverse policy or regulatory incentives for singular rather than multiple well development.

Well Design, Construction, Standards, Control and Operational Safety and Well Integrity Ratings

The Inquiry finds with respect to Well Design, Construction, Standards, Control and Operational Safety and Well Integrity Ratings, that:

- ensuring well integrity is a key aspect of reducing the risk of environmental contamination from unconventional gas extraction. Application of leading practice in well construction combined with rigorous integrity testing and effective regulatory oversight should result in a very low probability of well failure, but a ground water monitoring regime that can detect contamination attributable to unconventional gas activities is also desirable;
- the NTG should consider developing a Code of Practice for Shale Gas Wells, similar to those of Queensland and NSW for CSG wells. This should serve to

formalise some internal DME regulatory practices that are not adequately covered in the current Schedule;

- the NTG should work with industry and other Australian jurisdictions to ensure a consistent understanding of “leading industry practice” in relation to gas well construction and operation; and leading practice should be regularly reviewed with new or improved standards being promptly adopted and mandated as appropriate;
- regulation of shale gas extraction should embed standards and guidelines within a goal-based approach that, among other aspects, clearly elucidates the objective of avoiding aquifer contamination;
- the NTG needs to ensure that assessment, regulatory and compliance functions within its agencies are adequately resourced, and that appropriate expertise is obtained and maintained to keep pace with the rapidly developing technology and to satisfy industry and community expectations for a good regulatory framework;
- a transparent framework for reporting, investigation and resolution of, amongst other aspects, ground water contamination incidents should be maintained, both to build public confidence and refine risk assessment and best practice; and
- the NTG should collaborate with the Australian Government, research institutions and industry to develop a strategic approach to building a baseline for ground water quality, including natural methane levels.

Fracture Propagation

The Inquiry finds with respect to Fracture Propagation, that:

- the risk of fracture propagation in deep gas shale formations allowing hydraulic fracturing fluid, methane or brine to contaminate overlying aquifers is very low, and may be minimised by requiring leading practice in fracture operations, including fracture modelling and real-time and post-fracture monitoring;
- the NTG should consider developing a Code of Practice for Hydraulic Fracturing Activities, similar to that of NSW for CSG wells. This should formalise some internal DME regulatory practices that are not adequately covered in the current Schedule; and
- the NTG should collaborate with Australian Government, research institutions and industry to support a scientific program to develop a better understanding of stratigraphy, faults, stress distribution and deep hydrogeological processes in NT shale gas basins, which will inform development, regulation and monitoring of unconventional gas extraction.

Water Use

The Inquiry finds with respect to Water Use, that:

- unconventional gas extraction has water requirements for drilling and hydraulic fracturing that are small in the context of many other licenced water uses, but which need to be managed carefully to ensure sustainability at a local or catchment/aquifer scale. Conflict with other water users can be reduced by the use of saline ground water or recycled water where feasible;
- water allocation to gas extraction activities including hydraulic fracturing should be transparent, based on sound knowledge of the sustainable yields of aquifers or surface waters, and balanced with the requirements of other water users and environmental benefit. Within the NT, this is probably best done under the Water Act, and where possible within the context of regional water allocation plans;
- the NTG, with the support of industry, should improve knowledge of aquifers and ground water systems in regions where current knowledge is poor and where development of the gas extraction industry is most likely to occur, in order to support evidence-based water allocation as the industry develops over the next two decades. Relevant data collected by industry during exploration and extraction should contribute to building this knowledge base; and
- the NTG and industry should work together to develop, promote and mandate leading practice in water use for hydraulic fracturing, including recycling of flowback water and the preferential use for fracturing fluid of ground water that is unsuitable for human, stock or other beneficial use.

Chemical Use

The Inquiry finds with respect to Chemical Use, that:

- chemicals used during hydraulic fracturing generally pose a low environmental risk, providing that leading practice is applied to minimising surface spills and managing flowback water after fracturing. Public concern about chemical use will be reduced by a transparent, full disclosure policy;
- the NTG should formalise the ban on BTEX chemical use in hydraulic fracturing; implement a process to develop and periodically review a list of other prohibited chemicals as further information about environmental and health risks is available; and work with industry to promote leading practice in minimising the use of chemical additives; and
- the NTG should formalise the requirement for full public disclosure of chemicals used in fracturing fluid and develop a standard format for such disclosure in accordance with the SECR recommendations; and

- public transparency could be improved through making information available through a purpose-designed Web portal that maps the location of wells and fracturing events, and displays chemical information in formats that are accessible to the general public.

Waste Water

The Inquiry finds that with regard to Waste Water:

- waste water management issues are similar to many other mining and industrial processes, although treatment of produced water following fracturing may have some unique elements. On-site treatment and recycling are desirable where possible, but the use of reinjection for waste water disposal will require further investigation to test whether it can be applied in Australia.
- NTG and industry should work together to develop a common understanding of “leading practice” for the management of waste water from unconventional gas activities. This may include developing guidance for preferred approaches in different biomes and climate regimes including, for example, the acceptable risk level for extreme rainfall or flood events;
- NTG should consider making on-site petroleum activities subject to the Waste Management and Pollution Control Act, with appropriate arrangements between leading and co-regulatory agencies to maintain a one-stop-shop approach for industry;
- NTG should work with industry and research agencies to support the development of improved technology for treatment and recycling of waste water from unconventional gas extraction, and promote or mandate recycling for hydraulic fracturing where feasible; and
- as the NT gas industry develops, the NTG should investigate whether economic viability may be enhanced by the development of suitable licenced waste treatment facilities within the Territory.

Fugitive Emissions

The Inquiry finds with respect to Fugitive Emissions, that:

- accurate monitoring of, and accounting for, fugitive emissions during unconventional gas production - including during well completion and following well closure - are critical to understanding life-cycle greenhouse gas emissions. Reduced emission completions (“green completions”) will contribute to minimising fugitive emissions;
- the NTG should mandate the use of flaring as the minimum standard for managing fugitive emissions during well completion following hydraulic

fracturing, and work with industry and other Australian jurisdictions to promote the uptake of “green completion”; and

- the NTG and industry within the NT should encourage and cooperate with studies that seek to improve atmospheric monitoring of fugitive methane emissions, including pre-development baseline measurements.

Noise

The Inquiry finds with respect to Noise, that:

- noise is one of a number “nuisance” impacts associated with unconventional gas extraction, although noise impacts occur primarily for a limited time during drilling and fracturing, and may not be a significant factor in most remote locations;
- for a variety of reasons including protection of human health, the Government could consider setting minimum “setback” distances between gas wells and specified features including living area boundaries. Alternatively this could be managed through risk assessment during environmental impact assessment processes; and
- noise is an environmental impact and risk that should be addressed in the operator’s Environment Plan required for project approval (DME submission, Attachment D, pp105).

Monitoring Requirements

The Inquiry found with respect to Monitoring Requirements, that:

- robust monitoring regimes will be crucial to the effective management and regulation of a developing unconventional gas industry in the NT, and that monitoring requirements in addition to those for standard regulatory compliance should be carefully considered;
- NTG should establish a multi-agency working group that will collaborate with industry to establish standards and protocols for key monitoring programs associated with the development of an unconventional gas industry in the NT, particularly relating to ground water quality, hydraulic fracture performance, fugitive emissions, well abandonment and environmental indicators for cumulative regional impacts; and
- monitoring data should be collated in standard formats in a central data repository and, with accompanying analyses and interpretation, be made publicly accessible.

Well Closure and Site Rehabilitation

The Inquiry found with respect to Well Closure and Site Rehabilitation, that:

- application of leading practice for construction and closure can minimise environmental risks associated with decommissioned wells, but the longevity of long-term integrity of decommissioned wells remains poorly understood;
- the NTG should work with industry and other Australian jurisdictions to ensure a consistent understanding of “leading industry practice” in relation to gas well closure and rehabilitation; and leading practice should be regularly reviewed with new or improved standards promptly adopted and mandated as appropriate;
- the NTG should collaborate with industry, other jurisdiction and research agencies to investigate the longevity of integrity in decommissioned wells, and technologies and practices that will minimise long-term risks from old wells;
- the NTG should work with industry to develop a framework for long-term monitoring of wells post abandonment, with clearly defined responsibilities and associated regulation;
- the NTG should consider the establishment of some form of common liability fund to ensure that resources are available for remediation of “orphan” wells; and
- the NT Government should ensure that adequate systems are in place for the long-term maintenance of comprehensive data for the location, condition and geological profile for all exploration and production gas wells; and that such data is readily available to all relevant stakeholders.

Induced Seismicity

The Inquiry finds that with respect to the potential for Induced Seismicity:

- there is a low risk of seismicity of an intensity that will be felt or cause damage at the ground surface, but risks from induced seismicity can be minimised through leading practice planning, management and monitoring during fracturing operations;
- a seismicity risk assessment should be required as part of the Environmental Plan process for approval of fracturing or waste water injection operations;
- NTG in collaboration with industry, should establish “traffic light monitoring” thresholds to enable real-time response to any seismicity events occurring during hydraulic fracturing operations; and
- NTG should ensure that information relating to fault structures, geological stresses and seismicity gained during exploration and operations is made publicly available by operators to improve scientific understanding and the knowledge base for Australian basins. This may best be done through referral to the COAG Energy Council with the proposition that Geoscience Australia host a national data repository.

Annex G: Acronyms

Acronym	
ACOLA	Australia Council of Learned Academies
AFANT	Amateur Fishermen's Association NT
ALARP	As Low As Reasonably Practicable
ALEC	Arid Lands Environment Centre
API	American Petroleum Institute
APPEA	Australian Petroleum Production and Exploration Association
ATSE	The Australian Academy of Technological Sciences and Engineering
AWA	Australia Water Association
BCA	Business Council of Australia
BOP	Blow-Out Protector
BTEX	Benzene, Toluene, Ethylbenzene, Xylenes
CAS	Chemical Abstract Service
CBL	Cement Bond Log
CCA	Council of Canadian Academies
Cl	Chlorine
CLC	Central Land Council
CO₂	Carbon dioxide
COAG	Council of Australian Governments
CSE	Chief Scientist and Engineer (NSW)
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DLRM	Department of Land Resource Management
DME	Department of Mines and Energy
DMITRE	Department of Manufacturing, Innovation, Trade, Resources and Energy
DOE	Department of Environment
ECNT	Environment Centre Northern Territory
EDO	Environmental Defender's Office
EIA	Environmental Impact Assessment
EIR	Environmental Impact Report
EIS	Environment Impact Statement
EP	Environment Plan

EPA	Environment Protection Authority
EPBC Act	<i>Environment Protection and Biodiversity Conservation Act</i>
GAB	Great Artesian Basin
GHG	Greenhouse Gas
GWP	Global Warming Potential
H₂S	Hydrogen sulphide
IAHNT	International Association of Hydrogeologists NT
IEA	International Energy Agency
LNG	Liquid petroleum gas
MSDS	Material Safety Data Sheet
MNES	Matters of National Environmental Significance
MOU	Memorandum of Understanding
NICNAS	National Industrial Chemicals Notification and Assessment Scheme
NLC	Northern Land Council
NOI	Notice of Intent
NORM	Naturally Occurring Radioactive Material
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
NSIRP	Nova Scotia Independent Review Panel
NSW	New South Wales
NT	Northern Territory
NTCA	NT Cattlemen's Association
NTG	Northern Territory Government
NTGS	Northern Territory Geological Survey
PMSEIC	Prime Minister's Science, Engineering and Innovation Council
QLD	Queensland
RSRAE	Royal Society and Royal Academy of Engineering
SA	South Australia
SANTOS	South Australia Northern Territory Oil Search
SCER	Standing Council on Energy and Resources
SOE	Statement Of Objectives
STRONGER	State Review of Oil and Natural Gas Environmental Regulations
SPE	Society Petroleum Engineers
TOR	Term of Reference

USA	United States of America
VOC	Volatile Organic Compound
WA	Western Australia
WBM	Water-Based Mud

Annex H: CSIRO Fact Sheets

The following fact sheets, referred to in Chapter Three, are produced by the CSIRO:

- Shale Gas in Australia
- Shale Gas Production

Australia's shale gas resources

Shale gas has the potential to change the global energy market. Already, it has transformed the energy sector in the USA, positioning the USA as a potential net exporter rather than importer. Worldwide interest in shale gas has increased, and large shale gas reserves have since been identified in countries in Europe and Asia, as well as Australia.

Australia's shale gas potential

There is currently limited commercial production of shale gas in Australia and the full extent of resources has not yet been ascertained. Initial evaluations indicate that our shale gas resources have the potential to significantly contribute to the Australian energy portfolio. The US Energy Information Administration (US EIA) estimates that 'technically recoverable' shale gas resources in Australia are 396 trillion cubic feet (tcf). One tcf is approximately equivalent to Australia's annual domestic gas usage. Western Australia (WA) alone was estimated to be holding the fifth largest reserves of shale gas in the world - approximately double the amount of gas held in WA's offshore conventional fields.

Currently the most economically viable locations for production in Australia are onshore sedimentary basins containing existing (or previously producing) conventional reservoirs that are well characterised and already host the associated infrastructure. With continued improvements to drilling and reservoir stimulation technologies, and increasing demand and energy prices, more basins are likely to become targets for exploration. Both small and large national and

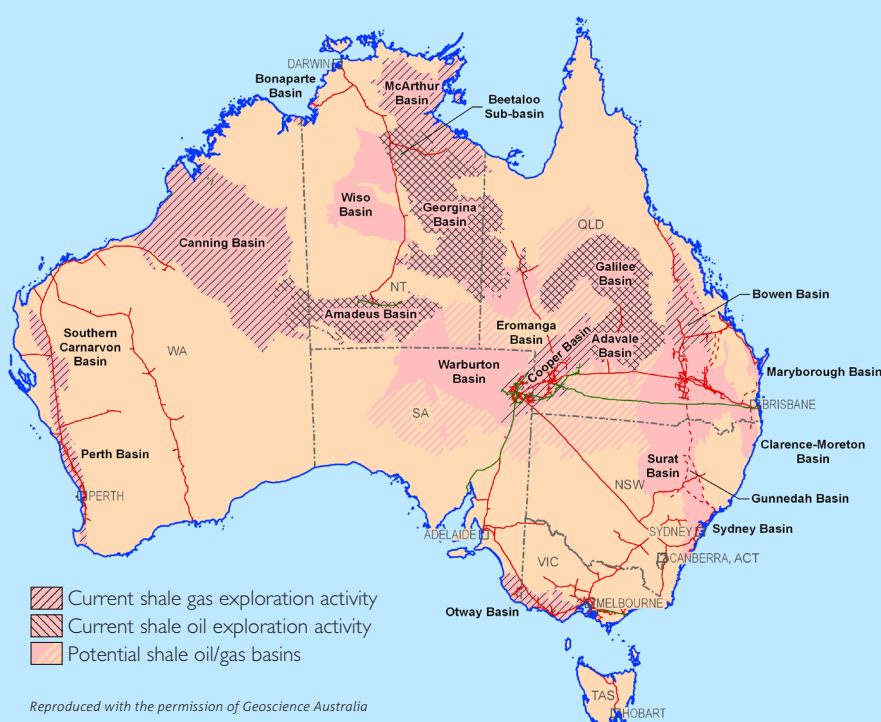
international companies are exploring in various Australian basins for shale gas and/or shale liquids.

Australian shale gas reserves

In Australia, exploration mainly targeting shale gas is being undertaken in the following basins:

- ♦ **COOPER (QLD, SA)** The Cooper Basin stands out as the most prospective and commercially viable region for shale gas development in Australia and has had most of the activities to date. The EIA estimates 342 tcf of GIP (gas-in-place) with a risked recoverable amount of 85 tcf. The basin spans 130,000 square kilometres (km²) and is Australia's most mature onshore region with production of conventional oil and gas over the last 40 years. An extensive pipeline network is already in place, supplying gas to SA, NSW, Qld and Victoria. While conventional production has been declining, the basin's unconventional potential, particularly shale gas, has sparked much interest from Australian and international explorers.
- ♦ **GEORGINA (QLD, NT)** The Georgina Basin is a region of proven oil potential with target horizons ranging from 300 metres (m) to 1000 m. It is a sparsely explored green field area which has all the attributes of a productive hydrocarbon province.
- ♦ **GALILEE (QLD)** The shale in the Galilee Basin has long been recognised as a potential hydrocarbon resource. The shale has exceptionally high organic matter content, a uniform thickness (~35 m), extensive fault-related natural fracturing and good isolation from aquifers. Water wells drilled over the last century have found evidence of oil and gas. In comparison to the other sedimentary basins of similar age the Galilee Basin, and in particular the northern part of the basin, remains relatively unexplored with respect to conventional petroleum, coal seam gas and coal. The major challenge for any energy project in the Galilee Basin will be the significant investment required in infrastructure to access markets.

AUSTRALIAN BASINS WITH SHALE GAS POTENTIAL



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- ♦ **BOWEN (QLD)** The Bowen Basin in eastern Queensland occupies about 160,000 km², the southern half of which is covered by the Surat Basin. It has a maximum thickness of about 10,000 m. Over 100 conventional hydrocarbon accumulations have been discovered in the Bowen Basin, of which about one third are producing fields. The Bowen Basin also has vast coal resources, with major open cut and underground coal mines in the north of the basin. Large volumes of methane gas have been found at shallow depths in the north and has potential for coal seam gas developments.
- ♦ **SYDNEY BASIN (NSW)** The Sydney Basin straddles Australia's central eastern coast in New South Wales. The basin covers 64,000 km² and is both onshore and offshore. The Sydney Basin is part of a major basin system that extends over 1,500 km from the Bowen Basin in Queensland through to the Gunnedah Basin in NSW. Over 100 wells have been drilled in the onshore Sydney Basin. The onshore basin contains rich coal deposits with associated natural gas and minor oil shows.
- ♦ **CANNING (WA)** The Canning Basin in the north of Western Australia is made up of several sub-basins. The onshore portion covers 470,000 km². The area is remote, with a low population density and little or no industrial activity and a limited road network meaning any oil and gas production would require significant investment in infrastructure.
- ♦ **ONSHORE PERTH BASIN (WA)** The Perth Basin is north-south trending hugging the south-western coast of Western Australia. The onshore portion extends over an area of about 32,000 km² and contains a number of conventional oil and gas fields which provide gas to the Perth market via two pipelines. The proximity to the gas market in Perth, 200-300 km south, and a tightening gas supply has made new sources of gas commercially attractive.
- ♦ **BEETALOO SUB-BASIN (NT)** The Beetaloo Basin, located around 500 km southeast of Darwin, has been identified as one of the few remaining virtually unexplored, onshore sedimentary basins in the world. The basin is more than 3000 m thick and there is evidence that both unconventional and conventional hydrocarbons are present. The current pipeline is too small to be of any significant use for the transport of gas and trucking and rail appear to be the first option to transport products.
- ♦ **McARTHUR BASIN (NT)** The McArthur Basin is a petroleum frontier basin with no prior shale gas activity. There are indications of oil and gas in the basin. The target for shale

gas is Barney Creek Formation which has both conventional and unconventional prospects. There is an existing 700 km pipeline from the McArthur River to Darwin and access to the Carpentaria Highway.

Other prospective basins include the Amadeus (NT, WA), Officer (SA, WA), and onshore Bonaparte (WA) basins.

Australia's shale gas future

While Australia has substantial prospective shale reserves, commercial production of shale gas will require long lead times and long term investments because of the nation's small population, low domestic demand and gas prices and the large infrastructure and transportation costs associated with the remote shale reserves. The bulk of future Australian shale gas is likely to be exported as liquefied natural gas. Therefore the feasibility of the resource needs to be carefully assessed and confirmed to warrant the large capital investment that may be needed to establish a successful and viable industry.

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US Energy Information Administration, 2011 'World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States.'

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Bell Potter, 2011 'Australian shale gas overview: a sleeping giant'

http://www.ga.gov.au/oceans/ea_Onshore.jsp

CONTACT US

t 1300 363 400
+61 3 9545 2176
e enquiries@csiro.au
w www.csiro.au

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Shale gas production

Shale gas: porosity, permeability and production

More than half of the Earth's sedimentary rock is made up of shale, a fine-grained rock formed over time from compressed deposits of mud, silt, clay and organic matter. The main characteristic of a shale is its low permeability (a measure of the ability of the rock to allow fluids and gases to pass through it). The geology, geochemistry and geomechanics can be highly variable for different shales and even within a shale.

When the organic matter in shales is heated during burial within the Earth, it is initially transformed into oil and then natural gas, known as shale gas. Shale gas is found at various depths but is typically located deeper than 1000 metres. Shale gas mainly consists of methane (although other gases may be present).

Over time, some of the gas may migrate into an overlying rock unit such as permeable sandstone. This is classified as a 'conventional reservoir' because the gas has moved and is trapped/concentrated in a reservoir where it can be produced using traditional methods.

The generated gas however, may also remain trapped within micropores and fractures of the shale or adsorbed onto clay minerals and organic matter within the shale. Because of the low permeability of shales, shale gas reservoirs need to be hydraulically fractured to allow the gas to flow into the well.

The presence of gas in shale formations has been known for almost 200 years, but the depth at which they occur and their low permeability meant that in the past shale gas has generally been difficult, and hence uneconomical, to extract compared to other natural gas resources. However, with the development

of new technologies in recent years, particularly in horizontal drilling and hydraulic fracturing, operators have been able to achieve economic production; for example in the United States where approximately 20-25 per cent of the total gas consumed now comes from shale deposits.

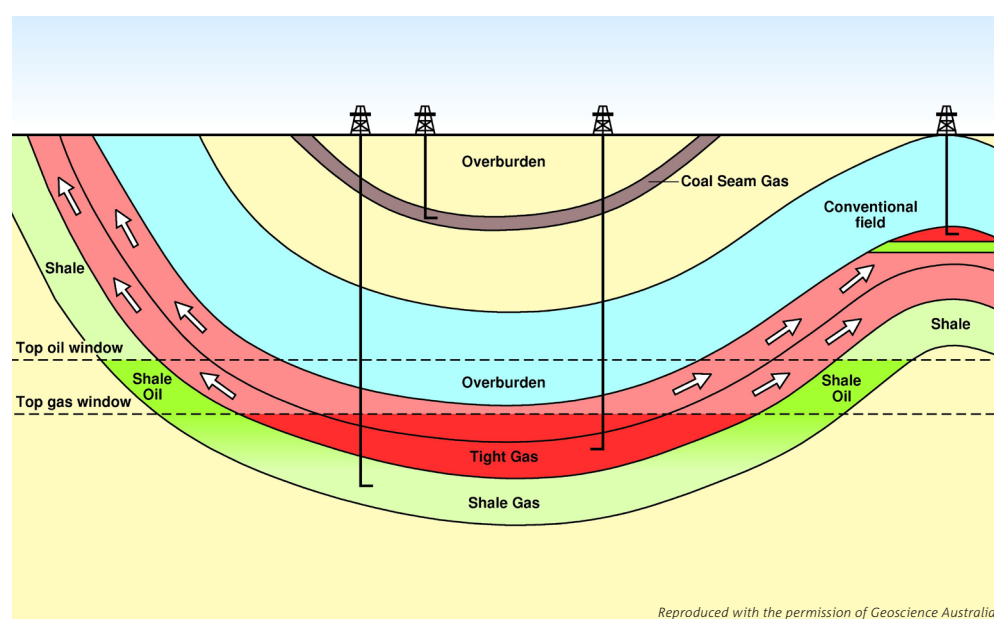
Exploration phase

The exploration phase of shale gas production involves drilling and fracturing vertical wells to verify the presence of gas, characterise it and determine whether it can be economically produced. The number of wells drilled in the exploration phase can range from two to 15 wells in a lease area. Up to 30 wells may be drilled to gain more data on the pressure and geology of the resource.

This data is used for modelling and forecasting the volume of the gas resource, production performance and development economics to determine the long-term viability of production. Shales with commercial reserves of gas are generally more than 100 metres thick and spread laterally over hundreds of square kilometres. Because of this feature, horizontal drilling is generally employed. Once a shale formation is located by vertical drilling, the direction of the drill bit is changed to run horizontally to maximise the wells exposure to the reservoir. In order to be produced, a potential gas bearing shale needs to contain some silt so that the rock is brittle enough to be hydraulically fractured.

Production phase

The number of wells drilled to produce a prospect depends on the lateral extent of the deposit and also on the reservoir pressure. Tight well spacing is sometimes required to lower the reservoir pressure enough to cause significant amounts of the adsorbed gas to be desorbed and released. Recovery of the gas from an individual well can range from 28-40 per cent of the total gas present (compared to conventional wells which drain gas over a larger area and recover up to 60-80 per cent). Historically the average well spacing for vertical wells is 400 metres while spacing between horizontal wells is a function of the shape of the induced fractures, but is often at least 800 metres. Operators aim to increase well spacing to reduce costs and environmental impacts.



This diagram shows a conventional hydrocarbon accumulation on the right, and the spectrum of unconventional hydrocarbon accumulation types in the centre. The arrows show gas migration over geological time.

Multi-lateral drilling (drilling two or more horizontal wells that extend in different directions from the same vertical well bore) is also used to maximise access to shale gas reservoirs.

Because of the low permeability, several hydraulic fracturing treatments are generally applied over time.

Hydraulic fracturing stimulation for shale gas is mostly done in horizontal wells using 'slick water' and sand. Slick water is water mixed with a low concentration of guar (a vegetable gum made from guar beans) which reduces the fluid friction during pumping. The slick water and sand are pumped down the well at sufficient pressure to fracture the shale. The sand holds the fractures open so that the gas can be produced. After the fracturing is complete, part (approximately one third) of the fluid injected flows back to the well. These types of treatments are often done in CSG wells using similar fluids.

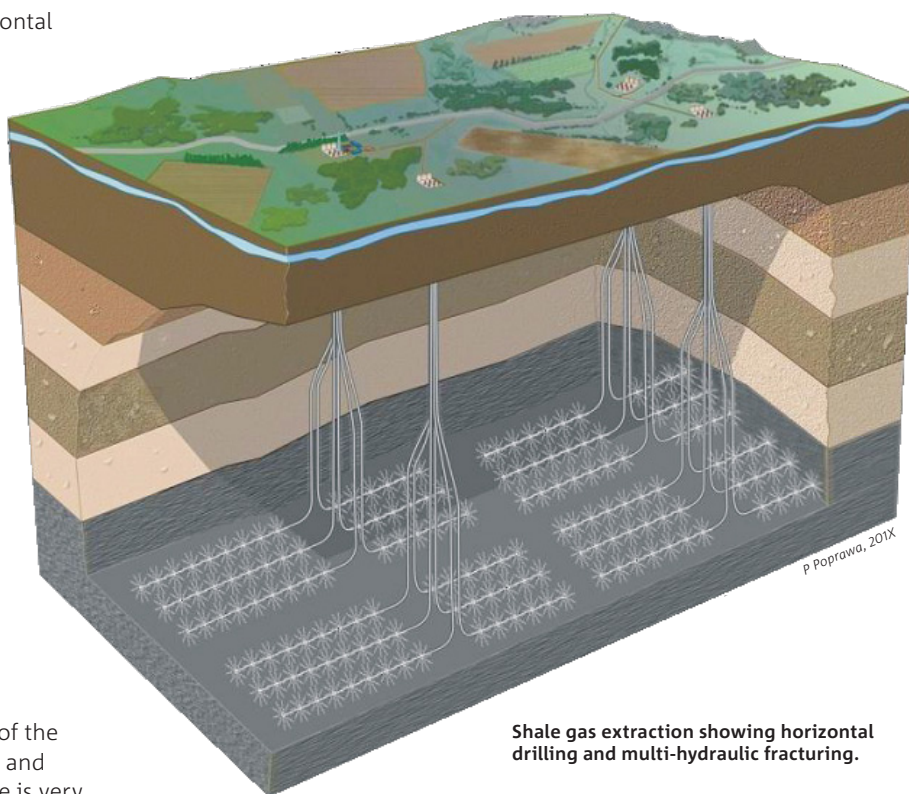
Many fracture stages are employed per well, typically 10-20, spaced out in a horizontal part of the well typically 1-2 km long. The amount of water and sand proppant needed for each fracturing stage is very large (1 million litres or one mega litre per fracture), so this is a potential limitation (ie 20 mega litres per well). Water availability and long distance transport of materials in Australia is a very different logistical and economic prospect than in North America. Flow-back water then has to be dealt with and best practice usually involves transporting it to a treatment site, which needs a large economy of scale to be viable.

Once extraction from a well is no longer economic, sections of the well are filled with cement. This is to prevent gas from flowing up to the surface or into any zones containing water/aquifers. The well is then capped below ground level and buried.

Commercial production considerations

There are a number of factors to be taken into consideration for commercial production of shale gas in the Australian context. Some of these factors include:

- Whether there is a large enough supply to merit the substantial investment in research, technology development, infrastructure and extraction costs.
- Demand needs to be high considering the low gas prices in Australia. However, the local gas prices relative to other energy sources may change, particularly while conventional oil and gas production continues to decline around the globe. This will dictate whether returns from exploiting shale gas will justify the large capital investment required.



Shale gas extraction showing horizontal drilling and multi-hydraulic fracturing.

- The price of gas markets overseas will determine the price in Australia. Currently the local price is low but export prices are high. Any change in this will affect the prospectivity of the resource in Australia.
- Australia has limited pipelines, natural gas liquefaction plants and other infrastructure to support the production, processing and transportation of most of its remote shale gas resources. This will require significant capital investment.
- A well developed, stable and comprehensive regulatory regime is needed to support large scale shale production capacity and at the same time address environmental management, water management, land access and other issues such as air quality, noise impacts, impacts on local communities and waste disposal. Health, safety and environmental concerns associated with shale gas production is currently under study.

These key variables, along with the research and development challenges faced in producing shale gas safely and economically, need to be addressed before the shale gas industry can become a reality in Australia.

REFERENCES

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CONTACT US

t 1300 363 400
+61 3 9545 2176
e enquiries@csiro.au
w www.csiro.au

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