Northern Territory Government

Department of Mines and Energy
Energy Directorate

Submission to Northern Territory Government – Public Inquiry into Hydraulic Fracturing

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AUSTRALIA'S Northern Territory

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Preamble

i) Introduction

The demand-led growth for low emissions natural gas as an energy source locally, nationally and internationally stems from the global quest for energy security and a desire to reduce pollution and greenhouse gas emissions. Natural gas also underpins the Darwin to Katherine grid power supply, with off-grid locations serviced by imported diesel and limited solar energy.

Logically, development of the natural gas industry (both offshore and onshore) forms a key component of the Northern Territory Government's "Framing the Future" vision. The onshore gas industry is seen as a fundamental enabler of the Territory's future economic growth through the provision of employment, regional development and royalty benefits directly to the Territory government. It is also essential to the Territory's and, in part, the nation's energy security.

Considerable onshore shale oil and natural gas resources have been identified in the Territory. The McArthur (including the Beetaloo sub-basin) and Georgina basins host some of the oldest potentially recoverable natural gas resources in the world. New technologies, including hydraulic fracturing, have improved the opportunities to target these "unconventional" oil and natural gas resources.

Exploiting these resources within the constraints of the Territory's limited infrastructure attaches substantial challenges. That the Territory is serviced by the Stuart Highway and a north south gas pipeline is not of itself enough to facilitate economic and safe access to these resources. The climate in the northern basins also constrains exploration for up to six (6) months of the year, limiting the time on ground compared to other jurisdictions. In themselves, these factors will control the level of activity, affording a suitable timeframe for the Department of Mines and Energy (DME) to continue to enhance its already robust regulatory framework and create new world-class contemporary legislation.

The hydraulic fracturing technology used to release oil and natural gas from shale formations is not new technology. It has been used globally since the 1950s. In the Territory it has been used for 40 years without environmental incident; and substantial advances in well integrity technology, the key component in subsurface aquifer protection, have been made.

The innovation in the process that has allowed access to previously unreachable resources is the introduction of directional (horizontal) drilling, resulting in a significant increase in activity in the search for and production of shale oil and gas. It is this level of activity that has raised community concerns about the potential environmental and social impacts of shale oil and gas production.

DME supports the initiative to commission the Inquiry into the potential environmental issues associated with hydraulic fracturing (the Inquiry) and considers that this can only serve to support DME's continued enhancement and strengthening of the regulatory framework in place to manage and mitigate against adverse environmental outcomes. DME also welcomes the opportunity to provide a submission to the inquiry.

In discussing hydraulic fracturing, the submission refers to "shale gas", "shale gas and oil" and "shale hydrocarbons" interchangeably, as well as references to "tight gas": it should be noted that the technology of hydraulic fracturing and associated issues are the same for natural gas and oil. It is also important to point out that there is a clear scientific distinction between shale oil and natural gas, and Coal Seam Gas (CSG). Not only are the geological formations clearly differentiated, with shale oil and gas deposits typically occurring at significantly greater depths below the earth's surface, but the methods of extraction are materially different.[1] Further, there is no legislative basis to support CSG activities in the jurisdiction.

ii) Scope of DME responsibilities

DME has responsibility for supporting the development of petroleum activities in the Northern Territory. This includes the provision of geological and scientific information on prospectivity in the Territory which in turn supports its activities in promoting opportunities and attracting investment. It also has the responsibility for the regulation of onshore petroleum activities across the jurisdiction. In order to guard against industry capture and conflicts of interest, DME maintains a strict separation between its industry support and promotion functions, and regulatory functions.

While DME keeps itself abreast with international leading practice in petroleum industry developments, it does not have the capacity to provide expert advice and analysis of petroleum activities and any consequent environmental impacts in other jurisdictions throughout the world. For its own purposes it relies on external expert advice, and where appropriate it will refer the Inquiry to these sources.

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1 Attachment A

Although not DME's legislative responsibility, as per its Guideline "Assessment Process for Onshore Petroleum Drilling, Workover and Stimulation Application", Cultural Clearances must be addressed through the operator's stakeholder consultation process and reported in their activity environment plan for assessment. DME refers all environment plans to the EPA for comment before approval is granted.

While in the NT (and Australia), the landowner owns the topsoil and has no claim on the resources that may lie below, under the DME Guideline "Assessment Process for Onshore Petroleum Drilling, Workover and Stimulation Application", operators must carry out an extensive consultation process with all stakeholders before approval for a petroleum activity is granted. Operators are expected to address all stakeholder concerns to a point where all parties are "reasonably satisfied". If some matters remain unresolved, before approval is granted, DME will act as facilitator, until a common level of agreement is reached. In addition, a Model Access and Compensation Agreement which will be co-badged by the Australian Petroleum Production & Exploration Association (APPEA) and the Northern Territory Cattlemen's Association (NTCA) is near completion. This will guide both pastoral lessees and oil and gas proponents in developing their land access agreements.

In respect of land subject to the Aboriginal Land Rights Act and the Native Title Act, land access negotiations and agreement form part of the application negotiation processes.

DME supports the 6 principles identified by the SA Government[2] for the development of a best practice regulatory framework:

Certainty: The regulatory objectives are uniform, clear, and predictable for all stakeholders

Openness: Stakeholders are appropriately consulted on the establishment of the regulatory objectives

Transparency: The regulatory decision making processes are visible and comprehensible to all stakeholders and industry performance in terms of compliance with the regulatory objectives is clear to all stakeholders

Flexibility: The level of regulatory scrutiny, surveillance and enforcement needed to ensure compliance is determined on the basis of individual company compliance capability and the outcomes to be achieved

Practicality: The regulatory objectives are achievable and measurable

Efficiency: The compliance costs imposed on both government and the licensee by the regulatory requirements are minimised and justified. Negative impacts on communities are minimised, and licensees remain liable for the cost of their impacts. Furthermore, an appropriate rent (Royalty) is paid to the community from the value realised from the development and production of its natural resources.

DME is the lead agency for petroleum activity regulation in the Territory and operates on a one-stop-shop model, providing proponent's a single government portal. This has been identified by the Australian Productivity Commission as the most efficient regulatory approach and is consistent with Northern Territory Government (NTG) policy.[3] For the purposes of lodging applications, operators have one point of contact with co-regulatory objectives and requirements co-ordinated by DME. This ensures that approval processes can be progressed in parallel rather than in series. It also provides a consistency of approach which builds confidence with co-regulatory agencies, other stakeholders and the public.

iii) Structure of the Submission

This submission largely follows the structure of the Inquiry's Terms of Reference. Relevant areas of DME have provided input, information and advice across the range of issues. Every effort has been made to include all the data and information available within DME, but should the Inquiry require further information, including the participation in any public hearings, DME will assist wherever possible.

The submission makes extensive use of footnotes and appendices, and includes links to publicly available information on the agency's website.

iv) Summary of the Submission

The submission provides a history of the use of hydraulic fracturing in the Northern Territory together with an indication of known planned projects that are likely to include hydraulic fracturing, and an overview of prospectivity in the Territory for unconventional resources where hydraulic fracturing may be deployed.

Known and potential environmental impacts are examined on the basis of local, national and international experience and knowledge. This is complemented with an analysis of areas of continued scientific research and the implementation of new technologies designed to reduce environmental impacts – for instance the interplay between hydraulic fracturing and hydrology, and the use of multiple well pads.

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2 SA Department of Manufacturing, Innovation, Trade, Resources and Energy (DMITRE), December 2012, Roadmap for Unconventional Gas Projects in South Australia, p.136

3 Australia's Productivity Commission, 2009, Research Report – Review of Regulatory Burden on the Upstream Petroleum (Oil and Gas) Sector, Commonwealth of Australia.

The submission provides a detailed description and analysis of the regulatory framework in the Northern Territory for petroleum activities with a specific focus on hydraulic fracturing.

DME supports the conclusion of the Australian Council of Learned Academies (ACOLA) that in relation to hydraulic fracturing:

> "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, groundwater 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."[4]

The current regulatory system administered by DME is very robust and accords with leading practice. DME also considers that the current one-stop-shop "single portal" framework that is in place in the Territory is working effectively, with excellent levels of co-ordination and cooperation between relevant government agencies. Nevertheless, it recognises the need to maintain a continuous regulatory review process in order to ensure that the framework keeps pace with new knowledge, new technologies and new risks. In this context, DME is currently reviewing the regulatory framework and is developing new Environment Regulations and Resource Management Regulations which will replace the current Schedule of Onshore Petroleum Exploration and Production Requirements (2012) (the Schedule).

[4] Australian Council of Learned Academies (ACOLA), May 2013, Engineering Energy: Unconventional Gas Production. A study of Shale Gas in Australia, p.16

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1. Impact of hydraulic fracturing (hydraulic stimulation/fraccing) to date and ongoing in the Northern Territory

1.1 Introduction

Australia has significant potential to become one of the next countries with commercially viable shale gas and shale oil production. Basins in the Northern Territory, such as the McArthur Basin (including the Beetaloo Sub-basin) and Georgina Basin host some of the oldest potentially recoverable unconventional gas resources in the world.[5]

In Australia, drilling for hydrocarbons has over a 50-year history and hydraulic fracturing has been undertaken throughout most of this period; for example, 70 wells in the Cooper Basin have been hydraulically fractured. Since 2010, 50 wells targeting shale and tight gas have been drilled, but less than 15 wells have been stimulated by hydraulic fracturing.[6]

In the Northern Territory, hydraulic fracturing has been taking place since 1967 but mainly as a process to enhance hydrocarbon production from conventional reservoirs with vertical wells. Only since 2011 has fracturing been carried out during exploration for unconventional hydrocarbons (by PetroFrontier through horizontal drilling and Falcon Oil & Gas through vertical drilling).

1.2 Hydraulic fracturing in the West Mereenie area

Of the 22 wells drilled in the area, between 1991 and 1994, hydraulic fracturing was applied to 7 wells to stimulate production. Santos and its predecessors targeted various zones in the Pacoota Sandstone between 4300 and 4800' (1310.6 – 1463m) with a fracture zone generated of 78 to 245' (23.8 – 74.7m) maximum. The identical treatment chemicals were used in each of the fracture stimulations and no adverse issues were reported.

1.3 Hydraulic fracturing in the East Mereenie area

Santos drilled 43 wells in East Mereenie and fracturing processes were carried out on about 20 wells to stimulate production. The first fracturing episode was in 1967 but generally took place between 1992 and 1996. The Pacoota Sandstone was targeted at depths between 4600 and 5000' (1402.4 – 1524.4m) and fractures zones of 93' to 245' (28.4 – 74.7m) maximum were produced. The identical treatment chemicals were used as in the West Mereenie stimulations and no problems were reported.

1.4 Hydraulic fracturing in Palm Valley

In the period 1973 to 1975, Magellan Petroleum operated 11 wells in Palm Valley. Hydraulic fracturing was used to stimulate production in about five wells. The Stairway, Horn Valley and Pacoota Formations were the targets at depths between 5700 and 7200' (1737.4 – 2194.6m). Various chemical treatments were applied and success rates were mixed. No major issues were reported.

1.5 Hydraulic fracturing in the Dingo area

Pancontinental fractured one well in the Dingo area in 1984. The Arumbera Sandstone was the target and pre-fracturing evaluations only are available.

1.6 Hydraulic fracturing during unconventional hydrocarbon exploration

In 2011, Falcon Oil & Gas undertook a fracturing program during the re-entry and deepening of the vertical well Shenandoah-1 in the Beetaloo sub-basin (McArthur Basin). A detailed fracture and environmental report is available[7] and no problematic issues were reported.

PetroFrontier undertook a horizontal drilling program for wells Owen 3H, Baldwin 2HST 1 and MacIntyre 2H in the southern Georgina Basin in 2012. Hydraulic fracturing was applied to the horizontal sections of the well bores. Final reporting has not yet been completed but during the hydraulic stimulation program of the Baldwin-2HST1 well, a shallow casing failure occurred and as a result, PetroFrontier was unable to complete the program. Hydrogen sulphide was detected in the other 2 wells and although fracturing was successful, MacIntyre 2H was suspended. Technical aspects of this hydraulic fracturing program has established that water will be adequate to stimulate wells in future, without addition of chemicals[8].

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5 EIA/ARI World Shale Gas and Shale Oil Resource Assessment, 2014
6 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013
7 PR2012-0011, Northern Territory Government
8 http://www.petrofrontier.com/

1.7 Future plans likely to include hydraulic fracturing in the Northern Territory

Currently DME has no requirement during drilling work program submission for the inclusion of a statement to carry out hydraulic fracturing. If the operator is targeting shale formations, there is a reasonable degree of certainty that fracture stimulation will occur at a later date. In view of this, before the commencement of drilling, the operator is advised to carry out activities such as water analysis for a pre-environmental study. This is required by DME as part of the "before-during-after" environmental assessment. In the case of targeting unconventional prospects, it is highly possible that hydraulic fracturing will take place to test the reservoir.

Falcon Oil & Gas with their new joint venture partners, Origin Energy and Sasol, plan further work in the Beetaloo sub-basin. This includes 5 horizontal wells and 1 vertical well each with hydraulic fracture stimulation. Origin Energy will take over as operator of the work program.

Central Petroleum intends to pursue unconventional exploration in central Amadeus, southern Georgina and southern Amadeus Basins, in collaboration with joint venture partners Santos and Total. Targeting unconventional hydrocarbons is expected to involve the use of hydraulic fracturing for production testing.[9]

Santos will carry out hydraulic fracturing in up to 8 wells in the Mereenie area from 2014 as part of a program to stimulate production from conventional reservoirs.[10]

PetroFrontier will be active in the southern Georgina Basin and in collaboration with joint venture partner Statoil. This will bring Statoil's unconventional technical and operating experience to the Northern Territory (actively involved in Marcellus, Eagle Ford and Bakken plays in North America). Statoil is gradually increasing its working interest in the PetroFrontier permits. Of 5 vertical test wells to be drilled in 2014, three of the wells will be cased for future hydraulic stimulation and production testing.[11]

Tamboran Resources will test unconventional targets during 2014-2016 around the Tanumbirini prospect in the McArthur Basin, with Santos. Testing of unconventional targets will also take place from 2014 around the Davis prospect in the Ngalia Basin. At this time, it is not known whether or not these wells will be fracture stimulated.[12]

Imperial Oil & Gas holds granted permits and applications in the eastern McArthur Basin. If proven to contain shale gas, the final year of the work programs in each permit includes the drilling and evaluation of a deviated or horizontal well involving fracturing and gas production testing.[13]

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9 Latest company presentation, CPL, 04/2014 http://www.centralpetroleum.com.au/

10 Environment plan summary, Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013.

11 http://www.petrofrontier.com

12 http://www.tamboran.com

13 http://www.empireenergygroup.net

2. Unconventional oil and gas prospectivity

In March 2014, the Northern Territory Geological Survey released a 242 page volume on the Territory's known petroleum geology, resources and potential.[14] This is the most current reference source on the Territory's onshore petroleum potential, and the brief descriptions of individual basins outlined below are largely sourced from this document.

2.1 McArthur Basin

There is considerable potential for unconventional gas and oil plays in the McArthur Basin. The main prospective shale units are the Barney Creek Formation (McArthur Group), the Velkerri and Kyalla Formations (Roper Group, Beetaloo Sub-basin). Other units with potential for tight gas and basin-centred gas accumulations (BCGA) are the Reward Dolostone (McArthur Group) and, the Bessie Creek and Moroak Sandstones (Roper Group).[15]

The Barney Creek Formation is a significant unconventional shale gas and oil prospect and unconventional gas is also reservoired in relatively low permeability reservoirs in the Lynott Formation and Reward Dolostone. Recent exploration by Armour Energy in the Batten fault Zone near Borroloola has focussed on conventional accumulations, but also demonstrated the existence of live hydrocarbons in the Barney Creek shales.[16]

The Beetaloo Sub-basin is considered to be one of the most promising regions in the NT for shale oil and gas. The sub-basin is also prospective for conventional petroleum, although no significant accumulations have been identified to date. Recent focus has been on the unconventional resources of the sub-basin, and several wells – in particular Shenandoah-1A (Falcon Oil and Gas) – have confirmed the shale oil and gas potential of the middle Velkerri and Kyalla formations, and the basin-centred gas accumulation (BCGA) potential of the Bessie Creek and Moroak sandstones.

Shale oil risked recoverable resources in the Velkerri and Kyalla units are 0.82 billion barrels (Bbbl) condensate and 3.83 Bbbl oil. Shale gas risked recoverable resources of 43.7 trillion cubic feet (TCF) have been estimated for associated gas, wet gas and dry gas.[17]

The McArthur Basin is prospective for petroleum over large areas that remain virtually unexplored, which extend in the subsurface over nearly a quarter of the Territory.

2.2 Georgina Basin

Unconventional oil and gas play potential exists over large areas of the southern Georgina Basin. The Arthur Creek Formation is currently being investigated as a potential shale oil or tight gas reservoir. Two horizontal wells (Baldwin 2 HST1 and MacIntyre 2H) in the lower Arthur Creek Formation encountered heavy gas readings. Owen 3H, another horizontal well, demonstrated potential for shale oil from the same interval.[18]

Lower Arthur Creek shales have risked recoverable resources of 0.28 Bbbl of condensate and 0.71 Bbbl of oil. Risked recoverable shale gas resources are estimated to be 12.8 TCF for associated gas, wet gas, and dry gas.[19]

2.3 Amadeus Basin

Numerous conventional discoveries exist in the Amadeus Basin, and the wells of the Mereenie, Palm Valley and Dingo fields have been hydraulically fractured to enhance production. The concept of conventional fracturing is similar to that of unconventional.

Unconventional resources could include shale oil, oil sands, shale gas and tight gas. The most prospective reservoir units are Stairway Sandstone-hosted shales, Horn Valley Siltstone and Pacoota Sandstone-hosted shales.[20]

Best estimate recoverable resources for the Horn Valley Formation is 16 TCF dry gas.[21]

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14 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
15 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
16 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
17 EIA/ARI World Shale Gas and Shale Oil Resource Assessment, 2014
18 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
19 EIA/ARI World Shale Gas and Shale Oil Resource Assessment, 2014
20 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
21 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013

2.4 Wiso and Ngalia Basins

The Wiso Basin is effectively unexplored, but the southern part of the basin, known as the Lander Trough, is believed to be an analog of the southern Georgina Basin, with likely unconventional gas and oil potential. Areas further north in the basin form a relatively thin carbonate platform with limited unconventional gas potential.[22]

The Ngalia Basin is generally underexplored and its potential for unconventional petroleum is largely speculative. Limited drilling has shown evidence for hydrocarbon generation, but no viable petroleum systems have yet been identified.[23]

2.5 Pedirka and Eromanga Basins

Extensive Permo-Triassic coal measures such as the Purni Formation, of the Pedirka Basin have coal bed methane (CBM) potential. The Purni Formation is also prospective for shale gas. However commercial exploitation of these resources would need to take into account major aquifers in the Great Artesian Basin.[24]

In the Eromanga Basin, The Toolebuc Formation and the overlying Allaru Mudstone are the most prospective.[25] Best estimate recoverable resources for the Toolebuc Formation in Eromanga are 82 TCF dry gas. For the Purni Formation in Pedirka, the figure is 43 TCF.[26]

22 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
23 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
24 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
25 Munson T.J., Petroleum Geology and Potential of the Onshore Northern Territory (Report 22), 2014
26 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013

3. Environmental impacts from fracturing: Northern Territory, Australia and International

Issues that could potentially be caused by hydraulic fracturing include induced seismicity and groundwater contamination of which none have been reported in the Northern Territory. Issues that are an unavoidable but controllable part of unconventional drilling (and hydraulic fracturing) include landscape impacts, water consumption, the makeup of fracture fluids and waste water disposal. The activities of operators in the Northern Territory are regulated to such a level that potential impacts on the environment are brought to ALARP ("as low as reasonably practicable").

3.1 Induced seismicity

Hydraulic fracturing produces measurable signals but with extremely low magnitude in non-faulted environments. When a fracture engages a typical formation fault, the magnitude is slightly higher. The creation of a moderate magnitude seismic event is regarded as a very remote possibility due to the ease of identifying larger faults on seismic surveys.[27] BP states that this fault identification process is conducted prior to fracturing operations. [28]

A study by Durham University states that there are only 3 recorded incidents of felt seismicity that are probably induced by hydraulic fracturing – in the USA, Canada and in the UK. The largest was in Canada's Horn River with a 3.8 magnitude. It also notes that most felt seismicity from human activity (198 recorded incidents) was due to activities such as conventional oil/gas field depletion, waste-water injection and geothermal energy processes.[29]

The Australian Academy of Technological Sciences and Engineering (ATSE) concurs with these findings but notes that currently in Australia, no seismic risk data for shale gas operations exists. It suggests that to minimise the potential of induced seismicity, it will be important to follow best practice mitigation through monitoring the volume and pressure of reinjected produced water and gaining better knowledge of fault structures near shale gas operation sites.[30] It should be noted that hydraulic fracturing is currently taking place in the CSG industry in Australia with no reports of induced seismicity.[31] (Note that CSG – coal seam gas – is also known as coal bed methane or CBM in overseas jurisdictions.)

Several fracture monitoring technologies including microseismic arrays and tiltmeters are currently in use and under development. Pressure sensors loaded into the production casing along which fractures are generated can be used to monitor the growth of fractures. These will be employed by Santos as noted in its 2014 drilling/ environmental plan for the Northern Territory. Santos also states that given the low population density and lack of infrastructure in the area of its operations in the Amadeus Basin, the induction of seismic events is not considered a credible risk.[32]

3.2 Groundwater contamination

Potential groundwater contamination could result from spills of drilling mud; flowback of fracture fluid; leaking fluid from waste-water pipes or ponds; leaks from inadequate cementing of wells; and leaks through geological structures via natural or artificial fractures.[33]

No groundwater issues from the hydraulic fracturing process have been reported according to one major study in the United States. Any environmental impacts have been caused by other drilling operations. These are low in comparison to other pollution factors including natural seeps.[34]

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[27] King, G.E., Hydraulic Fracturing 101: What every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbour and Engineer should know about Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells, SPE, 2012

[28] Unconventional Gas and Hydraulic Fracturing, Issue Briefing 2013-www.BP.com/sustainability

[29] Davies R., Induced Seismicity and Hydraulic Fracturing for the Recovery of Hydrocarbons, 2013

[30] Response to the Inquiry into the Implications for Western Australia of Hydraulic Fracturing for Unconventional Gas, Australian Academy of Technological Sciences and Engineering (ATSE), 2013

[31] Potential Geological Risks Associated with Shale Gas Production in Australia, Australian Council of Learned Academies (ACOLA), 2013

[32] Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013

[33] Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011

[34] King, G.E., Hydraulic Fracturing 101: What every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbour and Engineer should know about Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells, SPE, 2012

State	Study Period	# Wells Producing	# Cases Investigated	Site Related	D&C Related	Frac Related	Production Related	Orphan Well Related	Waste Disposal Related	P&A Related	Unknown
Ohio	26yrs	65,000	185	0	74	0	39	41	26	5	0
Texas	16yrs	250,000	211	0	10	0	56	30	75	1	39

D&C - Drilling and Completion - in Ohio and Texas, due to cement isolation problems

57 of 75 waste disposal-related incidents in Texas were legacy issues with disposal pits that were outlawed in 1969

Orphan well – abandoned upstream oil and gas wells with improper P&A and reclamation

P&A – plugging and abandoning

Of 16,000 multi-fractured horizontal wells in this study, no groundwater contamination was found at any stage of drilling, well construction, hydraulic fracturing or production operations.[35]

In 2004, research into the impact by hydraulic fracturing of CBM (CSG) on groundwater by the US Environmental Protection Agency could find no confirmed cases that could link hydraulic fracturing to well contamination.[36]

Groundwater contamination by methane has been raised as a possible consequence of the fracturing process. However, ACOLA notes that methane occurs naturally in groundwater due to slow migration from deeper gas-bearing strata or from microbial activity. The original source of methane (biogenic or thermogenic) can be distinguished by analysing the isotopic signature of the gas. The Moomba gas field in South Australia was identified in part as a result of the presence of gas shows in the Great Artesian Basin aquifers.[37]

Besides methane contamination, most concern with hydraulic fracturing is water pollution by fracture fluids. In the Northern Territory, no groundwater issues have been recorded from fracturing or other unconventional drilling operations, including those from PetroFrontier's Baldwin 2HST1 well in 2012. Activities in this well were halted after a shallow casing failure occurred during the hydraulic stimulation program along the deep, horizontal section of the well bore. As expected though, the multiple casing design protected the shallow aquifers.[38]

The relatively low level of structural complexity in the McArthur Basin is recognized as a factor which reduces the risk of fractures affecting groundwater.[39] Even so, the groundwater aspect of environmental protection displayed during the drilling of Shenandoah-1A (McArthur Basin, Beetaloo sub-basin) by Falcon Oil & Gas in 2011 is one example of the additional measures needed to prevent water pollution. This was a vertical well drilled to target unconventional hydrocarbons in three geological horizons – the Lower Kyalla, Middle and Upper Velkerri Formations.[40]

Environmental protection procedures put in place included surface casing and cement to isolate the Tindall Limestone Aquifer, which prevented possible contamination by drilling fluid and fracture fluids. The surface casing and cement was extended to include the Antrim Volcanics below the Aquifer. The volcanics themselves would have acted as an additional barrier to any upward fracture propagation and fluid escape from below.[41] The intermediate and production casings at depth were proven by cement bond logs to have provided good cementation, zonal isolation and fluid containment.[42]

The separation distance between the uppermost fracture zone and an aquifer is regarded as another essential component in preventing water contamination.[43] In the case of Shenandoah-1A the separation distance between the Lower Kyalla fracture zone and the Tindall Limestone Aquifer measures over 1300 metres.[44] The recommended separation zone is 600 metres (especially in areas where fracture data is incomplete or absent) based on a survey in 2013 of fracture propagation – both natural (due to igneous activity) and artificial (due to hydraulic fracturing). Upward propagation of fractures is unlikely to exceed 350m[45] and for US shales a figure of 90m has been quoted.[46]

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35 King, G.E., Hydraulic Fracturing 101: What every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbour and Engineer should know about Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells, SPE, 2012

36 Hydraulic Fracturing – Effects on Water Quality, Cornell University City and Regional Planning, 2010

37 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013

38 http://www.petrofrontier.com/

39 Potential Geological Risks Associated with Shale Gas Production in Australia, Australian Council of Learned Academies (ACOLA), 2013

40 PR2012-0011, Northern Territory Government

41 Hydraulic Fracturing – Effects on Water Quality, Cornell University City and Regional Planning, 2010

42 PR2012-0011, Northern Territory Government

43 Davies R.J., et al., Fracking and Aquifers: How Far Up can a Frack Go?, 2013

44 PR2012-0011, Northern Territory Government

45 Davies R.J., et al., Fracking and Aquifers: How Far Up can a Frack Go?, 2013

46 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013

Water studies were carried out on behalf of Falcon Oil and Gas by international environmental consultant AECOM. To date there are no indications that the Shenandoah-1A drilling, re-entry, stimulation or water reinjection has impacted the ground water in any way.[47]

Santos's 2014 drilling/environmental plan comments on the risk to groundwater and the following steps are being put in place to reduce the risk to ALARP (as low as reasonably practicable):

- Well design and construction will provide mechanical integrity to reduce the risk to ALARP
- Pressure testing will confirm that production casing exceeds the maximum allowable operational pressure
- Cement bond logs will confirm the integrity of the cement between the casing
- Pressure safety trip-out systems will be used during fracturing to prevent excess pressure on surface pipework and down-hole casing equipment
- Pressure monitoring will confirm that well integrity is not impacted by fracturing
- Installation of a tubing string post-fracture will provide further isolation of production fluids from aquifers[48]

Concerning any possible fracture propagation into the overlying Mereenie Aquifer, the separation distance between the target formations and the aquifer is over 500m, and the modelled fracture propagation is a maximum of 70m (refer also to sections 1.2 and 1.3). Fracture propagation into the aquifer is therefore unlikely. A water bore baseline assessment has recently been undertaken and this assessment will form the basis of ongoing monitoring of the Mereenie Aquifer in the project area.[49]

3.3 Landscape impacts

Unconventional drilling and hydraulic fracturing processes require well pads and storage for technical equipment, trucks, chemicals, proppant, water and waste-water containers. A typical pad size in Pennsylvania can reach 0.02 km^2 and, there can be multiple wells per pad with well spacing dependent on state regulations. Additionally, as production has an initial high rate and a steep decline profile, gas is often stored on site at the well pad.[50]

The impact on the landscape by unconventional hydrocarbons exploration and production can be viewed as having a similar impact as any industrial activity. However due to the nature of the exploration and production process, multiple wells are needed. The impact on the landscape and the environment can be minimized by grouping wellheads together in clusters with 10 – 30 horizontal wells being drilled from a single site.[51]

Santos has identified the possible impact on stock, wildlife and vegetation in the Amadeus Basin. All activities conducted during the 2014 drilling program will be confined to the cleared well lease with signs and appropriate fencing installed to delineate approved and restricted areas. If flora of conservation significance is present within the area of the well lease, it will be flagged and/or fenced off to prevent disturbance.[52]

3.4 Water consumption

An estimate of water consumption in the Northern Territory and other parts of Australia has been carried out by ACOLA.[53]

Basin	Basin Area (km^2)	Number of shale gas wells	Water needed for fraccing (GL)	Fraccing water per year (GL)	Groundwater sustainable yield (GL/year)	Groundwater abstraction (GL/year)	Water footprint compared to gas footprint
Amadeus	162,294	12,679	190.2	7.6	142	14	26
Georgina	362,638	28,331	425	17	241	64	34
McArthur	198,480	15,506	232.6	9.3	749	9	6
Wiso	138,586	10,827	162.4	6.5	106	4	30

Shale gas basins in the Northern Territory showing the potential number of wells (assuming well space of 800 metres and fairways making up 5% of the basin)

47 PR2012-0011, Northern Territory Government
48 Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013
49 Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013
50 Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011
51 Unconventional Gas, Resources for the Future, Total, 2012
52 Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013
53 Potential Geological Risks Associated with Shale Gas Production in Australia, Australian Council of Learned Academies (ACOLA), 2013

- The estimated volume of water needed to fracture these wells assumes 15ML/well.
- The volume of fraccing water per year assumes a 25 year lifespan of the field.
- Water footprint is the factor by which the area of land needed to sustainably withdraw 15ML of water for fracturing exceeds the area of land (640,000 m^2) covered by each gas well.

The water footprint figures are much lower than those of other parts of Australia such as the Cooper Basin (139) and Arckaringa Basin (167) but higher than the Sydney Basin (2) and Otway Basin (0.5).[54] As groundwater will in most cases be the sole resource available, alternatives such as the use of recycled water or waterless methods of fracturing are being developed.

During the hydraulic fracturing of the Shenandoah-1A well, the re-use of flowback water as a fracture water source for future wells was investigated. Five of the eight water storage tanks contained flowback water as overflow. It was found that the effectiveness of the friction reducers were not compromised by the use of the flowback water.[55]

Santos currently accesses the Mereenie Aquifer for operational use on site. Water demand for future fracturing will vary for each fracture stimulation but is anticipated to be in the order of 50 m^3 per stimulation. The impact on the aquifer of one-off extraction is expected to be short-term and localized. Water use and the anticipated volume of water will be assessed in order to avoid impacting existing groundwater users.[56]

3.5 The composition of fracture fluids

Fracturing fluid typically consists of 98.5% water and sand, and 0.50% chemical additives. To protect commercial confidentiality, the composition of the additives is not fully disclosed to the public.[57] However, in the United States, the FracFocus Chemical Disclosure Agency provides public access to reported chemicals used for hydraulic fracturing. The chemical data presented on this site has been submitted on a voluntary or regulatory basis by the participating oil and gas companies.[58]

During the drilling of the Shenandoah-1A well in the Beetaloo sub-basin by Falcon Oil and Gas (2011), a basic slickwater was used in the fracturing process to carry the sand proppant and generate fractures. Prior to this, injection by 15% HCl acid was used to reduce the fracture pressure required later. Although gel was on hand to be used, the fracture process in this part of the Northern Territory did not require its use.[59]

PetroFrontier's 2012 drilling program of horizontal well and hydraulic fracturing (Baldwin 2HST1, Owen 3H and MacIntyre 2H) has resulted in a future possibility of using only water as a carrying and fracturing agent with no added chemicals.[60]

3.6 Waste-water disposal

Fracturing fluids are injected into geological formations at high pressure. Once pressure is released, fracture fluid, methane, compounds (including NORM's – naturally occurring radioactive materials) and interstitial water from the deposit flow back to the surface. This waste needs to be properly handled.[61]

In the United States, some issues have been identified but an assessment by the European Union is that these incidents are due to improper handling practices.[62]

In Santos's 2014 drilling plans it has stated that waste storage and transport to licenced disposal facilities will be undertaken in accordance with the relevant legislation and guidelines. Waste generation will be minimised to ALARP. Pits used during drilling activities to store drilling muds will be used to store flowback or waste water also. The structural integrity of the pits will be confirmed prior to being lined with High Density Polyethylene. The flowback fluid will be allowed to evaporate and the remaining sludge will be removed and disposed of. If required, the fluid will be transferred to the Mereenie Central Treatment Plant interceptor pond.[63]

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54 Potential Geological Risks Associated with Shale Gas Production in Australia, Australian Council of Learned Academies (ACOLA), 2013
55 PR2012-0011, Northern Territory Government
56 Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013
57 Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011
58 http://fracfocus.org/
59 PR2012-0011, Northern Territory Government
60 http://www.petrofrontier.com/
61 Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011
62 Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011
63 Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013

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

In conventional drilling it is common practice for single wells at a single site to be used for exploration and production. However, the nature of the reservoirs in which unconventional hydrocarbons are stored, require multiple wells, principally in the development and production stage.

In the United States, a single pad (site) may contain from 2 to 30+ wells to achieve the lowest possible environmental footprint and offer better ways of monitoring wells, in addition to cutting time and expense. If fresh water aquifer contamination is a concern, shallow monitoring wells can be drilled at the perimeters of the pad.[64]

Well pads typically require technical equipment, trucks, chemicals, proppant, water and waste-water containers. This has an impact on the landscape[65] and, can be minimised by grouping well heads together, in clusters, on a single pad.[66]

Horizontal wells are typically used in unconventional exploration and production. Devon Energy in the United States has noted that in the Barnett Shale, a single horizontal well can replace 3–4 vertical wells. These horizontal wells are able to access areas in which the use of vertical wells would be environmentally impossible.[67]

The process of unconventional drilling and hydraulic fracturing can create short-term increases in traffic volume, dust and noise. These impacts are usually limited to the initial 20–30 days of drilling and completion of a well. Various measures are carried out by developers to reduce this impact by e.g. watering unpaved roads to reduce dust, adjustment of the timing of operations and, the installation of sound barriers to reduce noise. When these practices are coupled with the benefits of several horizontal wells from a low number of pads, the environmental impact can be further reduced.[67]

In the Northern Territory, the remoteness of most operations will be an additional factor in reducing any environmental impact.

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[64] King, G.E., Hydraulic Fracturing 101: What every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbour and Engineer should know about Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells, SPE, 2012

[65] Impacts of Shale gas and Shale Oil Extraction on the Environment and on Human Health, EU Directorate-General for Internal Policies, 2011

[66] Unconventional Gas, Resources for the Future, Total, 2012

[67] Modern Shale Gas Development in the United States: a Primer, US Department of Energy et al., 2009

5. Relationships between environmental outcomes of hydraulic fracturing of shale petroleum deposits with geology, hydrogeology and hydrology

Expertise in the field of environmental outcomes on hydrogeology and hydrology lies with other Northern Territory Government departments e.g. the Department of Land Resources Management. However reference is made to this in sections 3.2 (groundwater contamination) and 3.4 (water consumption).

Environmental outcomes of hydraulic fracturing and geology arise from the presence of major and minor faults, the type of host or reservoir rock being fractured and, the propagation of fractures through the rock.

Hydraulic fracturing produces measurable signals but with extremely low magnitude in non-faulted environments. When a fracture engages a typical formation fault, the magnitude is slightly higher. The creation of a moderate magnitude seismic event is regarded as a very remote possibility due to the ease of identifying larger faults on seismic surveys.[64,68]

Hydraulic fracturing also has the potential to generate a pathway for the migration of fluids from nearby geological formations as well as fracture fluid.[69] New monitoring technologies that can shut down operations in this event include pressure sensors in the production casing and the use of acoustic sensors within a microseismic array.

Mechanical properties of shales (a typical unconventional reservoir rock) and in-situ tectonic stress regimes are important factors for well stimulation by hydraulic fracturing. Much of the modelling and actual results of fracturing comes from North America and due to the differences in mechanical properties of shales (organic matter, mineral content) and stress regimes (generally extensional in North America and compressional in Australia), the data may not be directly applicable to the Australian situation.[69] However, even though the fracturing process in some areas of the Northern Territory e.g. the Beetaloo sub-basin is at an early stage, in other areas e.g. the Mereenie area, modelling of fracturing has been taking place since the late 1960's and the fracturing process is tightly constrained (Sections 1.2 and 1.3).

Several studies of fracture propagation have been carried out. In the United States, upward vertical extent of fractures is mostly 90 metres or less,[70] and a 2013 study by Durham University in the UK, indicates that very few stimulated hydraulic fractures propagate more than 350 metres.[70] The CSIRO's research into fracture propagation points to a horizontal orientation to fracture growth in Australian shales although work in this area is ongoing.[69]

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68 Unconventional Gas and Hydraulic Fracturing, Issue Briefing, 2013 – www. BP.com/sustainability
69 Engineering Energy: Unconventional Gas Production, Australian Council of Learned Academies (ACOLA), 2013
70 Davies R.J., et al., Fracking and Aquifers: How Far Up can a Frack Go?, 2013

6. Potential for regional and area variations in the risk of environmental impacts from hydraulic fracturing in the Northern Territory

Several aspects of the geology, environment and social make-up of the Northern Territory may contribute to the potential for regional and area variations in the risk of environmental impacts from fracturing.

In terms of geology, large areas of the prospective McArthur Basin are relatively structurally simple which suggests that the risk of hydraulic fractures intersecting faults is low and therefore contamination of groundwater is low. The laterally extensive and highly competent Antrim Plateau Volcanics in the Beetaloo area blanket the prospective reservoir rocks and therefore act as a frac-barrier to any possible upward propagation of fractures. In a similar fashion, the Stokes Siltstone is acting as a regional top seal across the Mereenie field.

The regional variations in the size of the separation zones between fracture targets and aquifers in the Northern Territory may introduce a regional variation in the risk of environmental impacts. Section 3.2 notes that the vertical separation distance between the Tindall Limestone Aquifer and the Lower Kyalla fracture target in the Beetaloo area is over 1300 metres. Santos states in its 2014 drilling/environmental plan that the Mereenie aquifer is separated from the target formations by over 500 metres. Santos has modelled maximum fracture propagation for Mereenie to be in the order of 70 metres (see also sections 1.2 and 1.3). Given the separation and modelling scenario, fracture propagation into the aquifer is considered unlikely to occur.[71] Durham University's 2013 study on upward fracture propagation proposes that regulators should consider setting a distance limit of at least 600 metres between aquifers and fracture targets, especially in new areas where fracture data is incomplete or absent.[70] Current exploration activity includes undertaking rock property and composition analysis of rock from drill core to assess the fracturability of potential reservoir rocks thereby adding to the fracture dataset.

Water use in hydraulic fracturing in the Top End compared to arid regions is certain to result in a regional variation in the risk of environmental impacts. Most of the potential shale gas basins in Australia are located either wholly or partly within arid regions. This means that groundwater will likely be the sole water resource available to energy companies. Santos currently access the Mereenie aquifer water for operational use on site at the Mereenie field. Water demand for fracturing will vary per fracture stimulation, but is anticipated to be in the order of approximately 50m^3 per fracture stimulation. The impact on the aquifer of once-off extraction for fracturing is expected to be relatively short term and localised. Water use and the anticipated volumes of water will be assessed in order to ensure that their use does not adversely impact existing groundwater users.[71] Ongoing research into the use of non-potable water and e.g. nitrogen as a fracture fluid is taking place.

The differences in climate in the Top End of the Northern Territory compared with the arid centre could potentially result in a regional variation of risk. For example open pit storage for waste water in the dry season in the Top End will pose little risk of overflow into soil and surface water sources. However the wet season poses more risk and operators must demonstrate how this will be managed especially during development and production operations when activities are not confined to the dry season as with exploration activities. Permanent pipelines have been constructed in some areas to transfer waste-water to disposal facilities e.g. in the Barnett Shale around Dallas-Fort Worth International Airport.[67]

Environmental impacts will differ in populated areas compared with the outback especially in terms of noise, dust and landscape. Much of this is unavoidable but can be minimised (section 5 and 7).

[71] Environment Plan Summary Mereenie Field Development 2014, Fracture Stimulation, Completion, Workover and Recompletion, Santos, 2013

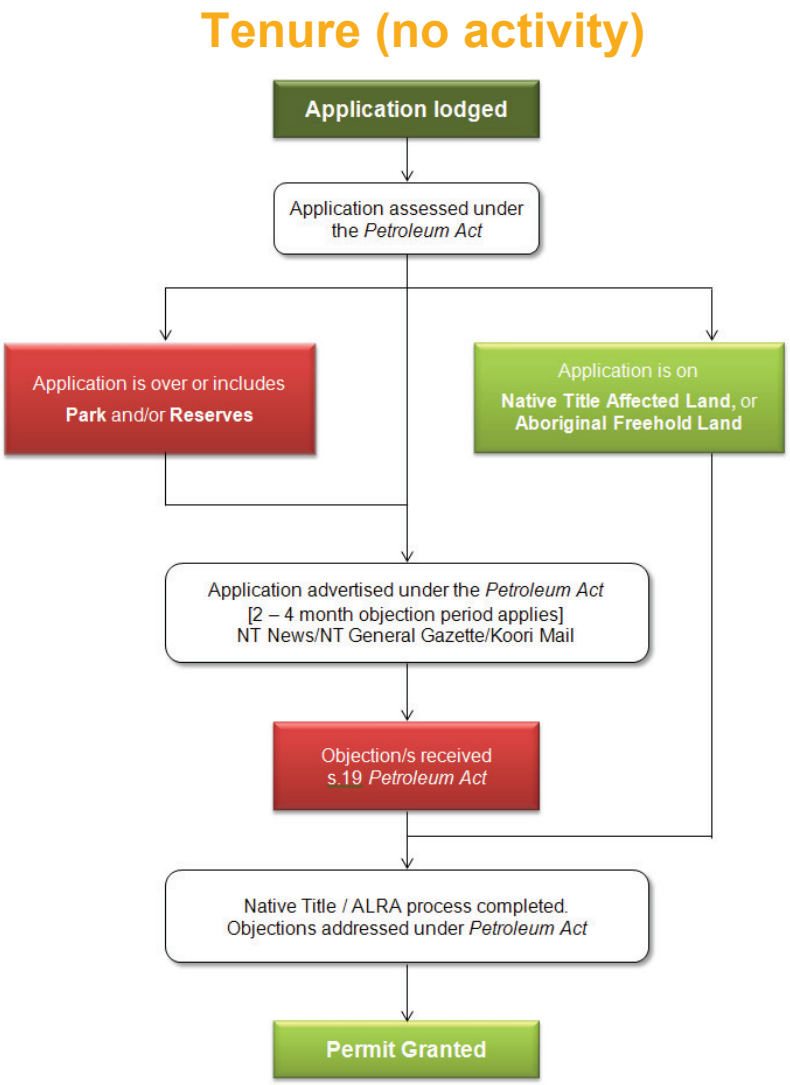
7. Effective methods for mitigating potential environment impacts before, during and after hydraulic fracturing.

7.1 Regulatory Overview

A comprehensive description of the legislative and regulatory processes under the *Northern Territory Petroleum Act 2011* (the Act) that govern petroleum activities – including hydraulic fracturing – in the Northern Territory is provided in the Appendix. The following section provides a brief overview of those processes, together with flow-chart representations.

The first stage of commencement of petroleum activities is the granting of tenure as illustrated in Figure 1 below, and elaborated upon in the Appendix.[72] Applicants must satisfy a range of criteria in order to secure the grant of tenure including technical and financial capacity to undertake the proposed activities.

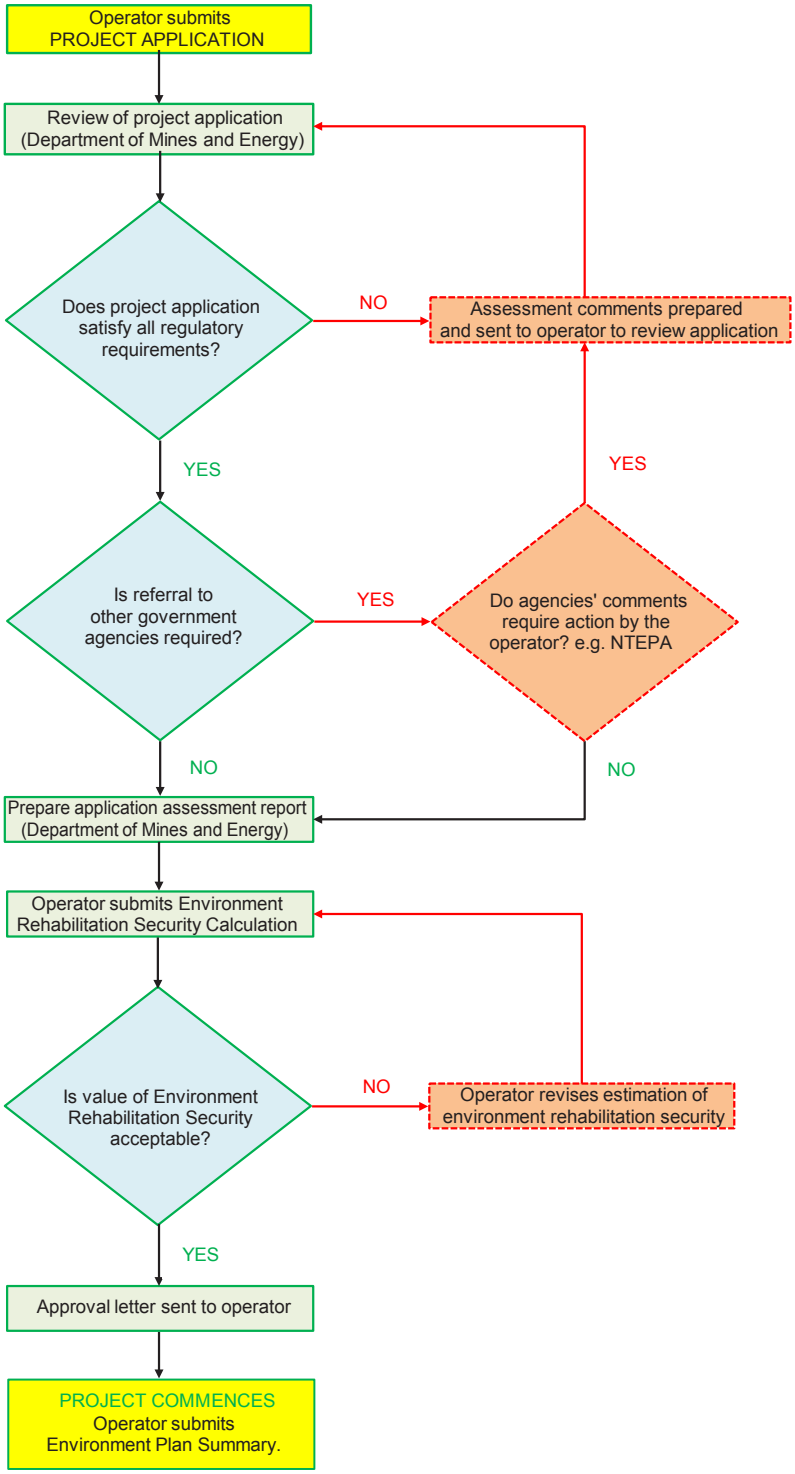
Figure 1.



A grant of tenure provides access to land, but before ground disturbing activities commence on that land a Petroleum Project Approval must be sought in accordance with the Act and The Schedule of Onshore Petroleum Exploration and Production Requirements 2012[73] (the Schedule). The process is represented in Figure 2 below. It should be noted that even where approval has been given for a Project Plan, Operational Applications may still need to be lodged to carry out particular activities within the Project.

72 Appendix, p.1 and Attachment D, p.2
73 Attachment D

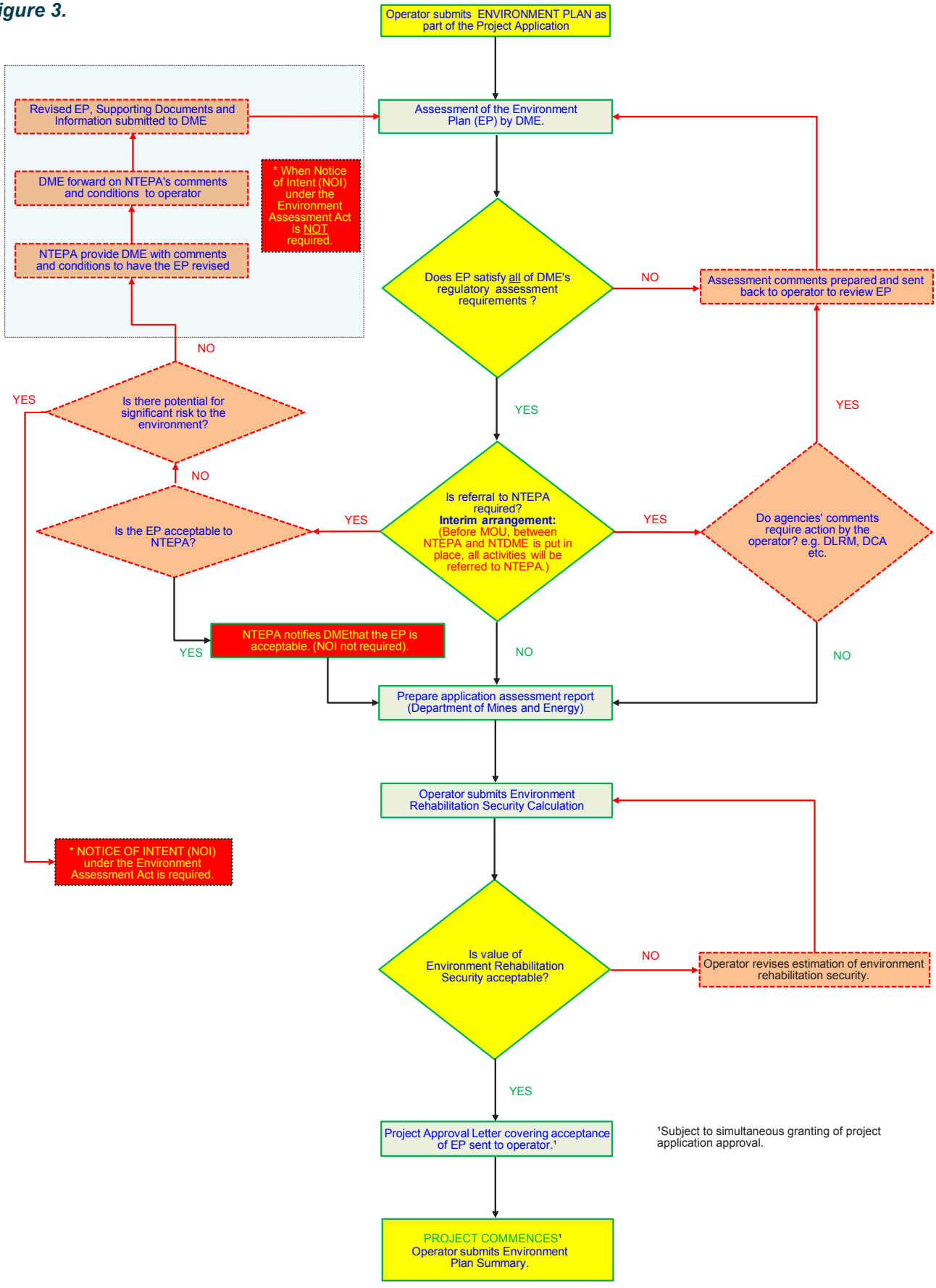
Figure 2.



As part of the Petroleum Project Approval Process, the applicant must lodge an Environment Plan (EP). In assessing the EP, DME provides it to the Northern Territory Environmental Protection Agency (EPA) for comment and consideration. DME may also determine that the EP needs to be provided to other relevant government agencies (particularly DRLM and Parks and Wildlife) for comment. DME applies rigour and scrutiny to EP's that it approves before hydraulic fracturing or other petroleum activities can occur. An inadequate EP will not be accepted.

The assessment process is represented in Figure 3, noting that there are a number of feedback loops and that the EPA has the capacity to provide comments that need to be addressed by the applicant, or can advise that a "Notice of Intent" is required under the *Environment Assessment Act.*

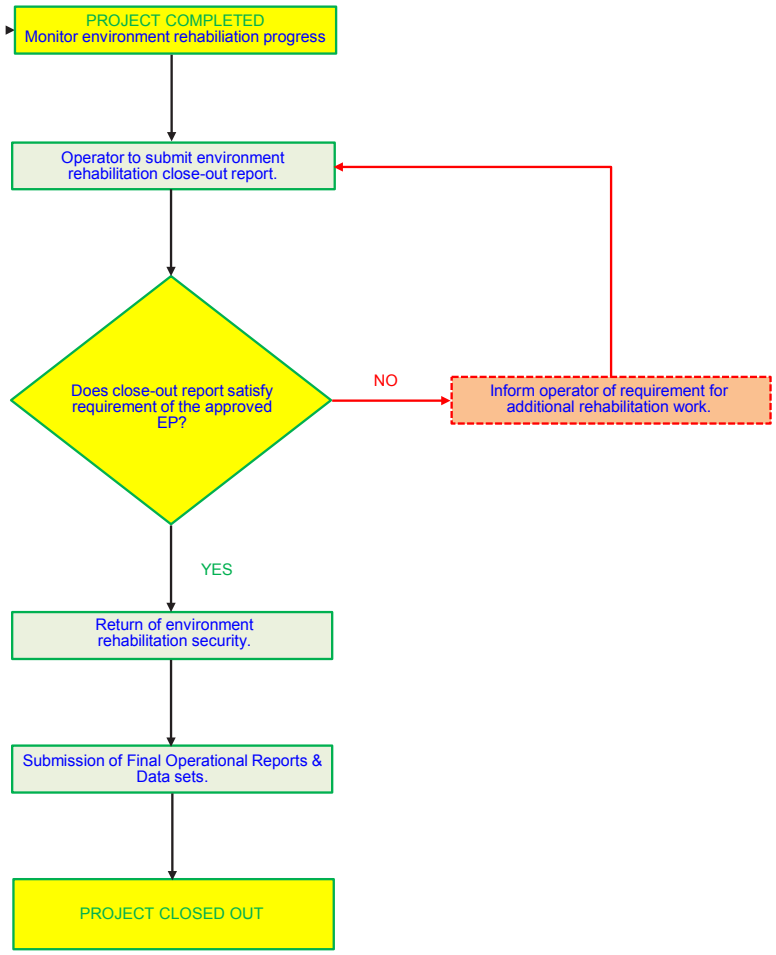
Figure 3.


Operator submits ENVIRONMENT PLAN as part of the Project Application
Assessment of the Environment Plan (EP) by DME.
Revised EP, Supporting Documents and Information submitted to DME
DME forward on NTEPA's comments and conditions to operator
NTEPA provide DME with comments and conditions to have the EP revised
* When Notice of Intent (NOI) under the Environment Assessment Act is NOT required.
Does EP satisfy all of DME's regulatory assessment requirements ?
NO
Assessment comments prepared and sent back to operator to review EP
YES
YES
NO
Is there potential for significant risk to the environment?
YES
NO
Is the EP acceptable to NTEPA?
YES
Is referral to NTEPA required?
Interim arrangement:
(Before MOU, between NTEPA and NTDME is put in place, all activities will be referred to NTEPA.)
YES
Do agencies' comments require action by the operator? e.g. DLRM, DCA etc.
YES
NO
NTEPA notifies DMEthat the EP is acceptable. (NOI not required).
NO
Prepare application assessment report (Department of Mines and Energy)
Operator submits Environment Rehabilitation Security Calculation
* NOTICE OF INTENT (NOI) under the Environment Assessment Act is required.
Is value of Environment Rehabilitation Security acceptable?
NO
Operator revises estimation of environment rehabilitation security.
YES
Project Approval Letter covering acceptance of EP sent to operator.[1]
PROJECT COMMENCES[1]
Operator submits Environment Plan Summary.
[1]Subject to simultaneous granting of project application approval.

During the life of the project, compliance measures in place include mandatory self-reporting, inspections and audits as described in the Appendix.[74]

At the completion of the project the operator must submit a "Close-Out" report to DME that satisfies the requirements of the EP – including the full environment rehabilitation works. The closure process is illustrated in Figure 4 below, and described in detail in the Appendix.[75]

Figure 4.



7.2 The selection of sites of wells

The granting of a permit or licence over a particular parcel of land is subject to the provisions of the Act.[76] Once 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)[77] – which is referred to the EPA for comment – as well as a Rehabilitation Plan.[78]

DME grants approval for an operator to carry out a specific activity in accordance with the approved work program – during the course of an activity, no variation of the selection of well sites is permitted without another approval process. Self-reporting, audits and inspections provide the compliance framework.[79]

7.3 Well design, construction, standards, control of operational safety and well integrity ratings

The Schedule addresses the well design, construction, standards, control and operational safety and well integrity ratings in Part V, Division 1, Clauses 501 to 532.[80]

As part of its formal assessment process, DME requires particular operational documents to be submitted including the work program which must include details relating specifically to well design, construction,

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74 Appendix, p.32
75 Appendix, p.33
76 Appendix, p.27
77 Appendix, p.28
78 Appendix, p.33
79 Appendix, p.32
80 Appendix, p.28 and Attachment C, p.59

standards, control of operational safety and well integrity ratings.[81]

Internal DME checklists ensure that the operator has addressed the following critical, operational and well safety issues:

- All activities and material to meet or exceed API standards
- Blow out preventer (BOP) Systems and Blow-out Prevention drills
- Methods of mandatory reporting
- Well control requirements
- Cementing of all casing strings to surface
- Mandatory water quality testing; before during and after the activity
- Safe separation between shallow aquifers and the hydrocarbon target zone (section to be fractured)
- Submission of fracture modelling confirming maximum fracture height and length, hence confirming safe separation
- Chemicals list for public disclosure on DME's website
- Mandatory validation of casing and cement using Cement Bond Logs
- Mandatory validation of all barriers by pressure testing
- Mandatory Formation Integrity Testing
- Evidence of adequate insurance
- Payment of adequate Rehabilitation Environment Security
- Evidence of Cultural Clearances
- Evidence of comprehensive stakeholder consultation
- Submission of Environment Plan (EP) summary for public disclosure on DME's website
- Pressure safety trip-out systems utilised during fracture stimulation activities that prevent allowable pressure limits of surface pipework and down-hole casing being exceeded
- Pressure monitoring provides confirmation that well integrity has not been impacted by fracture stimulation activities
- Installation of a Completion Tubing string

DME grants approval for the operator to carry out its activity in accordance with its approved work program, which includes all supporting documents. No variation is permitted, and self-reporting, audits and inspections provide the compliance framework.[82]

In accordance with Clause 110 of the Schedule, DME or third party Inspectors have the ability to carry out operational and environmental audits. Compliance monitoring is carried out to ensure that activities take place in accordance with the approved work program and EP. Desk top auditing requires the assessor to respond to specific well integrity and barrier validation triggers which will ultimately confirm that the well was constructed to levels exceeding American Petroleum Institute (API) standards.

All well suspensions, completions and abandonments must take place in accordance with Clauses 528, 529 and 530 of the Schedule.[83]

7.4 Water use

The current regulatory framework does not explicitly address water use, however it is intended that this will be included in the new Environment and Resource Management Regulations that are currently being developed by DME.

Under the Schedule[84], as part of its application, an operator must submit a statement of proposed environmental protection and rehabilitation measures. To satisfy this requirement, the operator's EP must include details relating to water use.

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81 Appendix, p.28
82 Appendix, p.32
83 Appendix, p.33 and Attachment C, p.59
84 Clause 501 (2) (o), Attachment C, p.59

Also, Clause 525 of the Schedule provides for the protection of aquifers.[85]

The DME Checklist: "Onshore Environmental Plan"[86], ensures that the operator is required to address the following water use issues:

- Anticipated consumption
- Source
- Groundwater salinities
- Whether independent groundwater monitoring will be taking place
- Frequency of testing before, during and after
- All reasonably foreseeable risks

No variations to the EP and other plans are permitted without re-approval, and compliance is managed through site visits and self-reporting.[87]

7.5 Chemical use

The Schedule currently has no explicit reference to chemical use – Clause 515 of the Schedule covers well control properties of drilling fluid only. However, the DME Checklist: "Onshore Environmental Plan" provides that an operator must address the following issues in relation to chemical use:

- Types of chemicals
- Submission of all Material Safety Data Sheets for public disclosure
- All reasonably foreseeable risk

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.

7.6 Disposal and treatment of waste water and drilling muds

To obtain project approval, the operator's EP must include details relating to the disposal and treatment of waste water and drilling muds, and specific reference is also made to this in the DME Checklist: "Onshore Environmental Plan".

The checklist requires that the operator must address the following:

- Anticipated waste type and volumes
- Methods of disposal
- End delivery points of all produced fluids and waste products
- Waste Management Plan in place
- All reasonably foreseeable risks

Site visits and assessment of the completion of the rehabilitation plan provide the compliance framework.

7.7 Fugitive emissions

Fugitive emissions that might occur before or after a petroleum exploration activity such as fracture stimulation are negligible. Fugitive emissions can be naturally occurring and so DME takes no account of emissions that occur before or after hydraulic fracturing – on the basis that the well has been suspended or abandoned in accordance with the DME approval. DME only has a role in regulating fugitive emissions that might take place during exploration or production activities.

For both exploration and production activities fugitive emissions need to be addressed as part of the project approval in the operator's EP.[88]

In particular, Clauses 526, 527, 531 and 540 of the Schedule require that exploration operators undertake drill stem tests and the associated disposal of flammable vapours, and Clause 619 requires that in production gas will not be flared or vented without approval.

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85 Attachment C, p.65
86 Attachment D, p.109
87 Appendix, p.31
88 Appendix, p.29

7.8 Noise

All petroleum operations in the NT take place in remote rural locations. Further, the levels of noise are not considered to be any more than typical urban construction sites or normal city traffic. Nevertheless, details relating to noise must be included in the operator's EP, and to ensure its inclusion it is referred to in DME's Checklist: "Onshore Environmental Plan".

7.9 Monitoring requirements

In the EP the operator must address its responsibilities for monitoring as part of its Implementation Strategy.[89] During the drilling of wells, Clauses 510 and 511[90] of the Schedule require that the appropriate monitoring system is installed and operational during the drilling of wells. For production wells, Clauses 601 to 635 stipulate the levels of monitoring and safety systems required. To ensure full well integrity so that well fluids are contained without escaping, operators are required to monitor well pressures to detect any change of pressure.

During fracturing activities, operators are required to constantly monitor surface and down-hole pressures. Pressure monitoring provides confirmation that well integrity has not been impacted by fracture stimulation activities. Safety trip-out systems utilised during fracture stimulation activities prevents pressures from exceeding the pressure rating of surface pipework and down-hole casing.

Microseismic monitoring is a technique using earthquake seismology methods to determine details about the level of fracturing and deformation associated with the fracture stimulation activity. The current regulatory framework does not recognise microseismic monitoring, however this will be addressed during the development of new Environment and Resource Management regulations.

As part of the project approval process, the operator's EP must include details of water monitoring to be undertaken and this includes:

- Disclosure of salinities for all aquifers previously drilled through
- Baseline water monitoring to commence during drilling
- Water monitoring to continue during and after fracture stimulation activities
- The submission of a final monitoring report which can then be referred to the EPA and the Department of Land Resource Management (DLRM)

7.10 The use of single or multiple well pads

The current NT legislation does not recognise the use of single or multiple well pads – however, this will be addressed during the current new draft regulations to replace the Schedule.

At this point in time, given the relative low level of exploration and associated discoveries in the NT, activities have included only one well and so have been confined to the use of a single well pad. If future development should warrant it, DME would support these pads being converted to servicing multiple wells, because of the reduced environmental footprint associated with multiple well pad use.

7.11 Rehabilitation and closure of wells (exploratory and production) including issues associated with corrosion and long term post closure

Rehabilitation and closure of wells has been dealt with previously in 7.3. In relation to the specific issue of corrosion and long term post closure, this is addressed by Clause 529 (9) of the Schedule which provides that: "Any intervals of cased hole between cement plugs shall be filled with fluid that is of an appropriate density and suitably inhibited to prevent corrosion of the casing."

7.12 Site rehabilitation for areas where hydraulic fracturing activities have occurred

Rehabilitation issues have been covered in earlier parts of this Section, and further detail on rehabilitation issues is available in the Appendix. That said, of fundamental importance is that the Rehabilitation Security paid by the operator at the beginning of a project is not returned unless and until rehabilitation has been completed in full in line with the approved Rehabilitation Plan.

89 Appendix, p.28
90 Attachment C, p.62

Appendix – Regulation of petroleum activities in the NT

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1. Tenure

The *Northern Territory Petroleum Act 2011* (the Act)[1] is the principal legislation dealing with petroleum tenure, exploration and production activities, onshore and within inland waters of the Territory, together with The Schedule of Onshore Petroleum Exploration and Production Requirements 2012 (the Schedule).[2]

Section 3 provides the following Objective for the Act:

> **3. Objective**
>
> (1) The objective of this Act is to provide a legal framework within which persons are encouraged to undertake effective exploration for petroleum and to develop petroleum production so that the optimum value of the resource is returned to the Territory.
>
> (2) The legal framework provides for the following:
>
> (a) the granting of petroleum interests to persons for exploration, production and ancillary activities associated with exploiting petroleum, and the renewal or transfer of those interests;
>
> (b) clear statements about the role of government following the grant of petroleum interests;
>
> (c) the promotion of active exploration for petroleum, and of the development of petroleum production if commercially viable, by persons granted petroleum interests;
>
> (d) the assessment of proposed technical works programmes for the exploration, appraisal, recovery or production of petroleum and of the financial capacity of persons proposing to carry out those programmes;
>
> (f) the reduction of risks, so far as is reasonable and practicable, of harm to the environment during activities associated with exploration for or production of petroleum;
>
> (g) the collection of information about petroleum exploration and production and the dissemination of that information;
>
> (h) the efficient administration of this Act and collection of royalties;
>
> (i) other matters in connection with exploration for and production of petroleum.

Tenure is provided either through the grant of an Exploration Permit (permit) or a Production Licence (licence) – noting that the holder of a permit or licence may, in some circumstances, apply for and be granted a Retention Licence.[3]

In accordance with Sections 11-15 of the Act,[4] tenure can be granted to any land within the Territory, subject to special provisions relating to Aboriginal land, and certain parks and reserves.

Oil and gas operators (operators) are granted exploration permits and production licences over a parcel of land to explore using various methods, and responsibly exploit and produce hydrocarbons. The NT Department of Mines and Energy (DME) provides Guidelines on the Criteria for Assessment of Petroleum Exploration Permit Applications and a copy of these are at Attachment D.[5]

If an operator's application meets all requirements tenure is approved – however, having secured tenure, before any disturbance on the defined land can occur, project and operational approvals need to be granted.

Divisions 2, 3 and 4 of the Act[6] provide further detail on the administration of permits and licences.

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1 www.nt.gov.au/d/minerals
2 www.nt.gov.au/d/minerals
3 Operators can hold the following forms of tenure: i) Exploration permit; ii) Retention Licence (under condition that a petroleum discovery has been made but the resource is not currently considered to be commercial; iii) Production Licence.
Petroleum activities that are categorised as Project Applications are granted under the relevant parts of Schedule in Part V, Division 1.
4 Sections 11-15 of the Act, Attachment B, p.37
5 Guideline: Criteria for Assessment of Petroleum Exploration Permit Applications, Attachment D p.94
6 Attachment B p.40

2. Petroleum project approval process

Under The Schedule, the operator must submit an application to carry out petroleum activities within the granted tenure[7]. Before granting approval for specific activities, DME routinely refers all activities to the NT Environmental Protection Agency (EPA) for comment. At the same time, the operator needs to determine whether a self-referral to the Commonwealth Government for assessment under the *Environment Protection and Biodiversity Conservation Act* is required.

DME provides Guidelines for Applications for Drilling or Workover Rig Activities and a copy of these are provided in Attachment D.[8] As part of the assessment, the operator must submit an Environmental Plan (EP) and a copy of Guidelines for Environmental Plan Requirements is included in Attachment D[9].

The formal DME approval process by DME's Petroleum Operations Team includes assessing the EP in accordance with the Checklist: "Onshore Environmental Plan" a copy of which is at Attachment D[10].

The integrity of wells is a particular focus of DME's assessment and Part V, Division 1, Clauses 501 to 532 of the Schedule address the well design, construction, standards, control and operational safety and well integrity ratings – a full extract is at Attachment C[11].

Also, Clause 537 of the Schedule states:

> **Special Services**
>
> (1) Special services include logging, perforating, testing, cementing or portable laboratory services, power-tong services, wireline services, coiled tubing operations, acidizing, fracturing, artificial lift or similar services carried out at a well location.
>
> (2) The installation and operation of well pumping units, and the operation of wireline and coiled tubing services, acidizing, fracturing, cementing, hot oil operations and other special services shall be carried out in accordance with these directions and the applicable recommended practices set forth in A.P.I. Recommended Practice 54, (RP 54) "Oil and Gas Well Drilling and Servicing Operations".

As part of its formal assessment process, and prior to granting approval, DME requires particular operational documents to be submitted. These documents include the work program and several management plans. To obtain approval, the work program must include details relating specifically to well designs, standards, control and operational safety and well integrity ratings.

As part of this process the mandatory documents include:

- Particular work program
- Environment Management Plan
- Emergency Response Plan
- Oil Spill Contingency Plan
- Safety Management Plan

To ensure inclusion in the operator's approved work programs, specific reference is made to the above in DME's Onshore Drilling and Workover & Stimulation Programs Assessment Checklists which are available in Attachment D.[12]

The above checklists also ensure that the operator has addressed the following critical, operational and well safety issues:

- All activities and material to meet or exceed API standards
- BOP Systems and Blow-out Prevention drills
- Methods of mandatory reporting
- Well control requirements
- Cementing of all casing strings to surface

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7 Attachment B, p.38
8 Attachment D, p.99
9 Attachment D, p.103
10 Attachment D, p.109
11 Attachment C, p.57
12 Attachment D, p.125 & p.133

- Mandatory water quality testing; before during and after the activity
- Safe separation, about 1 km, between shallow aquifers and the hydrocarbon target zone (section to be fractured)
- Submission of fracture modelling confirming maximum fracture height and length, hence confirming safe separation
- Chemicals list for public disclosure on DME's website
- Mandatory validation of casing and cement using Cement Bond Logs
- Mandatory validation of all barriers by pressure testing
- Mandatory Formation Integrity Testing
- Evidence of adequate insurance
- Payment of adequate Rehabilitation Environment Security
- Evidence of Cultural Clearances
- Evidence of comprehensive stakeholder consultation
- Submission of Environment Plan (EP) summary for public disclosure on DME's website
- Pressure safety trip-out systems utilised during fracture stimulation activities that prevent allowable pressure limits of surface pipework and down-hole casing being exceeded
- Pressure monitoring provides confirmation that well integrity has not been impacted by fracture stimulation activities
- Installation of a Completion Tubing string

Concurrently with DME's assessment, the EP is referred to the EPA for comment and consideration – all EPA comments must be addressed by the operator as a condition of activity approval. It is also possible that the EPA may determine that there is sufficient environmental risk to require the lodging of a "Notice of Intent" under the *Environment Assessment Act* thereby triggering a formal environmental impact assessment process.

The Schedule includes Clauses specifically in relation to the protection of the environment and aquifers:

> **109. Protection of Environment**
>
> (1) An Operator shall ensure that operations are carried out in a manner that avoids or, where that is not practicable, minimizes any adverse impact on the environment.
>
> (2) The holder of a title shall ensure that all his employees and contractors comply with an approved Code of Environmental Practice, or with the APEA Code of Environmental Practice.
>
> **525. Protection of Aquifers**
>
> All reasonable steps shall be taken during well or production operations to prevent communication between, leakage from or the pollution of aquifers that serve, or could serve, any useful purpose.

These issues need to be addressed through the EP lodged as part of the project approval process, which is then assessed against the DME Checklist: "Onshore Environmental Plan" – noting also that the EP is referred to the EPA.

Fugitive emissions may also be an area that needs to be dealt with under the EP, noting also that Clauses 526, 527, 531 and 540[13] of the Schedule provide requirements to deal with fugitive emissions. Further, for production activities, Clause 619 of the Schedule[14] requires that gas will not be flared or vented without approval, and this needs to be addressed in the operator's Reservoir Management Plan which is required by Clause 606 of the Schedule as follows:

[13] Full extracts available at Attachment C, p.57
[14] Attachment C, p.70

606. Reservoir Management Plan

(1) Subject to Sub-Clause (2) and Clause 607, a completion shall not be brought into production except in accordance with a reservoir management plan approved by the Director as consistent with maximum practical recovery of petroleum from the reservoir.

(2) Where, on the commencement of these requirements, a reservoir is already in production, a reservoir management plan for that reservoir shall be submitted for approval within one year after the commencement of these requirements.

(3) The Director may require that a reservoir management plan be revised from time to time.

An important point to note is that as part of DME's Checklist for the approval of Environment Plans, responsibilities are placed upon operators for the establishment of appropriate monitoring systems as part of their implementation strategy.

As appropriate, DME may also determine that the application needs to be referred to other relevant government agencies for the provision of comments.

The operator gains approval to carry out the activity in accordance with all materials and details submitted in relation to its work program – therefore, any change to its approved programs, including its EP, must be disclosed to DME for reassessment.

Where project approval is granted to an operator, an Environment Plan Summary must be lodged for full public disclosure on DME's website.[15]

[15] http://www.nt.gov.au/d/Minerals_Energy/index.cfm?newscat1=&newscat2=&header=Environmental%20Management%20Plan%20Summaries

3. Operational approvals

Even where a Project Approval has been given, Operational Approvals are required to carry out a particular activity within a project which has already commenced – that is, an activity where Project Approval has already been granted. Operational activities are ones leading to a specific change to the wellbore geometry and so for this reason, are activities that go outside the already approved work program.

Examples of well activities requiring an application for approval:

- Any activity that goes outside the already approved work program
- Side tracking a well
- Suspension
- Abandonment
- Flow testing
- Stimulating
- Well Completion

The Guidelines for Applications for Drilling or Workover Rig Activities outline the process for Operational Approvals which is normally as an addendum or amendment to the Project Plan.

It is important to note that DME's letter of Project Approval to an operator explicitly includes the following:

Clause 501 (5) of the NT Schedule of Onshore Petroleum Exploration and Production Requirements 2012 states: "An approved program shall not be varied without approval".

An example of DME's approval letter for a stimulation fracturing activity is provided in Attachment D.[16]

[16] Attachment D, p.176

4. Compliance and monitoring

In accordance with its formal process, DME grants approval for the operator to carry out its activities in accordance with its approved work program (for whatever the activity may be), its approved Environment Plan and all other supporting documents that are required to be submitted. In accordance with its approved Work Program and Division 4 of The Schedule[17], the operator is legally obliged to report a range of incidents to DME – these include injuries and death; property damage; hazardous events; and emergencies. To ensure inclusion in the operator's approved work programs, specific reference is made to the above reporting responsibilities in DME's Onshore Drilling and Workover & Stimulation Programs Assessment Checklists which are available in Attachment D.[18] Emergency contacts for DME Officers, including 24 hour contact numbers are provided to operators. Failure to report in accordance to the above requirements can result in significant penalties.

Further, as an overlay to self-reporting requirements, under Clause 110 of the Schedule the powers of an Inspector (meaning *a person appointed an Inspector under the Act*) are specified:

110. Inspectors

(1) Where an Inspector considers -

(a) that any plant is in an unsafe condition; or that the integrity of any operating system has been, or is in danger of being, compromised; or

(b) that work being carried out

(i) is contravening a provision of the Act, these directions, or any additional conditions imposed by the Director;

(ii) is unsafe; or is compromising, or may compromise, the integrity of an operating system; or

(iii) is not in accordance with good oilfield practice, the Inspector may, by a notice in writing, refer the matter to the relevant Operator.

(2) The notice shall specify a day by which the Operator shall report to an Inspector on the action taken in relation to the notice.

(3) An Inspector may -

(a) direct that no further work be carried out until the matter referred to in the notice is remedied, or until an Inspector otherwise approves the resumption of work;

(b) give directions as to the measures to be taken to remedy the matter referred to in the notice, which directions may include -

(i) that plant be repaired or replaced;

(ii) that any part of the environment be restored or rehabilitated;

(iii) that a particular work practice be altered or discontinued.

(4) An Operator shall not contravene, or fail to comply with, a notice given under this requirement.

In accordance with Schedule 110, DME or third party inspectors have the ability to carry out operational and environmental audits. Checklists for site visits cover Drilling Operations, Environment, Fraccing Completion and Testing Operations and Well Testing Operations.[19]

Compliance Monitoring is carried out to ensure that activities take place in accordance with the approved work program and EP. Although neither The Act nor the Schedule enforces Compliance Monitoring of petroleum activities, DME's Petroleum Operations Team conducts daily desktop audits of operator's activities.

The desktop audit activity was developed by the Petroleum Operations Team after the Montara Inquiry. The process requires the assessor to respond to specific well integrity and barrier validation triggers which will ultimately confirm that the well was constructed to levels exceeding API standards.

[17] Attachment C, p.71
[18] Attachment D, p.125 and p.133
[19] Site visit checklists at Attachment D, p.109, 125, 133, 139

5. Rehabilitation and close-out

As part of the project approval process, the operator must include a Rehabilitation Strategy that forms part of its approved EP. This forms the basis for calculating a Rehabilitation Security that must be paid by the operator to DME as a mandatory step in project approval. At the conclusion of a project, the operator must demonstrate that rehabilitation of the site has been carried out in accordance with its Rehabilitation Strategy in order to be eligible to receive the Rehabilitation Security.

Clause 532 on the Schedule provides the requirements that must be satisfied for exploration activities:

> **532. Restoration of Site**
>
> As far as possible a well site area shall be restored to its former condition and if any part of a wellhead is left above ground level, the well shall be adequately fenced. Mousehole and rathole shall be plugged at surface.

And Clauses 626, 627 and 628 of the Schedule provide the requirements for production activities:

> **626. Plugging of Wells**
>
> (1) Unless otherwise approved, on completion of production activities and prior to the surrender of a production licence all wells shall be plugged and abandoned.
>
> (2) The Director may require that a well be plugged and abandoned -
>
> (a) in the interest of safety;
>
> (b) for the protection of the environment; or
>
> (c) for the purpose of the elimination of waste or contamination.
>
> **627. Removal of Facilities**
>
> (1) Upon completion of production activities and within 2 years after the surrender of a production licence, every production facility shall be dismantled and removed or abandoned in a reasonable manner acceptable to the Director.
>
> (2) Production facilities may remain intact in a licence area following 2 years after the surrender of the production licence only with approval.
>
> (3) The Director may require that any part or all of a production facility be dismantled and removed or abandoned within a reasonable time-frame –
>
> (a) in the interest of safety;
>
> (b) for the protection of the environment; or NT Onshore Petroleum Directions Page 68 16/01/2013
>
> (c) for the purpose of the elimination of waste or contamination.
>
> **628. Restoration of Lands**
>
> Following the completion of production activities and within 2 years after the surrender of a production licence, the land surrounding or affected by production facilities and wells shall be restored as far as practicable to its original condition to the reasonable satisfaction of the Director.

DME provides a Guideline for Environment Rehabilitation Reporting[20], and it also has a checklist for operational and environmental audits[21] that can be used to ensure full compliance with rehabilitation requirements.

Further, all well suspensions, completions and abandonments must be undertaken in accordance with Clauses 528, 529 and 530 of the Schedule, and Clause 536 of the Schedule requires that an operator submit a Well Completion Report within six months of rig release.

[20] Attachment D, p.169
[21] Attachment D, p.139

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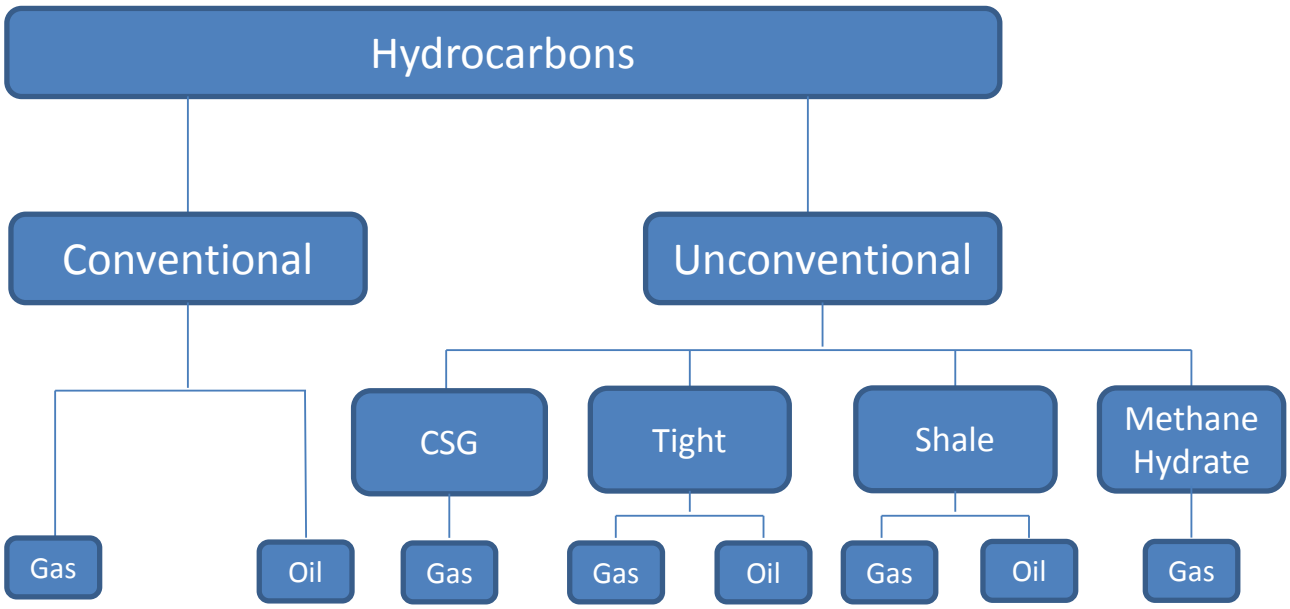
Attachment A – Petroleum (hydrocarbon) product definitions



1. Unconventional and conventional resources differ not by chemical composition but by the geological characteristics of the reservoir and the techniques needed to extract the oil/gas.

2. All of the above are hydrocarbons

Definitions

- **Conventional oil and gas** – have the same composition as unconventional oil and gas but are extracted using the natural high reservoir pressure found at depth – the reservoir rocks are usually porous and permeable – occasionally, hydraulic fracturing may be used to enhance production (extraction of oil/gas)
- **Reservoir** – the body of rock holding the oil/gas/water
- **Porosity** – the space (pores) between the grains that make up the reservoir rock, usually occupied by water, gas and/or oil
- **Permeability** – a measure of the level of interconnectivity between the pores and is an indication of the ease encountered in extracting the oil/gas/water
- **Shale oil** – oil trapped in highly impermeable shale rock - can be hydraulically fractured to release oil
- **Shale gas** – gas trapped in highly impermeable shale rock - can be hydraulically fractured to release gas
- **Tight oil** – oil trapped in highly impermeable rock, usually sandstone - can be hydraulically fractured to release oil
- **Tight gas** – gas trapped in highly impermeable rock, usually sandstone - can be hydraulically fractured to release gas
- **CSG (Coal seam gas)** – methane gas adsorbed onto the surface of coal - the extraction method to the above is different i.e. the coal needs to be dewatered which, lowers the pressure to induce gas flow; hydraulic fracturing is not necessary. Also referred to as coal bed methane or CBM.
- ****Methane hydrates** – methane trapped with in the chemical structure of water forming a structure similar to ice – technology to extract is under development
- ****Oil shales** – different from shale oil and are fine grained shales containing kerogen (solid organic compound) – can be mined near surface

**not relevant to this submission but noted here for clarity and distinction from other similar unconventional resources

Attachment B – Extracts from the *NT Petroleum Act (2011)*

Sections 11–15 – Grant of Tenure

11. Land subject of exploration permit or licence

Subject to this Act, an exploration permit or licence may be granted in relation to any land within the Territory.

12. Grant of mining interest

Subject to this Act and the Land Rights Act, a corporation or a person who has attained the age of 15 years, may apply for and be granted an exploration permit or licence, being a mining interest as defined in the Land Rights Act, in relation to Aboriginal land.

13. No negotiations without Minister's consent

(1) A person must not enter into negotiations with a Land Council for the consent of the Council to the grant of an exploration permit over Aboriginal land without the Minister's consent.

(2) The Minister's consent to negotiations may only be given to a person who has lodged an application for an exploration permit over Aboriginal land with the Minister.

(3) When the Minister receives an application for an exploration permit over Aboriginal land, the Minister must give written notice to the relevant Land Council that the application has been received.

(4) The Minister may give or refuse consent to negotiations between the applicant and the relevant Land Council for the Council's consent to the grant of the exploration permit to the applicant.

(5) However, if the Minister has previously consented to negotiations between another applicant and the Land Council for the Council's consent to the grant of an exploration permit over the same land, the Minister must not give a further consent until the antecedent negotiations are concluded.

(6) The Minister's consent to negotiations may be given conditionally or unconditionally.

(7) Although the Minister has consented to negotiations between an applicant and a Land Council, the Minister may exercise either or both the following powers:

(a) the Minister may withdraw the consent at any time before the negotiations are concluded;

(b) the Minister may refuse the application for an exploration permit (in which case the consent, if not explicitly withdrawn, is taken to be withdrawn).

(8) If the Minister refuses or withdraws consent to negotiations between an applicant and a Land Council (without contemporaneously refusing the application for an exploration permit):

(a) the refusal or withdrawal of consent is not to be taken to be a refusal of the application for an exploration permit; and

(b) the Minister may later give (or again give) consent.

(9) In this section:

ALRA means the *Aboriginal Land Rights (Northern Territory) Act 1976* (Cth).

concluded – negotiations with a Land Council are concluded between an applicant for an exploration permit and the Council:

(a) if the applicant withdraws its application – on the day the application is withdrawn; or

(b) if the Minister withdraws consent to negotiate – on the day the consent is withdrawn; or

(c) on the day the Council notifies the applicant, in writing, of its decision to consent or refuse to consent to the grant of the exploration permit.

consent to negotiations means the Minister's consent to an applicant for an exploration permit entering into (and proceeding with) negotiations with a Land Council for the Council's consent to the grant of the exploration permit.

Minister means the Northern Territory Mining Minister as defined in ALRA.

Note: This section should be read in conjunction with Part IV of ALRA which governs negotiations between the applicant for the exploration permit and the Land Council. This vests certain powers in relation to the negotiations in the Commonwealth Minister but it should be noted that some of these may be delegated to the NT Minister under section 76 of ALRA.

14. Applicant for licence to hold exploration permit

(1) Subject to subsection (2), a person shall not apply for or be granted a licence in relation to Aboriginal land unless, at the time of the application for that licence, he was the holder of an exploration permit in relation to that land.

(2) Subsection (1) shall not apply to or in relation to a person who:

(a) is, in relation to that land, a traditional Aboriginal owner within the meaning of the Land Rights Act;

(b) had made an application for a licence over the land before it became Aboriginal land; or

(c) made an application under the repealed Act for a lease in respect of Aboriginal land which application, by virtue of section 119, is deemed to be an application for a licence under this Act.

15. Environmental consideration relating to certain parks and reserves

(1) In respect of land comprising the whole or a part of a park or reserve, the Minister shall not grant:

(a) subject to subsection (2), an exploration permit or retention licence, unless he has considered the opinions of the minister administering the *Territory Parks and Wildlife Conservation Act* in relation to the proposed grant; or

(b) a production licence, except in accordance with the conditions, if any, specified by the minister administering the *Territory Parks and Wildlife Conservation Act*.

(2) Notwithstanding subsection (1)(a), the Minister shall not grant an exploration permit or retention licence in respect of land comprising the whole or part of a wilderness zone except in accordance with the conditions, if any, specified by the minister administering the *Territory Parks and Wildlife Conservation Act*.

(3) A permittee or retention licensee shall not carry out his technical works programme, or any other exploration, which may cause substantial disturbance to the surface of land comprising the whole or a part of a park or reserve unless he has advised the Minister, in writing, of his intention to carry out the activity and he carries it out in accordance with such directions, if any, as the Minister thinks fit, or which are required under subsection (4) to be given, to protect the environment in or in the vicinity of the park or reserve.

(4) The minister administering the *Territory Parks and Wildlife Conservation Act* may require the Minister to give as directions under subsection (3) such directions in relation to the protection of the environment in the park or reserve as the minister thinks fit, and the Minister shall give those directions accordingly.

Divisions 2, 3 & 4 – Administration and conditions of permits and licences

Division 2: Exploration permits for petroleum

16. Application for exploration permit

(1) The Minister may, by notice published in a newspaper circulating throughout Australia and in any other way the Minister considers appropriate, invite applications for the grant of an exploration permit for any of the blocks specified in the notice.

(2) The notice must include the following information:

(a) the period during which applications may be made (the application period);

(b) the designated number of each block specified in the notice;

(c) if Part IIA or IIB applies to the grant of an exploration permit for any of those blocks – a statement to that effect;

(d) the place at which copies of the guidelines in relation to the making of an application are available for inspection;

(e) any other information the Minister considers appropriate.

(3) An application for the grant of an exploration permit must contain:

(a) the name and address of the applicant; and

(b) the designated number of each block the subject of the application; and

(c) a map clearly delineating:

(i) the application area, which must not exceed 200 adjoining blocks; and

(ii) the boundaries of existing exploration permit or licence areas in the immediate vicinity of the application area; and

(d) a proposed technical works programme for exploration of the blocks during each year of the term of the proposed exploration permit; and

(e) evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme and to comply with this Act; and

(f) if the application is made by 2 or more persons, the proposed sharing arrangements between the applicants; and

(g) the name of the designated operator and evidence of the technical capacity of the operator to carry out the proposed technical works programme; and

(h) the prescribed application fee; and

(i) other relevant information in support of the application.

(4) A person may apply for the grant of one or more exploration permits.

(5) The Minister may, by written notice to an applicant, request:

(a) further information relevant to the applicant or application; or

(b) an amendment or variation of the application.

17. More than one application for same block or blocks

(1) This section applies in relation to 2 or more applications for the grant of an exploration permit if:

(a) the application period has ended; and

(b) the Minister has completed the procedures relevant to any requests under section 16(5); and

(c) the application areas cover all or some of the same blocks.

(2) The Minister must decide, in accordance with the guidelines, which application has the greatest merit to be given consideration for the grant of an exploration permit.

(3) The Minister must, as soon as practicable after making the decision, give each applicant whose application was unsuccessful a notice stating the reasons for the decision.

18. Notice of application for exploration permit

(1AA) This section applies in relation to an application for the grant of an exploration permit as soon as practicable:

(a) after the end of the application period; or

(b) if the Minister has made a request under section 16(5)(a) – after the Minister has received all relevant information; or

(c) if the Minister has made a request under section 16(5)(b) – after all matters relevant to the amendment or variation have been completed in accordance with the guidelines; or

(d) if the Minister has made a decision under section 17(2) – after giving notice under section 17(3).

(1) The Minister must cause to be published, at the expense of the applicant, in a newspaper circulating in the part of the Territory in which the application area is situated, or in any other publication that the Minister thinks fit, a notice containing:

(c) the name of the applicant; and

(d) a description of the application area sufficient to enable it reasonably to be identified or a map upon which the proposed boundaries of the application area are indicated by reference to named geographical features; and

(e) a statement to the effect that a person who has an estate or interest in relation to land comprised in, or land contiguous with land comprised in, an application area may, within 2 months after the notice is published in the newspaper or other publication, lodge in writing with the Minister an objection to the grant.

(1A) If Part IIA or IIB applies, the relevant registered native title claimants, registered native title bodies corporate and representative Aboriginal/Torres Strait Islander bodies are to be served with notice in accordance with section 57F or 57T, as the case requires.

(2) The Minister may direct an applicant to serve a copy of a notice under subsection (1) on a person named in the direction.

(3) A person who does not have an estate or interest in relation to land comprised in, or land contiguous with land comprised in, an application area is not entitled to lodge an objection to the granting of an exploration permit in respect of the application area.

19. Objections

(1) Subject to section 18(3), objections to the grant of an exploration permit may be lodged in response to a notice published under section 18(1) in accordance with the statement referred to in section 18(1)(e).

(2) The Minister must give to the applicant copies of the objections (if any) lodged under subsection (1), together with a notice to the effect that, within 30 days after the date of the notice, the applicant may lodge with the Minister replies to or other comments about the objections.

(3) Any native title objection lodged in accordance with this section by a registered native title claimant or registered native title body corporate is to be dealt with under Parts IIA or IIB as applicable.

20. Determination of application for exploration permit

(2) After the date specified in the notice given under section 19(2), the Minister must consider the following:

(a) the application;

(b) any objections to the grant of the exploration permit;

(c) any replies or other comments of the applicant;

(d) any other information supplied to the Minister as requested under section 16(5)(a);

(e) any other matter the Minister considers relevant to the application.

(3) The Minister must then, subject to section 57L, determine whether to grant the exploration permit in respect of some or all of the blocks to which the application relates or refuse to grant the exploration permit.

(4) If the Minister determines to grant the exploration permit, the Minister must give the applicant a notice stating the following:

(a) the conditions subject to which the Minister is prepared to grant the exploration permit;

(b) the date, which must be at least 28 days after the date of the notice, when the application will lapse if the Minister has not received the applicant's written acceptance of those conditions.

(5) If the Minister receives the applicant's written acceptance of the conditions within the specified time, the Minister must grant the applicant the exploration permit subject to those conditions.

(6) If the Minister determines to refuse to grant the exploration permit, the Minister must, as soon as practicable, give the applicant a notice of the determination stating:

(a) the reasons for the determination; and

(b) the applicant may apply for a review of the determination under Division 6.

21c. No grant of exploration permit for area if permit etc. already granted

The Minister must not grant an exploration permit in relation to an area that is the subject of another exploration permit or a licence.21E Guidelines

(1) The Minister must issue guidelines relating to the making, and consideration and determination of, an application for the grant of an exploration permit.

(2) The Minister must give notice in the Gazette of the issuing of guidelines and specify in the notice the place at which copies of the guidelines may be inspected during normal business hours.

(3) The Minister must make the guidelines available for general inspection free of charge.

22. Term of exploration permit

(1) Subject to sections 28(3), 30(3), 73 and 74, an exploration permit remains in force for 5 years commencing on the day on which it was granted or last renewed.

(2) The Minister may not renew an exploration permit more than twice.

23. Application for renewal of exploration permit

(1) Subject to sections 24 and 24A and to Parts IIA and IIB as applicable, a permittee may apply to the Minister to renew the permittee's exploration permit in relation to the blocks specified in the application.

(2) For the purposes of subsection (1), an application for the renewal of an exploration permit shall be:

(a) in an approved form;

(b) made in an approved manner;

(c) accompanied by the prescribed fee; and

(d) accompanied by a report of the action taken by the permittee to restore and rehabilitate the land comprising the blocks that are part of the permittee's exploration permit area, but are not specified in the application, and the areas adjacent to that land which are or may be affected by the permittee's operations on those blocks.

(3) In relation to an application for a renewal of an exploration permit, the Minister:

(a) shall, where the application is received not earlier than 6 months before, but not later than 3 months before, the expiration of the exploration permit;

(b) may, where the application is received later than 3 months before the expiration of the exploration permit; and

(c) shall not, where the application is received after the expiration of the exploration permit, accept the application.

24. Application for renewal of exploration permit to be in relation to reduced area

(1) Subject to subsection (3) and section 24A, the number of blocks in relation to which an application for the renewal of an exploration permit may be made shall not exceed:

(a) where the number of blocks in respect of which the permit is in force is a number that is divisible by 2 without remainder – one-half of that number; or

(b) where the number of blocks in respect of which the permit is in force is a number that is not divisible by 2 without remainder – one-half of the number arrived at by increasing the number of blocks by one.

(2) In an application for the renewal of an exploration permit:

(a) the blocks specified in the application shall constitute a single area, or a number of discrete areas each comprised of 2 or more blocks; and

(b) each block, in a discrete area referred to in paragraph (a), shall have a side in common with at least one other block in the area.

(3) Subject to subsection (4), where the number of blocks in respect of which an application for the renewal of an exploration permit may be made is 12 or more, each area constituted by blocks in respect of which the application is made shall be constituted by not less than 12 blocks.

(4) The Minister may accept an application for the renewal of an exploration permit notwithstanding that it does not comply with subsection (3).

(5) Where the maximum number of blocks in respect of which an application for the renewal of an exploration permit may be made is less than 12, the Minister may, by notice served on the permittee:

(a) inform the permittee that he will accept an application only in respect of the number of blocks, not exceeding 12, as is specified in the notice; and

(b) give such directions as he thinks fit concerning the blocks in respect of which the application may be made.

24A. Exemption from requirement to reduce permit area

(1) A permittee who applies under section 23 for the renewal of the permittee's exploration permit may also apply to the Minister for an exemption, for a period not exceeding 12 months, from the requirement to reduce the number of blocks as required by section 24(1).

(2) An application for an exemption must give reasons why the permittee seeks the exemption.

(3) An exemption may provide for:

(a) a deferral of the reduction of the permit area; or

(b) a reduction of the permit area by a lesser number of blocks than would otherwise be required or permitted under section 24.

(4) The Minister may grant an exemption and accept the application for renewal of the permittee's exploration permit only if satisfied:

(a) with the extent to which the permittee has complied with this Act, the conditions to which the exploration permit is subject, and any directions lawfully given by the Minister; and

(b) that, if the exploration permit is renewed, the exemption:

(i) will assist the permittee to more effectively carry out the permittee's technical works programme, or other exploration of the permit area, for the discovery of a commercially exploitable accumulation of petroleum; and

(ii) will be in the best interests of the Territory.

(5) An exemption granted under subsection (4) must be in writing and specify the period, not exceeding 12 months, for which the exemption is granted.

(6) Before the end of a period of exemption, the permittee may apply for an extension of the exemption and, if the Minister is satisfied about the matters mentioned in subsection (4), the Minister may extend the exemption for a period not exceeding 12 months.

25. Grant or refusal of renewal of exploration permit

(1) Where a permittee makes an application for the renewal of the permittee's exploration permit and the Minister accepts the application, subject to Parts IIA and IIB as applicable, the Minister:

(a) shall, where the permittee has complied with the conditions to which the exploration permit is subject, the directions, if any, lawfully given to the permittee by the Minister and with this Act; or

(b) may, where the permittee has not so complied and the Minister is satisfied that, although the permittee has not so complied, circumstances exist that justify the renewal of the exploration permit, by notice, inform the permittee that:

(c) the Minister is prepared to renew the exploration permit on the permittee lodging a security for compliance with the conditions to which the permit will from time to time be subject, the directions, if any, lawfully given to the permittee by the Minister and with this Act.

(2) Where a permittee has not complied with the conditions to which the permittee's exploration permit is subject, the directions, if any, lawfully given to the permittee by the Minister or with this Act and the Minister is not satisfied that circumstances exist that justify the granting of the renewal of the permit, the Minister shall, subject to subsection (3), by notice served on the permittee, refuse to renew the permit.

(2A) A notice of the Minister's refusal to renew an exploration permit must include the reasons for the refusal and a statement that the permittee may request a review of the determination under Division 6.

(3) The Minister shall not refuse to renew an exploration permit unless the Minister has:

(a) by notice served on the permittee, given not less than 28 days notice of the Minister's intention to refuse to renew the exploration permit;

(b) in the notice:

(i) given particulars of the reasons for the intention; and

(ii) specified a date on or before which the permittee may, by notice served on the Minister, submit any matters that the permittee wishes the Minister to consider; and

(c) considered any matter so submitted by the permittee to the Minister on or before the specified date.

(4) A notice under subsection (1) shall contain:

(a) a statement of the conditions to which the exploration permit on its renewal is to be subject; and

(b) a statement to the effect that the application will lapse if the permittee does not make a request under subsection (5) and lodge with the Minister the security referred to in the notice.

(5) A permittee who has been served with a notice under subsection (1) may, within 28 days after the date of service of that notice on the permittee or any other longer period agreed to by the Minister:

(a) by notice served on the Minister, request the Minister to renew the exploration permit; and

(b) lodge with the Minister the security referred to in the notice served under subsection (1).

(6) Where a permittee who has been served with a notice under subsection (1) has:

(a) made a request under subsection (5); and

(b) lodged with the Minister the security referred to in the notice, within the period referred to in subsection (5), the Minister shall renew the exploration permit.

(10) Where a permittee has been served with a notice under subsection (1) and has not, within the period referred to in subsection (5), made the request and lodged with the Minister the security referred to in that subsection, the application lapses on the expiration of that period.

(11) Where:

(a) an application for the renewal of an exploration permit has been accepted; and

(b) the exploration permit expires before:

(i) the Minister renews, or refuses to renew, the permit; or

(ii) the application lapses as provided by subsection (10), the permit shall be deemed to continue in force in all respects until:

(c) the Minister renews or refuses to renew the permit; or

(d) the application so lapses, as the case may be.

26. Annual fee

(1) The annual fee payable in relation to an exploration permit is:

(a) the prescribed amount per block per annum; or

(b) the prescribed annual amount, whichever is greater.

(2) Subject to section 63, the annual fee for an exploration permit:

(a) is payable in advance; and

(b) is calculated on the number of blocks held, by the permittee on the anniversary of the commencement of the permittee's exploration permit or its last renewal.

27. Conditions of exploration permit

Subject to this Part and to Parts IIA and IIB as applicable, an exploration permit may be granted or renewed subject to such conditions as the Minister thinks fit and specifies in the permit document.28 Variation etc. of condition of exploration permit

(1) Subject to Parts IIA and IIB as applicable, a permittee may apply to the Minister to vary, suspend or waive a condition of the permittee's exploration permit.

(2) Subject to Parts IIA and IIB as applicable, on receiving an application under subsection (1), the Minister may, by notice served on the permittee, vary, suspend or waive a condition of the exploration permit, in accordance with the application.

(3) Where a condition of an exploration permit which places an obligation on the permittee is suspended under subsection (2), the Minister may, in the notice of suspension or by a later instrument served on the permittee, extend the term of the permit by a period not exceeding the period of the suspension.

(4) Where an extension under subsection (3) of the term of an exploration permit is expressed to have effect from a date earlier than the date on which the notice by which it is extended is signed, it shall have and be deemed to have had effect as if the notice had been signed on that earlier date.

29. Rights conferred by exploration permit

(1) An exploration permit, while it remains in force, gives the permittee, subject to this Act and in accordance with the conditions to which the permit is subject and the directions, if any, lawfully given by the Minister, the exclusive right to explore for petroleum, and to carry on such operations and execute such works as are necessary for that purpose, in the exploration permit area.

(2) Without limiting the generality of subsection (1) but subject to this Act and any condition or direction referred to in that subsection, a permittee or, if there is more than one, the permittees jointly and his agents and employees may:

(a) at any time, enter and remain in the exploration permit area with such vehicles, vessels, machinery and equipment as are necessary or convenient for carrying out the technical works programme or other exploration of the permit area;

(b) carry out the technical works programme and other exploration for petroleum in the exploration permit area;

(c) extract, remove or allow the release from the exploration permit area for sampling and testing, an amount of material reasonably necessary for the purpose of establishing the presence of petroleum, or such greater amount as is approved; and

(d) subject to any prior lawful activity and to the directions, if any, of the Minister, use the water resources of the exploration permit area for his domestic use and for any purpose in connection with his approved technical works programme and other exploration.

(3) Where a permittee has:

(a) complied with the conditions to which the permittee's exploration permit is subject, the directions, if any, lawfully given to him by the Minister and with this Act;

(b) discovered a commercially exploitable accumulation of petroleum within the permittee's exploration permit area; and

(c) under section 45, applied for a production licence in relation to the blocks where the accumulation occurs, the Minister shall, subject to Division 4, to Parts IIA and IIB (as applicable) and to such conditions as the Minister may think fit, grant to him a production licence.

30. Notice to apply for production licence

(1) Subject to subsection (6), where the Minister is satisfied that a commercially exploitable accumulation of petroleum may occur in an exploration permit area, the Minister may, by notice served on the permittee, require the permittee to show cause why the permittee should not apply for a production licence in relation to the blocks where the accumulation may occur and specify a date, being not earlier than 6 months after the date of the notice, before which the permittee should show cause.

(2) Subject to subsection (5), where a permittee has been served with a notice under subsection (1) and he fails to show cause to the satisfaction of the Minister, before the date specified in the notice, the Minister may, by notice served on the permittee, direct him to apply for a production licence and specify a date,

being not earlier than 6 months after the date of the notice under this subsection, before which he shall apply for the production licence.

(3) Subject to subsection (5), where, under subsection (2), a permittee has been directed to apply for a production licence before the date specified in the notice and he has failed to so apply, the Minister may, by notice served on the permittee, cancel the exploration permit in relation to the blocks specified in the notice under subsection (1).

(4) The Minister may, by notice served on the permittee, vary the date in a notice under subsection (1) or (2) so as to allow a longer period for the permittee to show cause or apply for the production licence as required by the notice under subsection (1) or (2), as the case may be.

(5) Where a notice under subsection (1) or (2) has been served on a permittee and he has made an application to the Minister for a retention licence in relation to the blocks to which such a notice relates, the Minister may not exercise his powers under this section until the application for a retention licence has been determined.

(6) The Minister may not exercise his powers under this section:

(a) during the first term of the exploration permit; or

(b) if the blocks where the commercially exploitable accumulation of petroleum may occur are, in whole or part, Aboriginal land and no agreement has been reached under the Land Rights Act either between the permittee and the Land Council or as otherwise permitted under that Act, in relation to the production of petroleum in that area.

Division 3: Retention licences

31. Entitlement to apply for retention licence

Where a permittee has:

(a) by drilling operations in the permittee's exploration permit area, established the presence of petroleum;

(b) given notice, under section 64, to the Minister of the presence of the petroleum in the permittee's exploration permit area; and

(c) satisfied the Minister that the petroleum present in the permittee's exploration permit area is potentially of a commercial quality and quantity, the permittee may apply for one or more retention licences in relation to the whole or part of the permit area.

32. Application for retention licence

(1) Subject to this Act, including Part IIA if applicable, a permittee may apply for a retention licence by lodging with the Minister:

(a) a statement containing the name and address of the applicant;

(b) a statement containing the designated number of each block the subject of the application;

(c) a map clearly delineating the application area and the boundaries of the existing exploration permit area from which the application area is to be excised;

(d) evidence, satisfactory to the Minister, that:

(i) the applicant is the permittee of the application area;

(ii) the applicant has established the presence of petroleum within the application area and notified, under section 64, the Minister of the presence of petroleum; and

(iii) although the petroleum present is potentially of a commercial quality and quantity, production from the application area is not, at the present time, commercially viable;

(e) a proposed technical works programme for the exploration, appraisal and development of petroleum within the application area, including an economic appraisal in relation to the presence of petroleum, during the period of the proposed licence;

(f) evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme and to comply with this Act;

(g) where the application is made by 2 or more persons, the proposed sharing arrangements between the applicants;

(j) the prescribed application fee;

(k) a statement of the reasons why the applicant:

(i) believes that an appraisal of the application area cannot be carried out during the unexpired term of the exploration permit; and

(ii) has not applied for a production licence in relation to the application area; and

(m) such other information in support of the application as the applicant thinks fit. (2) Where the Minister has received an application for a retention licence, the Minister may, by notice served on the applicant, request further information in relation to the applicant or the application.

33. Size of retention licence area

(1) A permittee shall not apply for a retention licence in respect of an area which is constituted by more than 12 blocks.

(2) A permittee shall not apply for a retention licence in respect of an area which is constituted by more than one block unless the blocks form a discrete area which conforms to an approved shape.

34. Grant or refusal of retention licence

(1) Where the Minister:

(a) has received an application under section 32;

(b) is satisfied that the applicant has complied with the requirements of this Act relating to an application for a retention licence; and

(c) is satisfied that the applicant, as a permittee, complied with the provisions of this Act relating to the exploration permit and the exploration permit area and the lawful directions, if any, given to him by the Minister, subject to Parts IIA and IIB as applicable, the Minister may determine to grant the retention licence, subject to such conditions as he thinks fit, or refuse to grant it.

(2) Where the Minister determines under subsection (1) to grant a retention licence, he shall give notice to the applicant of:

(a) the conditions subject to which he is prepared to grant it; and

(b) the date, not being earlier than 28 days after the date of the notice, upon which the application shall lapse unless the Minister has received from him an acceptance of the conditions specified in the notice.

(3) Where the Minister receives from an applicant, within the time specified, a written acceptance of the conditions specified in a notice under subsection (2), he shall grant to the applicant a retention licence, subject to those conditions.

(4) Where the Minister determines not to grant a retention licence he shall, as soon as practicable after he has so determined, serve notice of his refusal on the applicant.

(5) A notice of the Minister's refusal to grant a retention licence must include the reasons for the refusal and a statement that the applicant may request a review of the determination under Division 6.

35. Exploration permit not affected

The term and area of an exploration permit are not affected by:

(a) an application for a retention licence; or

(b) the determination of the Minister not to grant a retention licence.

36. Term of retention licence

Subject to sections 43(3), 73 and 74, a retention licence remains in force for a period of 5 years commencing on the date on which it was granted or last renewed.37 Application for renewal of retention licence

(1) Subject to Part IIA if applicable, a retention licensee may apply to the Minister to renew his retention licence.

(2) For the purposes of subsection (1), an application for the renewal of a retention licence shall be:

(a) in an approved form;

(b) made in an approved manner; and

(c) accompanied by the prescribed fee.

(3) In relation to an application for a renewal of a retention licence, the Minister:

(a) shall, where an application for the renewal of a retention licence is received not earlier than 6 months, but not later than 3 months, before the expiration of the licence;

(b) may, where the application is received later than 3 months before the expiration of the licence; and

(c) shall not, where the application is received after the expiration of the licence, accept the application.

38. Grant or refusal of renewal of retention licence

(1) Where, under section 37, the Minister accepts an application by a retention licensee for the first renewal of the licensee's retention licence, the Minister:

(a) shall, where the retention licensee has complied with the conditions to which the licence is subject, the lawful directions, if any, given to the licensee by the Minister and with this Act; or

(b) may, where the retention licensee has not so complied and the Minister is satisfied that, although the licensee has not so complied, circumstances exist that justify the renewal of the licence, by notice in

writing, inform the licensee that, subject to Parts IIA and IIB as applicable, the Minister is prepared to renew the licence.

(2) Where, under section 37, the Minister accepts an application by a retention licensee for the renewal of the licensee's retention licence, other than the first renewal of the retention licence, the Minister may inform the licensee, by notice served on the licensee, that the Minister is prepared to renew the retention licence and, if the retention licence is so renewed, it is renewed for a term of 5 years.

(3) Where, under section 37, the Minister accepts an application by a retention licensee for the renewal of the licensee's retention licence but the retention licensee has not complied with the conditions to which the licence is subject, the lawful directions, if any, given to the licensee by the Minister and this Act and, in the case of an application for the first renewal of the retention licence, the Minister is not satisfied that circumstances exist that justify the renewal of the licence, the Minister shall, subject to subsection (5), by notice served on the retention licensee, refuse to renew the licence.

(3A) A notice of the Minister's refusal to renew a retention licence must include the reasons for the refusal and a statement that the retention licensee may request a review of the determination under Division 6.

(4) Before exercising his or her powers under subsection (1), (2) or (3), the Minister may, by notice served on the applicant, require the applicant to lodge with the Minister, before the date specified in the notice:

(a) an analysis of the work undertaken and expenditure incurred during the term of the licence and details of the results of the work;

(b) a statement of the reasons why the applicant has not applied for a production licence in relation to the licence area;

(c) a technical works programme for the term of the proposed renewal; and

(d) such other information as the Minister thinks fit.

(5) The Minister shall not refuse to renew a retention licence unless the Minister has:

(a) by notice served on the retention licensee, given not less than 28 days notice of the Minister's intention to refuse to renew the licence;

(b) in the notice:

(i) given particulars of the reasons for the Minister's intention to refuse to renew the licence; and

(ii) specified a date on or before which the retention licensee may, by notice served on the Minister, submit any matters that the licensee wishes the Minister to consider; and

(c) taken into account any matters so submitted to the Minister on or before the specified date by the retention licensee.

(6) Notices under subsections (1) and (2) shall contain:

(a) a statement of the conditions to which the retention licence on its renewal is to be subject; and

(b) a statement to the effect that the application will lapse if the retention licensee does not make a request under subsection (7).

(7) A retention licensee who has been served with a notice under subsection (1) or (2) may, within 28 days after the date of service of that notice on the retention licensee or any other longer period agreed to by the Minister:

(a) by notice served on the Minister, request the Minister to renew the retention licence; and

(b) lodge with the Minister the security referred to in the notice served under subsection (1) or (2).

(8) Where a retention licensee has been served with a notice under subsection (1) or (2) and has, within the period referred to in subsection (7), made the request and lodged with the Minister the security referred to in that subsection, the Minister shall renew the retention licence subject to the conditions specified in the notice under subsection (1) or (2), as the case may be.

(12) Where a retention licensee has been served with a notice under subsection (1) or (2) but has not made the request and lodged with the Minister the security referred to in subsection (7) within the period referred to in that subsection, the application lapses on the expiration of that period.

(13) Where:

(a) an application for the renewal of a retention licence has been accepted; and

(b) the retention licence would, but for this subsection, expire before:

(i) the Minister renews, or refuses to renew, the retention licence; or

(ii) the application lapses as provided by subsection (12), the retention licence shall be deemed to continue in force in all respects until:

(c) the Minister renews, or refuses to renew, the retention licence; or

(d) the application so lapses, as the case may be.

39. Annual fee

(1) The annual fee payable in relation to a retention licence is the prescribed amount per block per annum.

(2) Other than in relation to the first year of the retention licence after it is granted or renewed for the purposes of subsection (1), the annual fee:

(a) is payable in advance; and

(b) is calculated on the number of blocks held, by the licensee on the anniversary of the commencement of his licence or its last renewal.

40. Conditions of retention licence

Subject to this Part and to Parts IIA and IIB as applicable, a retention licence may be granted subject to such conditions as the Minister thinks fit and specifies in the licence document.41 Variation, &c., of conditions of retention licence

(1) Subject to Part IIA if applicable, a retention licensee may apply to the Minister to vary, suspend or waive a condition of his licence.

(2) Subject to Parts IIA and IIB as applicable, on receiving an application under subsection (1), the Minister may, by notice served on the licensee, vary, suspend or waive a condition of the licence, in accordance with the application.

(3) Where a retention licensee has applied under subsection (1) to vary, suspend or waive a condition of his licence which relates to the technical works programme, the Minister may, after consultation with the retention licensee, appoint a person to evaluate the proposed variation, suspension or waiver and report his findings to the Minister.

(4) Where the Minister appoints a person under subsection (3), the cost of the person's services shall be a debt due and payable by the retention licensee to the Territory.

42. Rights conferred by retention licence

(1) A retention licence, while it remains in force, gives the retention licensee or, if there is more than one, the retention licensees jointly, subject to this Act and in accordance with the conditions to which the licence is subject and the directions, if any, lawfully given by the Minister, the exclusive right to carry on in the licence area such geological, geophysical and geochemical programmes and other operations and works, including appraisal drilling, as are reasonably necessary to evaluate the development potential of the petroleum believed to be present in the licence area.

(2) Where a retention licensee has:

(a) complied with the conditions of the retention licensee's licence, the lawful directions (if any) of the Minister and this Act;

(b) applied, in accordance with Division 4, for a production licence in relation to the whole or part of the licensee's retention licence area; and

(c) discovered a commercially exploitable accumulation of petroleum within the licensee's retention licence area, the Minister shall, subject to Division 4, to Parts IIA and IIB (as applicable) and to such conditions as the Minister thinks fit, grant to the licensee a production licence.

43. Notice to apply for production licence

(1) Subject to subsection (5), where the Minister is satisfied that commercial production of petroleum should commence in a retention licence area, he may, by notice served on the retention licensee, require him to show cause why he should not apply for a production licence in relation to the blocks where the commercially exploitable accumulation of petroleum occurs and specify a date, being not earlier than 6 months after the date of the notice, by which the licensee should show cause.

(2) Where a retention licensee has been served with a notice under subsection (1) and he fails to show cause to the satisfaction of the Minister, within the time specified in the notice, the Minister may, by notice served on the retention licensee, direct him to apply for a production licence and specify a date, being not earlier than 3 months after the date of the notice, by which the licensee should apply for the production licence.

(3) Where, under subsection (2), a retention licensee has been directed to apply for a production licence before a date specified in the direction and the licensee has failed to so apply, the Minister may, by notice served on the licensee, cancel his licence.

(4) The Minister may, by notice served on a retention licensee, vary the date in a notice under subsection (1) or (2) so as to allow a longer period for the retention licensee to show cause or apply for a production licence.

(5) The Minister may not exercise his powers under this section if the blocks where the commercially exploitable accumulation of petroleum occurs are, in whole or part, Aboriginal land and no agreement in relation to the production of petroleum in that area has been reached under the Land Rights Act between the retention licensee and the Land Council or as otherwise permitted under that Act.

Division 4: Production licences

44. Applicant

A person who is:

(a) a permittee; or

(b) a retention licensee, may apply for a production licence in relation to the whole or part of his or her exploration permit or licence area.

45. Application for production licence

(1) Subject to this Act, including Part IIA if applicable, a permittee or licensee may apply for a production licence by lodging with the Minister:

(a) a statement containing the name and address of the applicant;

(b) a statement containing the designated number of each block the subject of the application;

(c) a map clearly delineating the application area and the boundaries of the existing exploration permit or retention licence area in which the application is comprised;

(d) a proposed technical works programme specifying the proposals for exploration, appraisal and production of petroleum from within the proposed licence area;

(e) evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme and to comply with this Act;

(f) proposals for the protection of the environment, including proposed measures to be undertaken by the applicant for the rehabilitation of the licence area or other affected areas;

(g) where the application is made by 2 or more persons, the proposed sharing arrangements between the applicants;

(j) the prescribed application fee; and

(k) such other information in support of the application as the applicant thinks fit.

(1A) If Part IIA applies, the relevant registered native title claimants, registered native title bodies corporate and representative Aboriginal/Torres Strait Islander bodies are to be served with notice of the application in accordance with that Part.

(2) Where the Minister has received an application for a production licence, the Minister may, by notice served on the applicant, request further information in relation to the applicant or the application.

(3) A permittee or licensee may apply for one or more production licences.

46. Size of production licence

(1) A person shall not apply for a production licence in respect of an area which is constituted by more than 12 blocks.

(2) A person shall not apply for a production licence in respect of an area which is constituted by more than one block unless the blocks form a discrete area which conforms to an approved shape.

(3) The Minister may grant a production licence in respect of:

(a) an area of less than one block; or

(b) blocks which form more than one discrete area, where he is of the opinion that circumstances justify his doing so or it is in the public interest to do so.

47. Grant of production licence

(1) Where the Minister:

(a) has received an application under section 45;

(b) is satisfied that the applicant has complied with the requirements of this Act relating to an application for a production licence; and

(c) is satisfied that he or she is required under section 29(3) or 42(2) to grant to the applicant a production licence in relation to specific blocks, subject to section 57L if applicable, the Minister must determine to grant to the applicant the production licence subject to conditions.

(2) Where the Minister:

(a) has received an application under section 45; and

(b) is satisfied that, although the applicant has not complied with the conditions under which the applicant's exploration permit or licence was granted, the lawful directions, if any, given to the applicant by the Minister or this Act, circumstances exist that justify the granting of the production licence, subject to section 57L if applicable, the Minister may determine to grant to the applicant the production licence subject to conditions or refuse to grant it.

(3) Where the Minister exercises his or her power under subsection (1) or (2) and determines to grant to an applicant a licence, the Minister shall grant a licence only in relation to the minimum number of blocks which, in his or her opinion, is reasonably necessary for the applicant to fully exploit the commercially exploitable accumulation of petroleum which occurs in the application area.

(4) Where the Minister determines under subsection (1) or (2) to grant a production licence, he or she shall give notice to the applicant of:

(a) the conditions subject to which he or she is prepared to grant it; and

(b) the date, not being earlier than 28 days after the date of the notice, after which the application is to lapse unless the Minister has received from the applicant a written acceptance of the conditions specified in the notice.

(5) If the Minister receives from an applicant within the time specified in subsection (4)(b) a written acceptance of the conditions specified in the notice referred to in subsection (4), the Minister must grant to the applicant the production licence subject to those conditions.

(6) If the Minister does not receive a written acceptance of the conditions specified in the notice referred to in subsection (4) from an applicant within the time specified in subsection (4)(b):

(a) the Minister must not grant the applicant the production licence; and

(b) the applicant's application lapses on the expiry of the time specified in subsection (4)(b).

48. Refusal to grant production licence

(1) Where the Minister determines to refuse to grant a production licence he shall, as soon as practicable after he has so determined, serve notice of his determination on the applicant.

(1A) The notice of determination must include the reasons for the refusal to grant a production licence and a statement that the applicant may apply for a review of the determination under Division 6.

(2) The Minister may not determine to refuse to grant a licence, unless he has:

(a) by notice served on the applicant, given not less than 28 days notice of his intention to refuse to grant the licence;

(b) in the notice, specified:

(i) the reasons for his intended refusal; and

(ii) a date on or before which the applicant may, by notice served on the Minister, submit any matters he wishes the Minister to consider; and

(c) taken into account any matters so submitted to him on or before the specified date by the applicant.

49. Exploration permit or licence not affected The term and area of an exploration permit or retention licence are not affected by:

(a) an application for a production licence; or

(b) the determination of the Minister not to grant a production licence.

50. Term of production licence

Subject to sections 73 and 74, a production licence remains in force for either 21 or 25 years as determined by the Minister commencing on the date on which it was granted or, in respect of the renewal of a production licence, the date on which it was last renewed, notwithstanding that it is renewed before the date on which it would otherwise have expired.51 Application for renewal of production licence

(1) Subject to Part IIA if applicable, a production licensee may apply to the Minister to renew his production licence.

(2) For the purposes of subsection (1), an application for the renewal of a production licence shall be:

(a) in an approved form;

(b) made in an approved manner; and

(c) accompanied by the prescribed fee.

(3) In relation to an application for the renewal of a production licence, the Minister:

(a) shall, where an application is received not earlier than 6 months before, but not later than 3 months before, the expiration of the production licence;

(b) may, where the application is received later than 3 months before the expiration of the licence; and

(c) shall not, where the application is received after the expiration of the licence, accept the application.

(4) In addition to subsection (3), the Minister may, where he is satisfied that there are commercial reasons that justify an application for the renewal of a production licence being made, accept the application being made at a time earlier than that specified in subsection (3)(a).

52. Grant or refusal of renewal of production licence

(1) Where, under section 51, the Minister accepts an application by a production licensee for the first renewal of his production licence, the Minister:

(a) shall, where the production licensee has complied with the conditions to which the licence is subject, the lawful directions, if any, given to him by the Minister and this Act; or

(b) may, where the production licensee has not so complied and the Minister is satisfied that, although the licensee has not so complied, circumstances exist that justify the renewal of the licence, by notice in writing, inform the licensee that, subject to Parts IIA and IIB as applicable, the Minister is prepared to renew the licence.

(2) Where, under section 51, the Minister accepts an application by a production licensee for the renewal of his production licence, other than the first renewal of the licence, the Minister may, by notice served on him, inform the production licensee that he is prepared to renew the production licence and, if the production licence is so renewed, it is renewed for such term, not exceeding 25 years, as is specified in the notice.

(3) Where, under section 51, the Minister accepts an application by a production licensee for the renewal of his production licence but the production licensee has not complied with the conditions to which his licence is subject, the lawful directions, if any, of the Minister and this Act and, in the case of an application for the first renewal of the production licence, the Minister is not satisfied that circumstances exist that justify the renewal of the licence, the Minister shall, subject to subsection (4), by notice served on the production licensee, refuse to renew the licence.

(3A) A notice of the Minister's refusal to renew a production licence must include the reasons for the refusal and a statement that the production licensee may request a review of the determination under Division 6.

(4) The Minister shall not refuse to renew a production licence unless he has:

(a) by notice served on the production licensee, given not less than 28 days notice of his intention to refuse to renew the licence;

(b) served a copy of the notice on such other persons, if any, as he thinks fit;

(c) in the notice:

(i) given particulars of the reasons for his intention to refuse to renew the licence; and

(ii) specified a date on or before which the production licensee may, by notice served on the Minister, submit any matters that he wishes the Minister to consider; and

(d) taken into account any matters so submitted to him on or before the specified date by the production licensee or by a person on whom a copy of the notice has been served under paragraph (b).

(5) Notices under subsections (1) and (2) shall contain:

(a) a statement of the conditions to which the production licence, on its renewal is to be subject; and

(b) a statement to the effect that the application will lapse if the production licensee does not make a request under subsection (6).

(6) Where a production licensee has been served with a notice under subsection (1) or (2), he may, within 28 days after the date of service of the notice on him, by notice served on the Minister, request the Minister to:

(a) renew the production licence; or

(b) amend the conditions contained in the notice under that subsection or the amount of the security to be lodged.

(7) Where a production licensee has been served with a notice under subsection (1) or (2) and has made a request under subsection (6)(a), within the period referred to in subsection (6), the Minister shall renew the production licence subject to the conditions specified in the notice under subsection (1) or (2), as the case may be, and subject to the conditions imposed in pursuance of section 57L if applicable.

(8) Where a production licensee has been served with a notice under subsection (1) or (2) and has made a request under subsection (6)(b), the Minister shall:

(a) consider the request; and

(b) by notice served on the licensee, inform him of the conditions to which the licence, on its renewal, is to be subject and the amount of the security to be lodged.

(9) Where a production licensee has been served with a notice under subsection (8)(b), he may, within 28 days after the date of service of the notice on him, by notice served on the Minister, request the Minister to renew the licence subject to the conditions specified in the notice under subsection (8)(b).

(10) Where a production licensee has served a notice under subsection (9), within the period referred to in that subsection, the Minister shall renew the licence.

(11) Where a production licensee has been served with a notice under subsection (1) or (2) but has not made a request under subsection (6), within the period referred to in subsection (6), the application lapses on the expiration of that period.

(12) Where:

(a) an application for the renewal of a production licence has been accepted; and

(b) the production licence would, but for this subsection, expire before:

(i) the Minister renews, or refuses to renew, the production licence; or

(ii) the application lapses as provided by subsection (11), the production licence shall be deemed to continue in force in all respects until:

(c) the Minister renews, or refuses to renew, the production licence; or

(d) the application lapses, as the case may be.

53. Annual fee

(1) The annual fee payable in relation to a production licence is the prescribed amount per block or part of a block per annum.

(2) Other than in relation to the first year of a production licence after it is granted or renewed, for the purposes of subsection (1), the annual fee:

(a) is payable in advance; and

(b) is calculated on the number of blocks held, by the production licensee on the anniversary of the commencement of his licence or its last renewal.

54. Conditions of production licence

(1) Subject to this Part and to Parts IIA and IIB as applicable, a production licence may be granted subject to such conditions as the Minister thinks fit and specifies in the licence document.

(2) Without limiting the generality of subsection (1), but subject to section 55, each production licence is subject to the condition that the production licensee:

(a) shall use the licence area continuously and exclusively for the purposes for which it is granted;

(b) shall not produce petroleum obtained from the licence area until the Minister authorises the commencement of production operations;

(c) shall pay royalties under this Act on petroleum produced; and

(f) shall, during such period of the term of the licence as is specified in the licence document, maintain an approved insurance policy, for:

(i) well redrilling and well recompletion expenses; and

(ii) damages arising out of damage to property or the environment, including by pollution, seepage or contamination.

55. Variation, &c., of conditions of production licence

(1) Subject to Part IIA if applicable, a production licensee may apply to the Minister to vary, suspend or waive a condition of his licence.

(2) Subject to Parts IIA and IIB as applicable, on receiving an application under subsection (1), the Minister may, by notice served on the licensee, vary, suspend or waive a condition of the licence, in accordance with the application.

(3) Where a production licensee has applied under subsection (1) to vary, suspend or waive a condition of his licence which relates to the technical works programme, the Minister may, after consultation with the production licensee, appoint a person to evaluate the proposed variation, suspension or waiver and report his findings to the Minister.

(4) Where the Minister appoints a person under subsection (3), the cost of the person's services shall be a debt due and payable by the production licensee to the Territory.

56. Rights conferred by production licence

A production licence, while it remains in force, gives the production licensee or, if there is more than one, the production licensees jointly, subject to this Act and in accordance with the conditions to which the licence is subject and the directions, if any, lawfully given by the Minister, the exclusive right:

(a) to explore for petroleum and recover it from the licence area; and

(b) to carry out such operations and execute such works in the licence area as are necessary for the exploration for and recovery of petroleum.

57. Declaration of restricted area

(1) A production licensee may, by notice in the Gazette and a newspaper circulating in that part of the Territory in which his production licence area is situated, declare his production licence area or part of that area to be a restricted area.

(2) Where a production licensee has, under subsection (1), declared a restricted area, he shall, within 3 months of the date of the notice in the Gazette fence the area.

(3) Where a production licensee fails to fence a restricted area within 3 months after the date of the notice in the Gazette, the declaration has no force or effect after the expiration of the 3 month period.

(4) The Minister may, by notice in the Gazette, repeal or vary a declaration under subsection (1).

(5) The production licensee has all the powers, in relation to the restricted area, of a person in lawful occupation of that area

Attachment C – Extracts from *Schedule of Onshore Petroleum Exploration and Production Requirements (2012)*

Contents

WELL INTEGRITY

501. Approval to Drill

(1) Operations to drill a new exploration, development or appraisal well or workover an existing well shall not be commenced without prior approval.

(2) An application under Sub-Clause (1) shall be made not less than one month (or 3 months if an environmentally sensitive area is involved), or such other period as may be approved, prior to the commencement of operations and shall include -

(a) proposed well name and number;

(b) location, elevation and co-ordinates of the well site;

(c) programmed depth;

(d) estimated spud-in date;

(e) estimated drilling time and costs;

(f) name and address of drilling contractor;

(g) type of rig and blow-out prevention equipment, including description of equipment and method of operation;

(h) names and addresses of other contractors involved in the operations and the nature of the services they will perform;

(i) detail of the drilling program, including particulars of casing program (with designs safety factors for burst, collapse and tension), complete casing cementation program, drilling fluid and formation evaluation procedures (cuttings and fluid sampling, coring, and wireline and mud logging);

(j) name of person responsible for communications with the Director;

(k) proposed well path;

(l) drilling procedures and well control manuals;

(m) geological prognosis which includes well objectives and, for exploration wells, play definition (source, seal, reservoir, trap .NT Onshore Petroleum Directions configurations) accompanied by a time or depth maps of near target horizon(s) and seismic sections where possible;

(n) emergency response plans and pollution control measures (including an oil spill contingency plan);

(o) a statement of proposed environmental protection and rehabilitation measures;

(p) evidence of adequate comprehensive insurance, including, but not limited to, public liability, loss of well control (including blowouts), relief well drilling, containment and clean-up; and

(q) such other information as the Director requests.

(3) The drilling program shall, in the case of an exploration well in a permit area, be accompanied by a current plan showing the existing land tenure i.e., reserves, private property, etc. in relation to the proposed drill site and access road and shall make reference to any other wells, public utilities or any other structure within 150 metres of the proposed well location.

(4) Any information not available at the time of initial application must be forwarded no later than one month prior to the expected spud date.

(5) An approved application shall not be varied without approval.

502. Approval of Drilling Equipment

503. Equipment to Conform to Certain Standards

Materials and equipment used in drilling and workover operations shall conform to the most recently published American Petroleum Institute (API) standards.

504. Location Survey

As soon as practicable after the spudding of a well, its location shall be determined to within an accuracy of 5 metres, or as required by the Director.

505. Prohibited Drilling Areas

A well shall not be drilled so that any part of it is less than 300 metres from a title boundary, except in accordance with a consent in writing of the Director.

506. Casing

(1) The design and placement of casing strings shall take into account known or predicted formation strength, known or predicted formation pore fluid pressures and programmed drilling fluid densities, and the maximum performance properties used in the design of casing strings shall be those indicated as minimum performance properties in API Bull 5C2 - "Bulletin on Performance Properties of Casing Tubing and Drill Pipe".

(2) Casing strings shall be run and cemented at the approximate setting depths specified in the drilling program and any significant variations to the prescribed setting depths shall be notified to the Director prior to running casing.

(3) All casing strings and liner strings shall be capable of withstanding all anticipated collapse and burst pressures, tensile loadings, temperatures, and environments likely to be encountered.

(4) All casing strings, other than liner strings shall extend to the wellhead.

(5) Casing recovered from a well shall not be re-used in another well unless inspection in accordance with API RP 5C1 – "Recommended Practice for Care and Use of Casing and Tubing" establishes compliance with Sub-Clause (3).

(6) A conductor casing string shall be installed to protect a well and equipment against surface formation instability and to enable the circulation of drilling fluid from the well before surface casing is installed.

(7) Surface casing shall be set at least 25m into a competent formation and, unless otherwise approved, to a depth of at least -

(a) 200 metres; and

(b) in relation to an exploration well where normal pressure gradients are anticipated, at least 15 per cent of the total depth to which uncased hole will be drilled to a depth of 2,500 metres, plus 5 per cent of the incremental depth of uncased hole beyond 2,500 metres; or

(c) in relation to an appraisal or development well where normal pressure gradients are known to exist, at least 10 per cent of the total depth to which uncased hole will be drilled.

(8) The design of the surface casing string shall take into account the support of other casing strings and the BOP stack.

(9) Where evidence indicates the possibility of above normal formation pore pressure, the surface casing design shall be considered on a well by well basis.

(10) Consideration shall be given to setting an intermediate casing string where -

(a) abnormal pressure, lost circulation or unstable zones are known or expected; or

(b) artesian water, high mud weights or extensive drilling time may lead to down-hole problems.

(11) When a liner string is installed there shall be an overlap of at least 30 metres between the top of the liner string and the shoe of the next larger casing string previously run.

(12) After cementing, all casing strings, except the conductor casing string, shall be pressure tested to an approved pressure before drilling out of the casing shoe or, in the case of production casing string, before proceeding with operations to complete or test a well, and such pressure test shall be held for as long as is necessary to ascertain that there is no continuous pressure drop and the result recorded in the driller's log.

(13) Drilling operations or operations to complete or test a well shall not commence until a satisfactory pressure test pursuant to Sub- Clause (12) has been obtained.

507. Cementing of Casing

(1) Unless otherwise approved conductor casing strings (other than those placed by jetting or driving) shall be cemented with sufficient cement to fill the annular space between the casing string and the wall of the hole from the shoe to surface.

(2) Surface casing strings shall be cemented with sufficient cement to fill the annular space between the casing string and the hole to a height of at least 450 metres above the shoe of the casing string, or to the surface if such casing string is less than 450 metres in length.

(3) Intermediate and production casing strings and liner strings shall be cemented with sufficient cement to fill the annular space between the casing string and the wall of the hole or next outer casing string as follows -

(a) from each cementing point (including the casing shoe) to a height of at least 150 metres above the cementing point;

(b) to a height of at least 100 metres above any zone not previously cased containing fluid hydrocarbons; and

(c) additionally, in the case of a liner string which is used as an intermediate or production casing string, the overlap between the liner string and the next larger casing string previously set shall be cemented to fill at least 30 metres measured length of annular space between the liner string and the next larger casing string, unless provision is made for the overlap to be sealed in some other effective manner or unless otherwise approved.

(4) All casing string cementations shall be carried out in accordance with good oil field practice and the details of the cementing operations shall be recorded in the driller's log and the daily drilling report. If there is any reason to suspect a faulty cementing operation, the Director shall be notified.

(5) After the cementing of casing strings, drilling shall not be commenced until a time lapse of -

(a) 24 hours; or

(b) 8 hours under pressure for the surface casing string and 10 hours under pressure for all other casing strings.

(6) For the purpose of Sub-Clause (5)(b) the cement is considered to be under pressure if, during the time referred to, the cement is restrained from movement by the use of float valves or other approved equipment.

(7) If the cementing requirements of this Clause have not been achieved by primary cementing operations, endeavours shall be made to meet those requirements by recementing or by remedial cementing, unless otherwise approved - n.b. the Director shall be notified of the failure to achieve the cementing requirements prior to commencing these endeavours.

508. Blow-out Prevention Control

(1) Blow-out preventers and related well control equipment shall be installed, operated, maintained and tested generally in accordance with API RP 53 - "Blow-out Prevention Equipment Systems for Drilling Wells" and shall be adequate to control expected pressures.

(2) Unless otherwise approved, prior to drilling below the conductor casing string in exploration wells, or in development or appraisal wells in those areas having known shallow gas accumulations, a diverter system incorporating a pipeline of adequate diameter with control valves shall be installed so as to safely divert hydrocarbons and other fluids in the event of pressures occurring below the shoe of the conductor string which may fracture the formation.

(3) Prior to drilling below the surface casing string the blow-out prevention equipment shall include a minimum of -

(a) three remotely controlled, hydraulically operated blow-out preventers with a working pressure that exceeds the maximum anticipated surface pressure, including one equipped with pipe rams, one with blind rams and one of the annular type; all ram type blow-out preventers shall be equipped with extension hand wheels or hydraulic locks;

(b) a drilling spool with at least two side outlets for the attachment of choke and kill lines, if side outlets are not provided in the blow-out preventer body. The side outlets shall be connected to pipelines of at least the same pressure rating as the blow-out preventer assembly. One of the pipelines with a minimum internal diameter of 50 mm shall be available for the purpose of killing the well. The other pipeline with a minimum internal diameter of 75mm shall be available for bleeding well fluid to the choke manifold.

(c) the choke manifold containing not less than two adjustable chokes, one of which shall be hydraulically controlled, connected to the choke line referred to in paragraph (b);

(d) a kill pump facility connected to the kill line referred to in paragraph (b); and

(e) a fill-up line.

(4) An inside blow-out preventer assembly (back pressure valve) and a full opening drill string safety valve in the open position shall be kept on the rig floor at all times whilst operations are in progress, with suitable crossover substitutes to enable installation on all drill pipe, drill collars and tubing in use.

(5) A kelly cock shall be installed immediately below the swivel and another at the bottom of the kelly, of such design that it can be run through the blow-out preventers.

(6) During operations there shall be a control panel for operating blow-out preventers and choke manifolds, located at such a distance from the drill floor as to ensure safe and ready access in an emergency.

(7) Each choke manifold shall have pressure gauges, clearly visible to the choke operator when standing in his normal operating position for either the remotely or hand adjustable chokes, which indicate -

(a) the drill pipe pressure at the drill floor; and

(b) the casing string/drill string annulus pressure at a known point upstream of the choke.

(8) Installed blowout prevention equipment must not be repaired or removed until reasonable steps are taken to ensure that the well is safe.

(9) The Director must be notified:

(a) whenever blowout prevention equipment is removed for any reason other than for routine operations; and

(b) whenever blowout prevention equipment is re-installed.

(10) A notification under Sub-Clause (9)(a) above must include the reason for the removal of the equipment and the steps taken to make the well safe.

509. Pressure Testing Blow-out Prevention Equipment

(1) After setting the blow-out preventer stack the pipe rams, the wellhead connection, and the choke and kill lines shall be tested to the maximum anticipated surface pressure, or such other pressure as may be approved and the annular type blow-out preventers shall be tested to 70% of their rated pressure or 70% of the test pressure for the pipe rams, whichever is less -

(i) when installed;

(ii) before drilling out of each casing string;

(iii) not less than weekly whilst drilling;

(iv) following repairs that require disconnecting a pressure seal in the assembly; and

(v) before perforating or production testing, unless a valid pressure test has occurred in the past 48 hours.

(2) The blind rams shall be function-tested at the times stipulated in Sub-Clause (1) provided that, after installing each casing string, they shall be pressure tested to a pressure not less than 70% of the burst pressure of the casing string just installed, or to their working pressure, or as provided in Sub-Clause (1), whichever is the least.

(3) The blow-out preventers shall be function-tested on each round trip but not more frequently than once per day with the exception of the annular type blow-out preventers where a weekly function test is required.

(4) In the event that a test indicates that equipment is not operating correctly, operations shall be discontinued until the deficiencies have been corrected and the equipment subjected to another test.

(5) The results of each blow-out preventer test shall be recorded in the driller's log and the daily drilling report.

510. Mud Monitoring System

Unless otherwise approved the following mud system monitoring equipment shall be installed and used during all drilling operations after setting and cementing the conductor casing string -

(a) a recording mud pit level indicator to determine mud pit volume gains and losses, including a visual and audio warning device;

(b) a mud volume measuring device for accurately determining the mud volumes required to fill the hole on trips;

(c) a mud return or full hole indicator to determine when returns have been obtained or when they occur unintentionally, as well as to determine that returns essentially equal the pump discharge rate;

(d) a pump stroke counter;

(e) a gas separator, gas knockout pot or a mud degasser; and

(f) a mud gas monitoring device to determine the concentration of gas in the drilling mud.

511. Penetration Rate and Formation Pressure Monitoring

A drilling rig, while engaged in drilling operations, must be fitted with equipment that provides a continuous recording of the penetration rate and can be used as a guide to warn against possible and approaching formation pressure increases.

512. Accumulators

(1) Accumulators shall be located a minimum of 15 metres away from the rig floor and, without accumulator pump assistance, shall have sufficient capacity at all times to -

(a) open or close the hydraulically operated choke line valve;

(b) close or open the annular type blow-out preventer; and

(c) close or open all blow-out preventer pipe rams.

(2) Accumulator pumps shall be capable of re-building fluid pressure in the accumulators within a period of three minutes to a sufficiently high level to -

(a) open the hydraulically operated choke line valve; and

(b) close the annular type blow-out preventer

(3) Accumulators shall be connected to the blow-out preventers with lines of working pressure at least equal to the working pressure of the accumulator and any lines located under the substructure shall be of steel construction unless completely sheathed with adequate fire resistant sleeving.

(4) Accumulator pumps shall have two independent sources of power.

513. Blow-out Prevention Drills

(1) Blow-out prevention drills shall be conducted weekly for each drilling crew to ensure that all equipment is operating and that crews are properly trained to carry out emergency duties.

(2) All blow-out prevention drills and response times shall be recorded in the driller's log and the daily drilling report.

(3) A notice on the rig floor, shall provide details of the well control procedures proposed to be followed in the event that indication of a well kick is observed and all drilling crews shall be trained in those procedures.

(4) All on-site personnel holding the position of driller (including any person who may temporarily stand in for the driller) or more senior shall attend, at least once every 24 months, an accredited well control school or refresher course in well-control and obtain a certificate of proficiency.

514. Formation Integrity Testing

(1) A formation integrity test shall be conducted after drilling out the casing shoe of surface and intermediate casing strings to establish that cementation and formation strength at the shoe are adequate to sustain the maximum anticipated pressures which may be imposed during subsequent drilling operations.

(2) Where a test requires that the approved drilling and casing program be amended, any such amendments shall be submitted to the Director for approval.

(3) Where formations are encountered below a casing shoe which require the use of drilling fluid densities not anticipated in the approved drilling program and which could result in excessive pressures being imposed at the casing shoe an additional formation integrity test shall be performed and, if the result differs from that performed at the casing shoe, the Director shall be notified forthwith and the casing program amended if necessary.

(4) All formation integrity test results shall be recorded in the driller's log and the daily drilling report.

515. Drilling Fluid

(1) The characteristics and use of the drilling fluid shall provide adequate control of any sub-surface pressures likely to be encountered.

(2) Wherever possible the well shall be maintained full of such drilling fluid.

(3) Sufficient reserves of drilling fluid and supplies of drilling fluid materials shall be available at the well site for immediate use to comply with Sub-Clauses (1) and (2).

(4) Tests consistent with API RP 13B-1 - "Recommended Practice for Field Testing Water-Based Drilling Fluids" and API RP 13B-2 - "Recommended Practice for Field Testing Oil-Based Drilling Fluids", as appropriate, shall be performed on a regular basis while drilling and the results recorded in the driller's log and the daily drilling report.

516. Deviation Surveys

(1) Unless otherwise approved, deviation surveys shall be taken at intervals of not more than 200 metres to ascertain the deviation of a well from vertical.

(2) A well shall not be directionally drilled without approval, except for a short distance to straighten a hole, sidetrack junk or correct other mechanical difficulties.

517. Conversion of Wells into Water Wells

(1) When, for the purpose of drilling a well a notice of intention to enter land is obtained, or a right of entry from an owner/occupier of land is given, the Operator shall raise with the owner/occupier the possibility of converting the well into a water well should the well not be capable of commercial petroleum production.

(2) The Operator shall furnish the Director with copies of any correspondence entered into under Sub-Clause (1).

(3) If it is decided to convert a well into a water well, the Operator shall furnish details of the proposed conversion to the Director for approval as soon as practicable after the decision is made.

518. Oil or Gas Lost or Used During Repair Operations

The quantities of all oil or gas lost by burning, venting to the atmosphere, flaring or mixing with other circulating fluids in the course of any well repair, recompletion or other similar operation shall be reported to the Director as soon as practicable after the relevant event.

519. Evaluation of an Occurrence of Petroleum

If the Director considers that an Operator is not adequately evaluating a potential occurrence of petroleum, he may require the Operator to carry out such coring, logging or testing operations as he thinks reasonable in the circumstances.

520. Core and Cutting Samples

(1) Where cuttings are recovered from a well a set of representative samples, each a minimum of 100g dry weight where practicable, shall be washed, dried in an approved manner and placed in suitable plastic bags or plastic bottles (obtainable from the Northern Territory Department of Resources Core Library) that are properly labelled for identification and lodged as required by the Director.

(2) Where whole cores are recovered they shall where practicable be slabbed vertically and at least one vertical quarter of the core shall be placed in suitable labelled container and lodged as in Sub- Clause (1).

(3) Full diameter core samples may, where approved, be retained for special studies provided that -

(a) they are retained in Australia unless otherwise approved and any skeletal material is returned to Australia within 12 months of the approval

(b) care is taken to protect them from unnecessary damage; and

(c) all residues are lodged with the Director on completion of the studies.

(4) Side-wall cores shall not be sent out of Australia unless otherwise approved, and all residues remaining after any studies on the cores shall be preserved and lodged with the Director.

(5) In relation to any samples retained overseas for further analysis, an annual report on progress shall be sent to the Director.

521. Reports on Analysis of Core and Cuttings

(1) Where an investigation, analysis or study is conducted on cuttings or cores, a copy of the report of the work and its conclusions shall be sent to the Director as soon as practicable after the completion of the work.

(2) Palynological, palaeontological and petrological slides prepared from cuttings or cores shall be properly stored and lodged with the Director when requested or in any event prior to the surrender, expiry or cancellation that part of the title to which the material relates.

522 .Age Dating of Samples

The Operator shall take all reasonable steps to ascertain, by palaeontological, radiometric or other suitable means, the ages of all rocks penetrated by a well.

523. Fluid Samples

(1) All formation fluid recovered from formation tests or non-routine production tests shall, as far as practicable, be sampled in accordance with API RP 44 - “Recommended Practice for Sampling Petroleum Reservoir Fluids”.

(2) Samples shall be labelled and analysed, and liquid samples shall be preserved for at least six months.

(3) Where available, a 1 litre sample of liquid hydrocarbons or other fluid from formation or production tests shall be sent to the Director upon request.

(4) Results obtained from the analysis of samples shall be furnished to the Director as soon as practicable after they are obtained.

524. Well Evaluation Logs

(1) Before a well is cased (other than with surface casing), completed, suspended or abandoned, an approved suite of logs shall be run and recorded.

(2) The suite shall at least be sufficient to provide a proper determination of -

(a) formation porosity;

(b) formation fluid saturations;

(c) stratigraphic correlation with surrounding wells; and

(d) if inadequate control exists in the vicinity of the well, velocity control.

(3) The following shall be furnished to the Director -

(a) a copy of each log run, which shall be forwarded as soon as possible after it is recorded;

(b) a copy of each log run data in standard format (ASCII or LAS), which shall be forwarded as soon as possible after it is recorded

525. Protection of Aquifers

All reasonable steps shall be taken during well or production operations to prevent communication between, leakage from or the pollution of aquifers that serve, or could serve, any useful purpose.

526. Production or Drill Stem Tests

(1) A person shall not conduct a production or drill stem test in an exploration, development or an appraisal well not yet producing without approval.

(2) An application for approval to conduct a production or drill stem test shall be accompanied by particulars of -

(a) the date and time of test;

(b) the equipment proposed to be used for the test;

(c) the proposed testing program;

(d) the proposed test intervals;

(e) the proposed duration;

(f) the maximum quantity of petroleum or water proposed to be produced; and

(g) the proposed method of disposal of the petroleum, water or gas produced.

(3) deleted

(4) The following conditions shall pertain to drill-stem tests or production tests.

(a) When production testing is to be performed in the vicinity of an inhabited area, all reasonable steps shall be taken to warn persons who could be affected, and the tests shall be conducted in a manner that minimizes the risk of injury or damage to property;

(b) All personnel shall be familiar with the relevant emergency procedures.

(c) All flowlines, valves and equipment used in a production test shall have a rated working pressure in excess of all anticipated pressures and, where appropriate, shall be tested prior to initial use at each well to at least those anticipated pressures.

(d) Open hole formation tests shall not be opened for flow during the hours of darkness except with the prior approval of the Director.

(e) Subject to Sub-Clause (f), if formation fluids are produced into the test string, they shall be reverse circulated from the test string before it is pulled from the hole.

(f) In a cased hole, formation fluids in the test string may be displaced back into the formation from which they were produced.

(g) During formation testing, or the removal of any pipe after a formation test, a competent person must remain at the rig and oversee the operation.

(h) During formation testing, all motors, engines and lights that are not required for the operation shall be shut off.

(i) During formation testing, the annular space of the well shall be kept full of drilling fluid of a density adequate to control formation pressure;

(j) Fluids brought to the surface during formation testing shall be safely disposed of through an independent test manifold and choke.

(k) Any choke equipment that forms part of the blow-out prevention equipment shall not be used for flow control during a formation test.

(l) If swivel joints or flexible hoses are used in the system during formation testing, they shall be equipped with wire rope or chain safety lines capable of containing any movement or whipping of the pipe or hose in the event of failure.

(m) All test strings shall be equipped with the means to reverse circulate out their contents.

(n) Well stimulation operations, such as swabbing or acidizing, shall not be initiated during the hours of darkness, or continued beyond the hours of daylight, without approval.

(5) If a drillstem test results in the discovery of a new pool of petroleum, the Operator shall notify the Director as soon as practicable after the discovery is made and furnish -

(a) a copy of the relevant operational reports;

(b) a legible copy of the pressure recorder chart for each test taken on the well; and

(c) an interpretation of those tests.

527. Flammable Vapours

All vessels and equipment from which flammable vapours may issue shall be safely vented to atmosphere, and any significant volume of gas that is vented shall be burnt through a flare system in accordance with this Schedule.

528. Approval to Abandon or Suspend a Well

(1) A well shall not be abandoned or suspended without prior approval, except as provided for in Sub-Clause (4).

(2) Subject to Sub-Clause (4), while drilling operations are being undertaken a well shall not be left in a condition which, in the opinion of the person-in-charge or the Director, is unsafe. Prior to the cessation of drilling operations, even temporarily, a well shall be made safe in accordance with good oilfield practice.

(3) Subject to Sub-Clause (4), where casing is being installed, if a well encounters or has encountered -

(a) hydrocarbons;

(b) abnormally pressured water;

(c) unstable coals or shales; or

(d) lost returns;

the drilling operations shall be continued to the next scheduled casing point at which point the hole will be logged, cased and secured at the surface.

(4) In the event of an emergency or adverse weather conditions requiring, in the opinion of the person-in-charge or the Director, cessation of drilling operations, the well shall be made safe in accordance with good oilfield practice.

(5) An application for approval to abandon or suspend a well shall give particulars of:

(a) the reason for abandonment or suspension;

(b) the proposed abandonment or suspension program including the method by which the well will be made safe; and

(c) such further information as the Director may require.

529. Abandonment of a Well

Well abandonment shall comply with the following.

(1) In uncased hole, cement plugs shall be placed such as to provide a minimum of 30 metres of cement above and a minimum of 30 metres of cement below any significant oil, gas or fresh water zones.

(2) Where there is open hole immediately below the casing string, there shall be placed in that casing string -

(a) a cement plug placed by displacement method so as to extend at least 30 metres above and at least 30 metres below the casing shoe; or

(b) a cement retainer with effective back pressure control set at least 10 metres, but not more than 30 metres, above the casing shoe with a cement plug calculated to extend at least 30 metres below the casing shoe and at least 15m above the retainer; or

(c) where lost circulation conditions exist or are anticipated, a permanent type bridge plug set within 45 metres above the casing shoe with at least 15m of cement on top of the bridge plug.

(3) If the casing string is cut and recovered, a cement plug shall be placed to extend at least 30 metres above and at least 30 metres below the cut end of the casing string, and a retainer may be used in setting the required plug.

(4) Where the casing string has been perforated-

(a) a cement plug shall be placed opposite the perforations to extend from at least 30 metres below to 30 metres above the perforated interval; or

(b) the perforated interval may be plugged by means of a cement retainer set in the casing string no more than 45m above the top of the perforated interval with a cement plug extending at least 15m above the retainer, provided the perforated interval is isolated from open hole below; or

(c) subject to Sub-Clause (b) where a succession of retainers is used to isolate a series of perforated test intervals, only the topmost retainer need have a minimum of 15m of cement plug placed above it.

(5) In a cased hole containing a liner string or strings, a cement plug, of at least 30 metres height, shall be placed immediately above each liner hanger.

(6) A surface cement plug extending at least 15m below the surface shall be placed in the innermost string of casing that extends to the surface.

(7) Any annular space that extends to the surface, and which is open to drilled hole, shall be plugged with sufficient cement to fill at least 30 metres of the annular space.

(8) The location and integrity of cement plugs placed in accordance with Sub-Clauses (2), (3), (4) and (5) shall be verified by the application of weight, or other methods as approved.

(9) Any intervals of cased hole between cement plugs shall be filled with fluid that is of an appropriate density and suitably inhibited to prevent corrosion of the casing.

(10) Blow-out preventers shall not be removed until all plugs required to isolate the open hole have been set and their location and integrity satisfactorily determined.

(11) No casing may be recovered if its recovery would expose any abnormal pressure, lost circulation, petroleum or water zone.

(12) At least two metres above ground level, a steel plate shall be installed, welded to a suitable steel post in turn welded to the casing head or outermost casing stub, with well name, number and total depth bead-welded to it.

530. Well Completion

(1) The surface and subsurface equipment of a completed well shall (where applicable) be arranged to permit the measurement of the pressure and temperature at the wellhead and at the bottom of the hole (closed in or flowing), and to permit any other generally recognized test to be carried out.

(2) The surface equipment shall be fitted with sampling connections.

(3) The Operator shall, on completion and any recompletion of a well, keep and make readily available to an Inspector an accurate record of all subsurface equipment and junk in the well.

(4) Before opening a well to production and after every major repair, recompletion or workover, the wellhead and flow line connection shall be pressure tested.

531. Disposal of Produced Oil and Gas

(1) Any oil or gas that is circulated out of or produced from a well during a drilling, testing or repair operation, and that is not flowed through the well's flowline to a gathering facility, shall be flowed through an appropriate manifold and properly staked temporary flow line to a storage tank or flare.

(2) Clean up operations and tests that use temporary well site facilities shall be commenced during daylight hours.

(3) If petroleum is flowed to a flare it shall be kept, as far as possible, continuously alight.

532. Restoration of Site

As far as possible a well site area shall be restored to its former condition and if any part of a wellhead is left above ground level, the well shall be adequately fenced. Mousehole and rathole shall be plugged at surface.

FUGITIVE EMISSIONS

526. Production or Drill Stem Tests

(1) A person shall not conduct a production or drill stem test in an exploration, development or an appraisal well not yet producing without approval.

(2) An application for approval to conduct a production or drill stem test shall be accompanied by particulars of -

(a) the date and time of test;

(b) the equipment proposed to be used for the test;

(c) the proposed testing program;

(d) the proposed test intervals;

(e) the proposed duration;

(f) the maximum quantity of petroleum or water proposed to be produced; and

(g) the proposed method of disposal of the petroleum, water or gas produced.

(3) deleted

(4) The following conditions shall pertain to drill-stem tests or production tests.

(a) When production testing is to be performed in the vicinity of an inhabited area, all reasonable steps shall be taken to warn persons who could be affected, and the tests shall be conducted in a manner that minimizes the risk of injury or damage to property;

(b) All personnel shall be familiar with the relevant emergency procedures.

(c) All flowlines, valves and equipment used in a production test shall have a rated working pressure in excess of all anticipated pressures and, where appropriate, shall be tested prior to initial use at each well to at least those anticipated pressures.

(d) Open hole formation tests shall not be opened for flow during the hours of darkness except with the prior approval of the Director.

(e) Subject to Sub-Clause (f), if formation fluids are produced into the test string, they shall be reverse circulated from the test string before it is pulled from the hole.

(f) In a cased hole, formation fluids in the test string may be displaced back into the formation from which they were produced.

(g) During formation testing, or the removal of any pipe after a formation test, a competent person must remain at the rig and oversee the operation.

(h) During formation testing, all motors, engines and lights that are not required for the operation shall be shut off.

(i) During formation testing, the annular space of the well shall be kept full of drilling fluid of a density adequate to control formation pressure;

(j) Fluids brought to the surface during formation testing shall be safely disposed of through an independent test manifold and choke.

(k) Any choke equipment that forms part of the blow-out prevention equipment shall not be used for flow control during a formation test.

(l) If swivel joints or flexible hoses are used in the system during formation testing, they shall be equipped with wire rope or chain safety lines capable of containing any movement or whipping of the pipe or hose in the event of failure.

(m) All test strings shall be equipped with the means to reverse circulate out their contents.

(n) Well stimulation operations, such as swabbing or acidizing, shall not be initiated during the hours of darkness, or continued beyond the hours of daylight, without approval.

(5) If a drillstem test results in the discovery of a new pool of petroleum, the Operator shall notify the Director as soon as practicable after the discovery is made and furnish -

(a) a copy of the relevant operational reports;

(b) a legible copy of the pressure recorder chart for each test taken on the well; and

(c) an interpretation of those tests.

527. Flammable Vapours

All vessels and equipment from which flammable vapours may issue shall be safely vented to atmosphere, and any significant volume of gas that is vented shall be burnt through a flare system in accordance with this Schedule.

531. Disposal of Produced Oil and Gas

(1) Any oil or gas that is circulated out of or produced from a well during a drilling, testing or repair operation, and that is not flowed through the well's flowline to a gathering facility, shall be flowed through an appropriate manifold and properly staked temporary flow line to a storage tank or flare.

(2) Clean up operations and tests that use temporary well site facilities shall be commenced during daylight hours.

(3) If petroleum is flowed to a flare it shall be kept, as far as possible, continuously alight.

540. Swabbing

(1) While swabbing operations are being carried out all engines, motors and other possible sources of ignition that are not essential to the operation shall be shut down.

(2) During swabbing operations, the swabbing line shall be packed off at the surface so that fluids are directed as much as possible through a closed flow system.

(3) During swabbing operations produced fluids shall be piped directly to a production facility, flare pit or tank.

(4) As noted in Sub-Clause 526 (4) (n) swabbing operations shall not be initiated during the hours of darkness, nor continued beyond the hours of daylight, without approval.

619. Approval to Vent or Flare

Except in an emergency, petroleum shall not be flared or vented without approval, either directly or as part of an approved operation or plan.

Division 4 - Reporting

284. Reporting of Death and Serious Injury

(1) In this Clause and this Schedule a serious injury is one which requires immediate attention by a medical practitioner.

(2) Where a person dies or suffers a serious injury -

(a) a report shall forthwith be made to an Inspector; and

(b) a report in writing giving full particulars and all related circumstances shall be transmitted to the Director as soon as practicable after the occurrence.

(c) the above reports shall be in addition to, and not take precedence over, reports required by NT WorkSafe.

286. Reporting Serious Damage

(1) In this Clause and this Schedule serious damage to property means

(a) the loss or destruction of property with a value exceeding $50,000;

(b) damage to property, the repair of which damage would cost an amount exceeding $50,000; or

(c) a loss, destruction or damage to any property by reason of which any person dies or suffers serious injury.

(2) Where serious damage to property occurs -

(a) a report of each occurrence shall forthwith be made to an Inspector; and

(b) a report in writing shall be submitted to the Director as soon as practicable specifying -

(i) the date, time and place of such occurrence;

(ii) particulars of the damage;

(iii) the events so far as they are known or suspected that caused or contributed to the occurrence;

(iv) particulars of repairs carried out or proposed to be carried out to damaged property; and

(v) measures taken, or to be taken, to prevent a possible recurrence.

287. Reporting a Potentially Hazardous Event

Where an event occurs which is not in the normal or ordinary course of a particular operation and which is professionally considered to have been likely to cause injury to a person or serious damage to property -

(a) a report of the event shall forthwith be made to an Inspector; and

(b) a report in writing of the event shall be submitted to the Director as soon as practicable specifying measures taken or to be taken to prevent a possible recurrence.

288. Reporting Damage Less Than $50,000

Where damage to property occurs which is not serious damage to property but which results in a significant loss of structural integrity or load bearing capacity in the property damaged or results in some other significant unsafe condition -

(a) a report of the damage shall forthwith be made to an Inspector; and

(b) a report in writing shall be submitted to the Director as soon as practicable specifying measures taken or to be taken to prevent a possible recurrence.

289. Reporting Escape or Ignition of Petroleum and Other Material

(1) A report shall forthwith be made to an Inspector upon the occurrence of -

(a) a significant spillage of hydrocarbons which in areas of inland waters is in excess of 80 litres, in other areas is in excess of 300 litres and if in gaseous form is in excess of 500 m3; or

(b) any uncontrolled escape or ignition of petroleum or any other flammable or combustible material causing a potentially hazardous situation.

(2) In the event of any occurrence referred to in Sub-Clause (1) a report in writing shall be submitted to the Director as soon as practicable specifying -

(a) the date, time and place of the occurrence;

(b) the estimated quantity of liquid that escaped or burned;

(c) particulars of any damage caused;

(d) the events so far as they are known or suspected to have caused or contributed to the escape or ignition;

(e) particulars of methods used to control the escape or ignition;

(f) particulars of methods used or proposed to be used to repair property damaged; and

(g) measures taken, or to be taken, to prevent a possible recurrence.

290. Reporting of Emergencies

Any emergency shall be reported forthwith to an Inspector.

Attachment D – Guidelines and other documents

Contents

1. Guideline on the Petroleum Exploration Permit Application Process

PETROLEUM EXPLORATION PERMIT

PERMIT APPLICATION, PERMIT CONDITIONS AND PERMIT ADMINISTRATION

A guideline in relation to the

Petroleum Act

(As in force at 1 August 2013)

For further information, please contact:

In person	Petroleum Registrar Energy Directorate NT Department of Mines and Energy 4th Floor, Centrepoint Building, The Mall, Darwin NT 0800
By post	Attention - Petroleum Registrar Energy Directorate NT Department of Mines and Energy GPO Box 4550 Darwin NT 0801
By fax	+61 8 8999 5191 – Attention: Petroleum Registrar
By phone	+61 8 8999 5396 – Petroleum Registrar
By e-mail	Petroleumoperations@nt.gov.au – Petroleum Registrar

Contents

Introduction

The purpose of these guidelines is to assist and inform industry of the statutory obligations, processes and expectations in relation to petroleum exploration permits (*permit*) under the Northern Territory *Petroleum Act* (the *Act*) that applicants will need to observe when preparing an application for a permit. The guidelines also describe post application and post grant requirements and processes with respect to this title type.

Whilst the guidelines have been provided to assist applicants in their compliance with the Act, it is incumbent on each applicant to acquaint themselves with the provisions of the Act and all other laws of the Northern Territory (NT) as are applicable. Although these guidelines are here to assist you, in all cases the legislation prevails.

The Department's over-arching objective is to manage the NT's petroleum resources and acreage in a manner consistent with the long-term viability of the industry and best return for the Territory.

Within that framework, the basic objective in awarding a permit is to enable the efficient discovery and evaluation of any petroleum resources in the area, for eventual production under licence. Consistent with the Act, applications for a permit will be dealt with on their merits.

[*The guidelines will be amended from time to time to reflect current practices and or legislation and are available online* Energy Titles and Operations Forms and Guidelines.]

Purpose of Title

A permit, while it remains in force, gives the holder, subject to the Act and in accordance with the conditions to which the permit is subject and the directions, if any, the exclusive right to explore for petroleum, and to carry on such operations and execute such works as are necessary within the permit area; i.e. drill, survey for, but not produce, hydrocarbons.

Pre-requisites

The common essential pre-requisites for an application are:

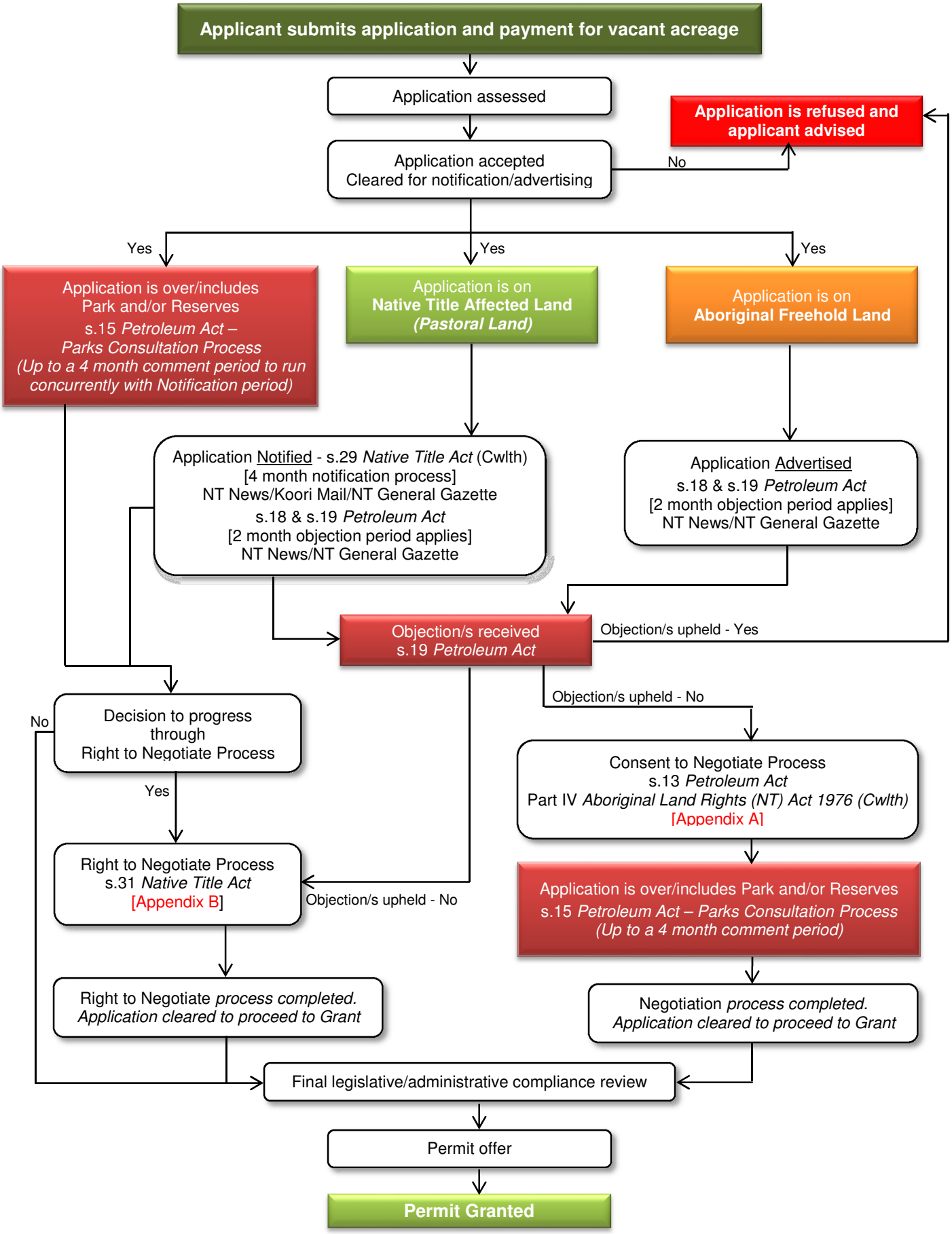
- the land is available
  (see “Land Availability” section of these guidelines);
- a realistic exploration program is proposed; and
- that the applicant
  - has the financial and technical resources to undertake their proposed program; and
  - has complied with the Act in respect of making a valid application.

Other Legislation

If an application attracts the Right to Negotiate process under the Commonwealth *Native Title Act 1993*, the relevant procedures under that Act must be complied with.

The Commonwealth *Aboriginal Land Rights (NT) Act 1976* will apply for applications over Aboriginal Freehold Land.

Exploration Permit Application Process



Land Availability

Current Title Maps
The Department maintains an electronic spatial database for the recording and maintenance of Petroleum Title information. The Title Information System (TIS) provides an online public access to this database. TIS depicts areas currently held or sought by explorers and those which are reserved from exploration.

In order to determine areas that are available or that are likely to become available, through TIS a dynamic map of the Territory can be viewed and current information printed.

Registered users can access queries and textual information on all current titles. Registration is free and application forms can be printed from www.minerals.nt.gov.au .

Conflicting Tenure
Permit applications cannot be made over land that is currently the subject of a Reservation of Blocks under Section 9 of the *Petroleum Act* nor the subject of other petroleum tenure or application.

Land Status

There are three (3) main categories of land tenure in the NT, which determines the grant process of an application:

- Freehold Land;
- Aboriginal Freehold Land; and
- Native Title Affected Land.

It is a policy of the Department to split applications that are/may be over more than one type of land tenure. However, Freehold land and Native Title affected land can be grouped in one application.

Note: Applications that cover both Aboriginal Freehold Land and land that may be affected by Native Title cannot be accepted. Applicants will be requested to split such applications into single landforms to allow processing under the appropriate Act.

Freehold Land
Freehold land title, sometimes referred to as a Grant in Fee Simple or Estate in Fee Simple, means that the Crown (or Government) has passed all interest in the land, other than resources, onto the owner. An example of freehold land is the average house block in a city or town.

Aboriginal Freehold Land (ABF)
Sections 12 and 13 of the *Act* govern the procedures for application, negotiation and grant of a permit over Aboriginal land. [Appendix A]

Aboriginal land is defined in Section 5(1) of the Act by reference to the *Aboriginal Land Rights (NT) Act 1976* (**ALRA**) of the Commonwealth, which defines it as:

- land held by a Land Trust for an estate in fee simple; or
- land the subject of a deed of grant held in escrow by a Land Council.

Land Councils (established under Section 21 of ALRA) are responsible for the Aboriginals living within their area boundary. Accordingly, where an application crosses the boundary between the Land Councils we will require the application to be split, so that each area can be dealt with independently by the Land Council with the appropriate authority.

N.B. An applicant may only enter into negotiations with the Land Council for consent to the grant of a permit in relation to Aboriginal Land after first having lodged an application for the grant of a permit and receiving the consent of the Minister for Mines and Energy to enter into negotiations under Section 13 of the *Petroleum Act*.

The consent of the Minister gives the applicant the exclusive right to enter into negotiations with the relevant Land Council.

Native Title Affected Land
An application for a permit on Pastoral Lease land may be subject to the *Native Title* Act (NTA) *1993*. Applications are advertised under the NTA *Right to Negotiate Procedure (RTN)*. The RTN process is used for all petroleum negotiations on Native Title affected land. [Appendix B]

The RTN public notification period of four (4) months allows the Native Title Claimants to register and if required, to lodge an objection with the National Native Title Tribunal (NNTT).

The NT Government, through the Department of Mines and Energy, Mineral Titles Division, case manages applications through the RTN procedure.

The NTA requires that negotiations be carried out "in good faith". The Department of Mines and Energy has an expectation that negotiations to reach an agreement take place within firm timeframes. (*Refer 'Timeframes for the Right to Negotiate Process for Title Applications on Native Title Affected Land').*

Northern Territory National Parks
Permits may be granted over land in a NT declared park, reserve or wilderness zone only after a consultation process between this Department and the Minister administering the *Territory Parks and Wildlife Conservation Act* has been completed.

If the Permit is granted as a result of this process, it may be subject to stringent conditions agreed to between the appropriate Ministers.

Telecommunication Sites and Defence Facilities
It is the practice of the Department to exclude any Telecommunication Sites or Commonwealth Land from the grant of a permit.

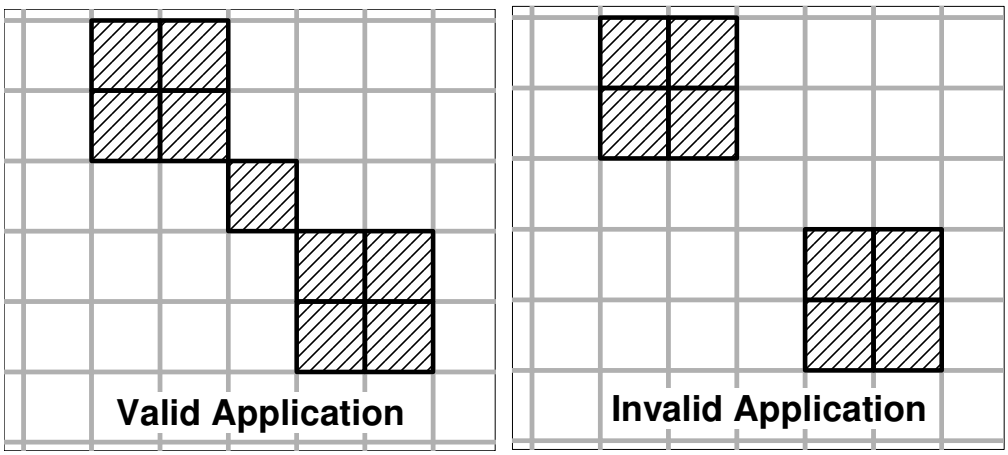
Graticular Sections/Blocks

The NT is divided up into a series of 1:1 000 000 Map sheets. Each map sheet is 4 degrees of latitude by 6 degrees of longitude and has a common name e.g. Darwin, and index name SD52.

The NT is also divided into graticular blocks. Each block is five minutes of latitude by five minutes of longitude. These graticules are used for all petroleum titles. There are 3456 five-minute blocks (numbered 1 to 3456) on each 1:1,000,000 map sheet. The blocks are defined on the **Australian Geodetic Datum 1966, (AGD66)**.

Each block has an average area of approximately 80 sq kms; blocks to the north of NT have an area of about 83 sq kms, while blocks to the south have an area of about 78 sq kms. The difference is bought about by the convergence of meridians of longitude between the Equator and the South Pole.

Discrete Areas
An application can only be made over one discrete area. A discrete area can be a single block, or a number of blocks that are joined by a side or a point. Applications made over two or more discrete areas cannot be accepted.



Application for a Permit

Applicants need to refer to Section 16 of the Act when making application for a permit. (Please note that all applicants are required to identify themselves).

- **Full name of applicant/s** - In case of individuals, please state full name of each person. In the case of corporations, state name of each corporation as shown on their latest Certificate of Incorporation;
- **Australian Company Number** (ACN or the ARBN where the applicant is a foreign company) – This is the number described on the Certificate of Incorporation issued by the Australian Securities and Investment Commission;
- **Principal or residential address** - Please state each applicant's principal or residential address. This is the physical address at which documents will be served on each applicant;
- **Postal Address** - Please state postal address of each applicant;
- **Interest** - Where the application is made by two (2) or more persons the proposed sharing arrangements between the applicants;
- **Schedule of blocks** being described by reference to the name/s of a map sheet/s (e.g. Darwin SD52) of the 1:1,000,000 Series and the number of graticular sections shown thereon;
    - *Maximum number of blocks/part blocks for which an application may be made is 200,*
- **A map** clearly delineating application area and boundaries of existing permit or licence areas in the immediate vicinity of application area;
- **Applicant's assessment** of the petroleum potential of area, including a geological and geophysical review and technical assessment, and concepts underlying the proposed exploration program;
- **Proposed technical works program** for exploration of the blocks during each year of the term of the proposed permit and must show an aggressive exploration program;
- **Evidence of the technical and financial capacity** of the applicant/s to carry out the proposed technical works program and to comply with the requirements of the Act.
    - Applicants should list the professional staff proposed to be used in the program, together with a short resume of their past record of proven technical experience.
    - Normally, applicants are expected to have at least sufficient net current assets to complete the first two years' program and to provide reasonable assurance that further funds will be forthcoming. If the applicant is a publicly listed company the last issued annual company report or the relevant sections thereof and the last issued quarterly report to the Stock Exchange should be included; and
    - If the applicant is not a public company, a report should be furnished giving the same information as would be furnished in the annual report of a public company, and in the latest quarterly stock exchange report.

  In either case a statement of financial commitments other than those proposed in the application, and any additional source of finance should be included. This statement should include a list of interests in petroleum tenements in other states of Australia.
- **The name of the designated operator** and evidence of the technical capacity of the operator to carry out the proposed technical works program and a single address for service of notices in respect of the application;
- **Past performance** of the applicant/s;
- **Prescribed application fee** - non-refundable, payable to *Receiver of Territory Monies (RTM)*; and
- Such other information in support of the application as the applicant thinks fit.

Criteria for Assessment of a Permit

Assessment Criteria
The Territory's aim is for aggressive exploration in the area to both establish and extract a reserve or to relinquish the area.

The Act calls (inter alia) for evidence of technical and financial capacity and a proposed work program while applicants may also submit any other supporting information.

A person may apply for a permit over any onshore area not already under permit or application. The following criteria (not necessarily in order of importance) will be considered:

- any objections received under section 19 of the Act and the applicant's responses;
- the prospectivity of the area and market demand for the acreage;
- the strength and timing of the work program;
- the extent to which the program addresses the whole permit area;
- the technical capacity of the applicant;
- the financial capacity of the applicant to commence and complete the proposed program (normally, applicants are expected to have at least sufficient net current assets to complete the first two years' program and to provide reasonable assurance that further funds will be forthcoming);
- the past performance of the applicant;
- the desirability of diversifying exploration (and eventual petroleum production) activity;
- any other information provided by the applicant;
- any other information considered relevant by the NT.

Post Application Requirements

Advertising
The Department will, as soon as practicable after an application is received (and subject to the assessment of an application), arrange to have a notice of the application published in the applicable newspaper/s and Gazette at the expense of the applicant/s. An invoice will be forwarded to the applicant/s following advertising. The advertising requirements are subject to the Act and the underlying tenure of the application area, i.e. Pastoral Lease or Aboriginal Freehold Land.

Permit Conditions

After consideration of a permit application, the Minister may grant the permit over all or part of the area sought and subject to such conditions as he sees fit. The proposed conditions will be discussed with the applicant prior to the formal offer.

Although requests for permit variation will be considered, permittees will be expected to complete the committed work programs lodged at time of application. The first three (3) years are less negotiable.

Applicants should note that summary work programs relating to a permit will be publicly available once the title is granted.

If a permit is required to go to the NNTT for an arbitral body determination, then the grant may also be subject to certain conditions to be complied by any of the parties.

Permits granted over land in a declared National Park, reserve or wilderness zone will require special conditions. The condition/s will be determined following the conclusion of the consultation process between this Department and the Minister administering the *Territory Parks and Wildlife Conservation Act*.

Security

Before granting a permit the Minister will require a security to be lodged for compliance with Act and to secure the applicant's compliance with the conditions to which the grant is made (Section 79). This security is currently set at *$10,000* per permit.

Security payments can be in the form of cash, credit card, cheque, money order, letter of Credit or Bank Guarantee.

Bank guarantees must be made out in favour of the Minister for Mines and Energy, money orders and cheques are to be made payable to the RTM and may be lodged by mail.

Direct Debit may be made by contacting the Energy Titles Unit on +61 8 8999 5263 for the Department's account details.

Other types of securities may be lodged at the Titles Front Counter from 8:00 am to 4:00 pm Monday to Friday, 5th Floor Centrepoint Building, Smith Street Mall, Darwin.

Post Grant Requirements

Annual Reports
In accordance with Section 59 of the Act annual reports are required within 28 days after the expiration of each period of 12 months.

The Minister may approve the lodgement of a late annual report; however the request to do so must be in writing.

A report shall include:

- Geological, geochemical and geophysical survey reports;
- Drilling and other work reports;
- Data, maps, logs and records in support of, or necessary to interpret, reports referred to in (a) and (b); and
- Expenditure and financial reports.

Permit Suspension / Extension / Waiver / Variation
Section 28 of the Act regulates the variation of conditions of a permit.

An application to suspend, extend, waiver or vary permit conditions is required to be submitted within three (3) months prior to expiry of the current work program year. Applications are considered on a *case by case* basis; however the first three (3) years of a work program must be satisfied.

Where a Permittee holds a number of permits, each permit is to be considered as a separate entity; applications will not be considered if submitted as a "group" for a number of permits.

- **Suspension/Extension** - Genuine *force majeure* circumstances will be considered as sufficient justification for a permit suspension, extension. *Force majeure* refers to an event of effect that cannot be reasonably anticipated or controlled via experience or care. Commercial circumstances that are common risks in the industry would not normally be considered as a basis for *force majeure* (e.g. changes in oil prices, difficulty in attracting farm-ins, increase drilling or survey costs).
  During suspension the Department will require regular reporting on progress for recommencement of activities. Suspensions and extensions, normally, do not exceed one year.
- **Variations** - Work programs may be accelerated at any time, and this does not require the approval of the department.
  All variations are subject to the discretion of the Department on a *case by case* basis. Work programs may not be varied to reduce or substitute the overall work program. Work may be deferred within a period provided the program is not reduced.
  Increased costs for one year do not allow the removal of an activity of the next year.

Permittees may seek to have an alternative work activity credited as meeting a work program commitment. In general, wells will not be permitted to be substituted by other work (e.g. seismic). If insufficient seismic has not been carried out to locate a well or prospect, it will be expected that the Permittee will undertake additional seismic activity and apply to the Department to defer the well. Activities that are designed to locate a prospect may be substituted, provided the Department is satisfied that the alternative work activity is technically robust and will meet or exceed the objective of the original work commitment.

Permit Renewal

An application for renewal of a permit is required to be submitted to the Minister *not earlier than six (6) months, but not later than three (3) months* before the expiration of the permit. Section 23 to Section 25 of the Act regulates the renewal of a permit. The Minister may not renew a permit more than twice.

A renewal application should include, but not be limited to:

- **The name and address** of the designated Permittee/Operator each Permittee including the participating interest in percentage of each Permittee.
- **A comprehensive report** of the previous work commitment program, findings and results.
- **The proposed minimum work program** for each of the five years of the renewal term should not contain any contingency work. Details of the specific number of wells to be drilled, line or square kilometres of seismic surveys, and the estimated expenditure in Australian dollars.

  Survey details are to be expressed in the following terms: 100 km new 2D Seismic Survey.
- **The technical qualifications** of the Permittee and of its employees evidencing the applicant's ability to undertake the proposed work.
- **A map and list of the 1:1,000,000 map sheet** block numbers to which the renewal application applies and a further map and list of the block numbers to be relinquished.

  Refer to Section 24 and 24A of the Act with regards to the requirement of reducing blocks at time of renewal.
- **Assessment** of the petroleum potential of area, including a geological and geophysical review and technical assessment, concepts underlying the proposed exploration program; and an outline of the exploration philosophy of the Permittee.
- **Prescribed application fee** - non-refundable, payable to the RTM; and.
- **Any additional information** the Permittee wishes to be taken into account on consideration of its renewal application.

Permit Operations/Activities

Operations or activities under a permit usually consist of geophysical surveys (seismic, gravity etc.) and the drilling of wells. All Energy titles are subject to conditions, which require the titleholder to obtain Departmental approval prior to the commencement of any field operation/activity. Approvals will be subject to the lodgement of an additional rehabilitation security.

The security will be required as a condition for the purpose of securing the payment of costs and expenses in relation to the Minister causing an action to be taken to prevent, minimise or rectify environmental harm, or to complete rehabilitation of a site/survey etc.

Departmental policy is that 100% of the cost for rehabilitation of disturbances is required as a security. Information regarding the security policy, calculation and cost estimates used by the Department can be made available by contacting the Energy Operations Unit on +61 8 8999 5460

Northern Territory Legislation

Northern Territory legislation is available for perusal at:

http://www.nt.gov.au/d/Minerals_Energy/index.cfm?header=Legislation

Appendix A - *Consent to Negotiate Process*

Read in conjunction with the "Exploration on the Aboriginal Freehold Land" Fact sheet & the *Aboriginal Land Rights (Northern Territory) Act (ALRA) 1976*

Exploration Licence or Permit Application
Lodged with the Department

Consent to Negotiate
NT Minister for Mines and Energy may issue consent to negotiate s41 ALRA

Consent Issued (3 months)

"Exploration Application"
Lodge an application with the relevant Land Council within three months of the date the consent to negotiate was issued. Application to comply with s41(6) ALRA

Application accepted by Land Council

Standard Negotiation Period (22 months)

- Parties consult to progress negotiations to reach an agreement and to the consent to the grant of the Exploration Licence or permit;
- During this process, the Land Council and the applicant will attend meetings with the Traditional Owners for the purpose of explaining and discussing the proposed exploration activities as required by s42 ALRA;
- There is a provision for mutually agreed extensions.

Outcomes of s42 Meeting

Refuse consent to the grant
Refusal of further negotiations

Moratorium
Exploration Licence or permit application is placed in moratorium for five (5) years. s48 ALRA

Negotiations Re-commence
Traditional Owners may recommence negotiations through their representative body at any time during this five (5) year period.

End of Moratorium
The applicant must lodge a new exploration application with the relevant Land Council within 30 days of the moratorium end date.

Consent to further negotiations

Consent to Negotiate for the Grant
Traditional Owners consent to further negotiations to formalise an agreement with the applicant. The relevant Land Council approves consent to grant

Federal Minister Approves consent to grant
Consent to grant given by Federal Minister for Families, Housing Community Services and Indigenous Affairs (FaHCSIA)

Agreement/Deed
Agreement/Deed provided to Department to progress Exploration Licence or permit Application to grant

Grant
Department grants exploration licence or permit in accordance with the *Mineral Titles Act* (2010) or *Petroleum Act*

Appendix A - *Exploration on Aboriginal Freehold Land*

Introduction

The two main categories of land tenure in the Northern Territory (NT), excluding townships, are Aboriginal Freehold (ABF) and Pastoral Lease.

When exploring on a Pastoral Lease, exploration licence (ELA) (*Mineral Titles Act (2010)*) or exploration permit (EPA) (*Petroleum Act*) applications may be subject to the *Native Title Act*. When exploring on ABF, ELA's and EPA's are subject to the *Aboriginal Land Rights (Northern Territory) Act 1976* (ALRA) process.

Under ALRA, Land Councils represent the traditional owners. There are four Land Councils in the NT; Northern Land Council, Central Land Council, Tiwi Land Council and the Anindilyakwa Land Council.

Below is a summary of the legislative frameworks and processes for ELA's and EPA's on ABF.


Exploring on-country

The *Mineral Titles Act* (MTA) / *Petroleum Act* (PA) Process

Exploration Licence and Exploration Permit applications (and subsequent mining leases (MTA)) on ABF are required to comply with the *MTA* or *PA*.

A requirement of ALRA is that an applicant seeking to explore on ABF must initially apply for an Exploration Permit or Exploration Licence.

ELA's must be made through the Mineral Titles Division and EPA s through the Energy Directorate, Department of Mines and Energy. Guidelines and application forms are available on the Department's internet site.

Following receipt of an ELA or EPA the Department ensures legislative compliance, and a public notification process is undertaken.

On completion of this process the NT Minister for Mines and Energy, may issue *consent to negotiate*. This consent then activates processes under Part IV of ALRA.

The ALRA Process

Following *consent to negotiate*, the applicant is required to lodge an "exploration application" with the relevant Land Council, within three months of the date of consent. 'Exploration applications" must contain details of proposed exploration activities, methods of extraction and treatment of any commodity that may be discovered, as required by s41(6) ALRA. Guidelines on preparing "exploration applications" are available from the relevant Land Councils.

When the "exploration application" is received and accepted by the Land Council, the parties consult

to progress negotiations in order to reach an agreement and to consent to the grant of the ELA or EPA.

During this process the Land Council and the applicant will attend meetings with the traditional owners for the purpose of explaining and discussing the proposed exploration activities under s42 of ALRA.

"on-country" meeting (s42)

Negotiating Timeframes

Under ALRA, negotiation towards agreement is to be carried out within prescribed timeframes.

The standard negotiation period of 22 months commences when the "exploration application" outlining exploration activities is accepted by the respective Land Council. The standard negotiation period expiry is calculated as ending 22 months from 1 January following the date of receipt of the "exploration application". If an agreement is not reached within the initial standard negotiating period (22 months), there is provision for an extension by mutual agreement.

Reaching Agreement

Once agreement is reached between the Land Council and the applicant, it is also a requirement of ALRA that consent to grant be given by the Federal Minister for Families, Housing Community Services and Indigenous Affairs (FaHCSIA).

Following this consent, the application is submitted to the Department of Mines and Energy to progress the ELA or EPA to grant. Upon grant of the ELA or EPA the Department of Mines and Energy administers the title in accordance with the *MTA* or *PA.*

Native Title & Aboriginal Land Rights Unit

Members of the Native Title and Aboriginal Land Rights Unit (NTALR Unit) attend (s42) meetings and are available to provide guidance on how best to present your "exploration application" at an on-country meeting.

If you have any queries about the process, the "exploration application" or any other requirements contact the NTALR Unit for assistance.

Contact Details

Native Title and Aboriginal Land Rights Unit

Tel: +61 8 8999 5322
Fax: +61 8 8981 7106
Email: ntalrunit@nt.gov.au
Web: www.minerals.nt.gov.au
TIS: www.minerals.nt.gov.au/tis

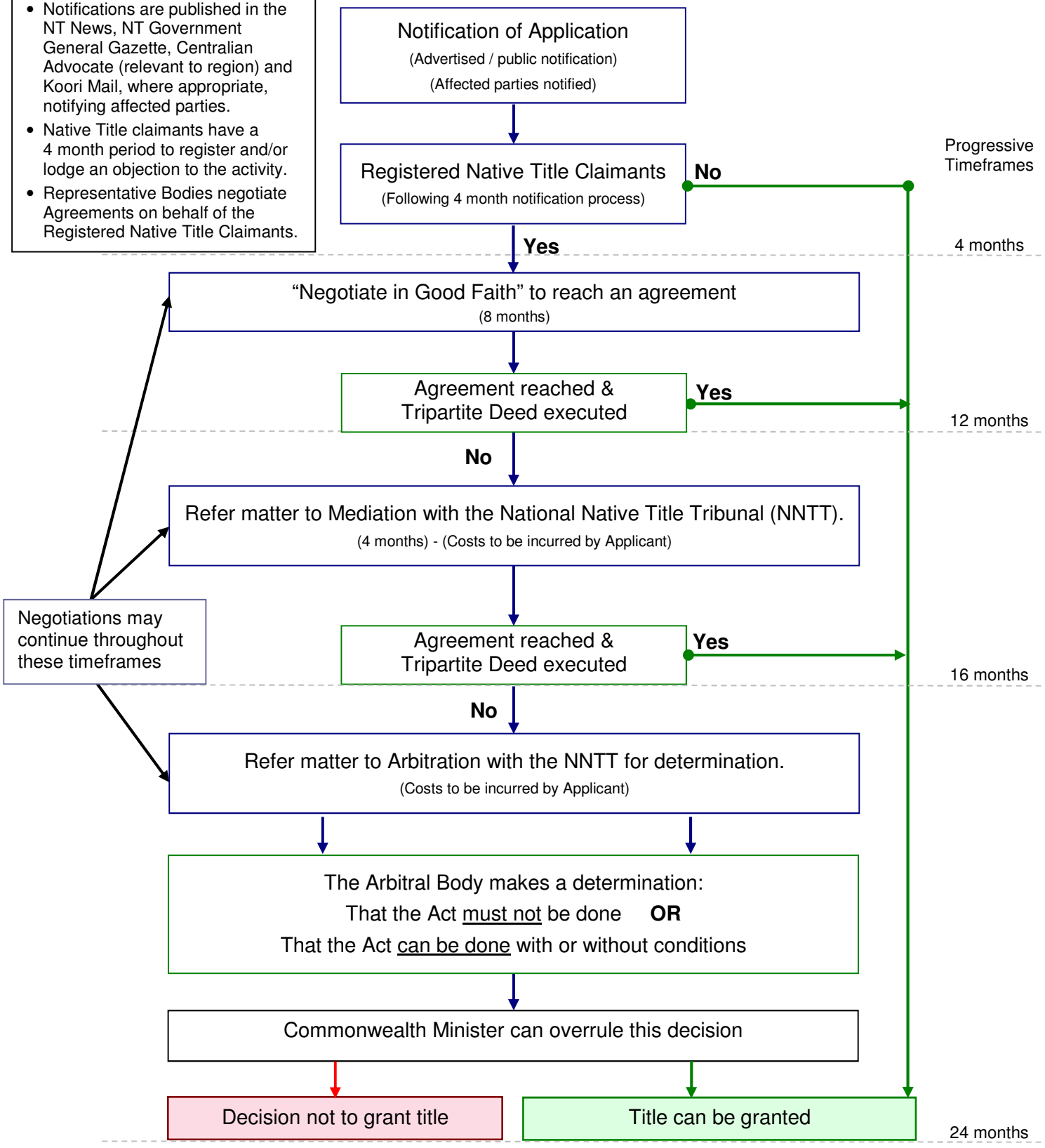
Address

5th Floor, Centrepoint Building
48-50 Smith St, Darwin NT 0800
Postal: GPO Box 4550, Darwin NT 0801, Australia

Read in conjunction with ALRA Flowchart and *Aboriginal Land Rights (Northern Territory) Act* 1976 (ALRA)

Appendix B - *Timeframes for Right to Negotiate Process for Title Applications on Native Title Affected Land*

- Notifications are published in the NT News, NT Government General Gazette, Centralian Advocate (relevant to region) and Koori Mail, where appropriate, notifying affected parties.
- Native Title claimants have a 4 month period to register and/or lodge an objection to the activity.
- Representative Bodies negotiate Agreements on behalf of the Registered Native Title Claimants.



NOTE: All legislative requirements must be achieved prior to the grant of an application.
The above timeframes are indicative, although all parties are to "negotiate in good faith" to progress applications to grant.
A representative body can negotiate an agreement on behalf of native title holders before a Native Title claim is lodged which may preclude the need for a claim and avoid the Right to Negotiate process.

Appendix B - *Exploration and Mining on Native Title Affected Land*

Introduction

The two main categories of land tenure in the Northern Territory, excluding townships, are Aboriginal Freehold (ABF) and Pastoral Lease.

Applications for exploration and/or mining on Pastoral Lease land may be subject to the *Native Title* Act (NTA) *1993*.

Applications are advertised under the NTA;

- Expedited Procedure; or
- Right to Negotiate Procedure.

NB: all petroleum applications are advertised under the Right to Negotiate Procedure

Expedited Procedure

Exploration licence applications (ELA) advertised under the expedited procedure will be subject to conditions to protect the rights and interests of the Native Title Parties pursuant to NTA s.237.

The Department ensures legislative compliance and that the public notification processes for each application are met.

Following public notification, a period of 4 months is allowed for registered Native Title Claimants to lodge an objection to the expedited process with the National Native Title Tribunal (NNTT).

The NNTT is the arbitral body responsible for conducting hearings, mediations and arbitration matters in the Northern Territory.

Where NO objections are lodged the exploration licence application is granted.

Where objections are lodged, a hearing is facilitated by the NNTT. The applicant and the registered Native Title Claimants are required to negotiate an agreement. It is a requirement of the NTA that negotiations be carried out "in good faith".

Agreements between the parties may be reached at any stage during the expedited procedure resulting in the withdrawal of the objection.

When an objection is dismissed by the NNTT the exploration licence application is granted.

When an objection is upheld by the NNTT the exploration licence application proceeds through the Right to Negotiate process.

When negotiations stall or no agreement is reached in mediation the matter may progressed to arbitration.

Right to Negotiate Procedure (RTN)

The RTN process is used for high impact mining ventures and all Petroleum negotiations on Native Title affected land.

The RTN public notification period of 4 months allows the Native Title Claimants to register and if required, to lodge an objection with the NNTT.

The registered Native Title Claimants, the applicant, the Northern Territory Government and the relevant Land Council execute a Tripartite Deed, prior to the grant of the application.

The Tripartite Deed has an underlying Ancillary Agreement between the Land Council representing the registered Native Title Claimants and the applicant.

The Northern Territory Government, through the Department of Mines and Energy, Mineral Titles Division, case manages applications through the RTN procedure.

The *Native Title Act* requires that negotiations be carried out "in good faith". The Department of Mines and Energy has an expectation that negotiations to reach an agreement take place within firm timeframes. (Refer '*Timeframes for the Right to Negotiate Process for Title Applications on Native Title Affected Land*')

If substantial progress has not been achieved, if negotiations have stalled and/or no agreement is reached within these expected timeframes the matter will be placed in mediation and if required, progressed to arbitration with the NNTT.

Indigenous Land Use Agreements (ILUA)

Applications for exploration and mining tenure may also be granted where the applicant and the Native Title Representative Body enters into an ILUA.

These are flexible agreements that can provide for various activities including exploration and mining activities, suitable for small exploration or large mining projects.

Contact Details

Native Title & Aboriginal Land Rights Unit
Tel: +61 8 8999 5322
Fax: +61 8 8981 7106
Email: NTALRUnit@nt.gov.au
Web: www.minerals.nt.gov.au/ntalr
TIS: www.minerals.nt.gov.au/tis

Address

5th Floor,
Centrepoint Building
48-50 Smith St,
Darwin NT 0800, Australia

Postal: GPO Box 4550
Darwin NT 0801 Australia

Read this document in conjunction with:

- the Native Title Expedited Flowchart;
- the Native Title RTN Flowchart; and
- the *Native Title Act 1993*

Petroleum Guideline Disclaimer

The material in this guideline is provided for general information only. The material is made available on the understanding that the Northern Territory is not providing legal advice.

Before relying on the material in any important manner, a user should:

- carefully evaluate the accuracy, currency, completeness and relevance of the information for the purpose for which it is to be used; and
- obtain appropriate professional/legal advice relevant to the user's particular circumstances.

In some cases the material may incorporate or summarise views, guidelines or recommendations of third parties. Such material is assembled in good faith, but does not necessarily reflect the considered views of the Northern Territory or indicate a commitment to a particular course of action.

The Northern Territory does not accept responsibility for the accuracy or completeness of any material contained in these guidelines and recommends that users exercise their own skill and care with respect to its use.

2. Guideline on the Criteria for Assessment of Petroleum Exploration Permit Applications

Criteria for Assessment of Petroleum Exploration Permit Applications

The Northern Territory Government has a priority aim to encourage aggressive exploration of energy resources, ensuring that prospective oil and gas reserves are explored for, discovered and developed efficiently and expediently as practicable.

This document sets out the criteria for assessing applications lodged under the Northern Territory *Petroleum Act* and *Petroleum* (*Submerged Lands) Act* for the award of a petroleum exploration permit (permit), the renewal of a permit and other applications relevant to exploration and production.

In any submission for the award of a permit, applicants will be expected to take into account all relevant information, such as environment protection, heritage and cultural issues which could impose added requirements on the grant of tenure.

An applicant must first satisfy the Minister for Mines and Energy (the Minister) of the capacity to undertake the proposed five (5) year work program, particularly:

- Demonstrable technical expertise that will meet the five (5) year exploration program as offered in the application;
- Assurances that the applicant has the financial resources to fund the exploration program in the first two (2) years and continue to have access to sufficient resources to meet the requirements of the proposed five (5) year work program including evidence of the applicant's ability to raise additional funding for exploration purposes where implied;
- Applicant's past performance in other petroleum exploration areas in Australia or, if relevant, elsewhere;
- Evidence of performance in a similar area either as operator or partner in a Joint Venture.

New Permit Applications

As of 1 January 2014, the legislation provides for multiple applications over the same vacant areas leading to a competitive application regime.

Permit applications received will be assessed against the criteria by qualified departmental officers within the Department of Mines and Energy. A report and recommendations to approve or not approve the grant of a permit will be prepared for the Minister (delegate).

Applications should be submitted in writing and will be assessed on the information provided, together with any additional information requested by the Minister (delegate). Applicants may also be invited to attend an interview with the department to clarify information provided.

In the recommendation to the Minister (delegate), consideration of the applicant's past performance in relation to meeting work commitments and environmental management in Australia and, if relevant, elsewhere is considered.

Consideration of past performance also extends to prior applications where applicants have failed to comply with the negotiations in good faith principles of the *Native Title Act* 1993 (Cwth) or similar

negotiations under the Aboriginal Land Rights (NT) Act (Cwth) or other reasons as to why past applications have not been successful.

Compliance with previous reporting and data submission requirements will also be considered.

Whilst assessments will take into consideration the prospectivity of an area (highly prospective or green field) the minimum guaranteed work program value (years one and two) cannot be reduced once the permit has been awarded.

Work programs proposed must significantly advance the exploration status of the area with the aim to develop that resource as soon as possible.

When assessing an application, the following will be taken into account; but does not exclude other requirements.

- Financial resources and technical expertise to execute the full five (5) years of proposed exploration and development activities;
- The extent of which the applicant's technical assessment supports the level of seismic surveying and the number of conceptual targets of wells proposed in the application;
- The amount, type and timing of seismic surveying or equivalent activity to be carried out and/or accessing existing non-exclusive seismic data;
- The number and timing of wells to be drilled, provided there is an adequate supporting program of geological and geophysical work;
- Expenditure, realistic and relevant to exploration activities and relevant to the prospectiveness of the area;
- Other surveying, data acquisition and reprocessing to be carried out;
- Pre-purchased, non-exclusive seismic data will not form part of the work program, but any interpretation of that data will be taken into account in assessing the merits of the work;
- Significant appraisal works over any previous petroleum discoveries within the area;
- Past exploration performance history; and
- Applicant's engagement of local employment and or community, including Indigenous employment.

In summary, a minimum acceptable work program should include (but not be limited to) the following:

- Years 1 - 2 substantial geophysical (seismic, magneto-telluric, gravity or magnetic) exploration activity, either aerial or ground;
- Year 3 - more extensive seismic that leads to drilling a well/wells – including a well;
- Year 4 - Exploration/appraisal drilling of well/wells;
- Year 5 - Geological analysis to firm up; identify prospective areas of the tenure for consideration of detailed assessment, pilot-production, production, tenure renewal and or relinquishment of land area.

Upon grant, titleholders must undertake each component of the work program in the permit area(s) within the prescribed year

If a titleholder has more than one permit (non-contiguous), expenditure in one permit cannot be substituted for expenditure in another unless it can be proven that the program to expedite exploration will benefit both areas. Proposed work commitment expenditure must be spent within each permit as indicated in the initial work program.

Failure to complete the work program commitments especially on the minimum guaranteed first two (2) years may result in the commencement of permit cancellation proceedings and will impact on the considerations for renewal of tenure, waiver applications, suspension of work program applications etc.

Failure to observe requirements for timely submission of data, including annual reports to Northern Territory Geological Survey is also to be taken into consideration.

Permit Renewal

An application for renewal of a permit is required to be submitted to the Minister (delegate) no earlier than six (6) months, but no later than three (3) months before the expiration of the permit. The Minister (delegate) may not renew the permit more than twice.

The Minister's (delegate) approval is required for late renewal applications and must be obtained before the three (3) month expiry timeframe date. Failure to submit a renewal application within that timeframe may result in full surrender of the permit area.

A renewal application must include a comprehensive report of the previous five (5) year work commitment program, findings and results. Additionally, the application is to include the proposed work program towards development for each year of the renewal term and a report on the strategic exploration plan going forward.

Fifty per cent (50%) of the acreage is required to be relinquished upon renewal and a tenure map showing proposed relinquishment blocks should be submitted with the renewal application. An exemption to relinquish blocks may be granted (for 12 months) if the titleholder/s can provide significant evidence as to the reasons why they should retain the additional acreage for an additional 12 months after renewal.

Permit renewal of more than 50% of existing tenure or acceptance of waiver to reduce tenure is not guaranteed.

Altering Work Programs –Variation, Suspension, Extension, Wavier

Alterations to work programs of Permits

An application to suspend, extend, waiver or vary permit conditions is required to be submitted within three (3) months prior to expiry of the current work program year. Applications will be considered on a *case by case* basis; however the first two (2) years of a work program must be satisfied.

For the purpose of work program alterations and where a Permittee holds a number of permits, each permit is to be considered as a separate entity.

- ***Variation***

All variations are subject to the discretion of the Department of Mines and Energy and are considered on a *case by case* basis. Work program values ***cannot*** be reduced. In general, wells will not be permitted to be substituted by other work (e.g. seismic). A presentation to the Department on any type of variation to the work program is encouraged.

Work programs may be accelerated at any time, (expenditures cannot be advanced to the following year) however prior notification is required.

Circumstances where a variation application may be considered by the Department of Mines and Energy are as follows:

- Alternative work program is similar to or of a superior technique and meets or exceeds the objective of the original commitment;
- There is substantial and compelling evidence that the work program should be varied on technical grounds and the Permittee may renegotiate the entire secondary term prior to entering Year 3 or prior to entering any of the years after the secondary term.

- ***Suspension***

A suspension application will only apply to the term of the active year of the permit.

Commercial circumstances that are common risks in the industry would not normally be considered; for example, changes in oil prices, difficulty attracting farm-ins, avoidable delays in contracting a rig and or disappointing drilling results. Also, it is not acceptable for a permittee to expect a suspension if a decision is made to undertake new seismic surveying (additional to the

current work program). This type of activity is commercially driven and should be considered in the initial work program or through a variation application.

During suspension the Department of Mines and Energy will require regular reporting on the progress of activities.

Suspensions do not exceed one (1) year.

- ***Extension***

Extension of a permit (beyond normal term of 5 years) will not be considered unless substantial work has been carried out in previous years and there is demonstrated technical evidence for the application and a strategic plan transitional to moving forward to development.

Extensions do not exceed one (1) year.

- ***Waiver***

Waiver of mandatory 50% permit relinquishment will only be considered if the title holder can demonstrate previous aggressive exploration that has indicated resources exist over all designated areas and will require 'retention' of these areas until the full or less potential is established.

End.

3. Guideline for Applications for Drilling or Workover Rig Activities

Applications for Drilling or Workover Rig Activities

The Department of Mines and Energy (DME) categorizes applications for activities involving drilling or workover rigs as either *Project Applications* or *Operational Applications*.

Project Applications – occur where approval is required to **commence** (and then carry out) an entire project for which an approval has **not** already been granted.

Examples of projects requiring an application for approval

- Entering a site to drill a new well
- Re-entering and working over an existing well
- Re-entering a well to carry out any particular activity

Operational Applications ***** – occur where approval is required to carry out a particular activity within a project which **has already commenced**; that is, an activity where Project Approval has already been granted. Operational activities are those leading to a specific change to the wellbore geometry and so for this reason, are activities that go outside the already approved work program.

Examples of well activities requiring an application for approval

- *Any activity that goes outside the already approved work program*
- *Side tracking a well*
- *Suspension (Guidelines available on website)*
- *Abandonment*
- *Flow testing*
- *Fracture Stimulating*
- *Well Comple*tion

*** PLEASE NOTE:**

Project Applications are assessed before the drilling rig commences operations whereas Operational Applications are assessed whilst the rig is in operation.

Given the high cost of rig day rates, this can place considerable demands on all human resources. For this reason, it is the responsibility of operators to draw to the Regulator's attention, notice of any impending operation **as soon as it becomes a possibility.** To avoid rig delays, operators are strongly encouraged to submit draft applications earlier than the 5 day assessment timeframe.

1. PROJECT APPLICATIONS

1. **Allow a minimum of 30 days for assessment**
2. Depending on the type of project, the following documentation is or may be required as part of the assessment process of a Project Application:
    - A letter of application that makes specific reference to Clause(s) under which the activity requires approval, and is signed by the custodian of the project.
    - Drilling, Workover or Stimulation Program ^
    - Environment Plan (*see below) ^
    - Safety Management Plan ^
    - Insurance Certificate(s)
    - Oil Spill Contingency Plan ^
    - Emergency Response Plan ^
    - Baseline Water Study (particularly for Stimulation Projects) ^
    - MSDSs for lodgement on DME's Website
    - a completed Rehabilitation Security Calculation Form
    - copies of Cultural Clearances and letters from stakeholders

    - ***Unless addressed within the Environment Plan, separate documents to be submitted also include: Bushfire Management Plan, Erosion and Sediment Control Plan, Weed Management Plan, Dust Management Plan, Traffic Management Plan, Biodiversity Management Plan, Waste Management Plan**

    ^ The proposed program should be identified by document number and current version number and be dated and signed off by the custodian of the project.
3. Before Final Approval is granted:
    - Payment of Rehabilitation Security Deposit is required.
    - Environment Plan Summary for lodgement on DME's Website should be submitted.

NOTE: OPERATIONS ARE NOT TO COMMENCE UNTIL ALL REQUIRED APPROVALS FROM NT DME AND OTHER APPROVING AUTHORITIES HAVE BEEN OBTAINED

2. OPERATIONAL APPLICATIONS

- **Allow a minimum of 3 days for assessment ; HOWEVER, SIGNIFICANT CHANGES COULD REQUIRE SUBSTANTIALLY LONGER TO ASSESS**
- The letter of application should make specific reference to Clause(s) under which the activity requires approval, and be signed by the custodian of the project.
- The application letter should be supported by:
    - Work Program proposed to be carried out - including current well schematic. The version of the work program should be stated and the document should have been dated and signed off by the responsible parties
    - any bridging documents or addendums to the project Environmental Management Plan or other originally submitted document, that may be pertinent
    - The proposed final well schematic.

3. CORRESPONDENCE

All correspondence concerning project or operational applications (letters, supporting documents etc.) **should be in electronic format only**, and be sent by email to:

DIRECTOR OF ENERGY
Attention: Team Leader Petroleum Operations

at: directorenergy@nt.gov.au and petroleum.operations@nt.gov.au

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ADDITIONAL GUIDING INFORMATION

- Checklists and guidelines for various petroleum activities are available on the DME Website at: http://www.nt.gov.au/d/Minerals_Energy/index.cfm?header=Energy%20Documentation

- Contact the **Petroleum Operations Team** on petroleum.operations@nt.gov.au for further information.

- END -

4. Guideline for Environmental Plan Requirements

ENVIRONMENT PLAN (EP) REQUIREMENTS

EP Submission and Format

The EP should be submitted in electronic format to (a) directorenergy@nt.gov.au
(b) petroleum.operations@nt.gov.au

Generally:

The EP should:

- Have a version number or document reference for the EP
- Contain a document revision history
- Include project proponent details
- A document distribution list for the EP

The EP should contain at least the following sections:*

- Corporate Environmental Policy
- Environmental Legislation and other requirements
- Project Activity Description
- Environment Description
- Environmental Risks and Impacts Description and Assessment.
- Performance Objectives, Standards and Measurement Criteria
- Implementation Strategy
- Reporting
- Consultation
- Rehabilitation Strategy

* Other subjects that the applicant feels would assist the Department in assessing the EP may be included

Section Contents:

1. Corporate Environmental Policy

This section should:

- Contain the Operator's Corporate Environmental Policy.
- Commit the operator to reducing the environmental impacts and risks.
- Set environmental objectives and targets.
- Identify those responsible for implementing environmental corporate policy.
- Be approved by someone from the Senior Management Team.

2. Environmental Legislation and other requirements

This section should:

- Identify all the relevant legislation.
- Identify all relevant agreements.
- Identify all relevant codes of practice.

3. Project Activity Description

This section should contain:

- The proposed project operations relevant to the environment e.g. drilling, seismic, well testing, land clearing etc.
- An exact location of the proposed activity. i.e. legible maps of appropriate size and scale.
- General details of: support facilities/plant and equipment etc. with supporting maps, facility layouts, specifications, etc.
- Technical specifications relevant to the interaction of the activity with the environment: e.g. drilling rig specifications, seismic vehicles etc.
- Contractors and support companies; number of personnel etc.
- Proposed timetables for the expected commencement date of the project e.g. spud date etc and major activities within the project execution timeframe.

4. Environment Description

This section should:

- Describe the:
  - Existing natural physical environment including geography, geology, climate, hydrogeology, hydrology, soils etc.
  - Existing natural biological environment including bioregions, flora and fauna, birds, fishes, reptiles, mammals, feral animals etc.
  - Cultural environment including Indigenous, European and others.
  - Current socio-economic environment including habitational, recreational and commercial and tourism.
- Include the key values and sensitive aspects of the environment; whether within, or immediately close to, the project activity:
  - Sacred and Cultural Heritage sites
  - Protected areas/Conservation Areas
  - Rare or endangered flora and fauna
  - Areas of significant habitat
  - Fire regime

.5. Environmental Risks and Impacts, Description and Assessment

This section should contain:

- The Risk Assessment Methodology, including:
  - details of scoping process employed to identify impacts and risks
  - any hazard identification workshops conducted
  - definition of consequence as moderate to catastrophic
  - Summarization of risk assessment results in a table/matrix format.
- Identification, description and assessment of the environmental impacts and risks, (rising directly or indirectly from the activity) and their significance. For example:
  - Noise
  - Soil disturbances
  - Alteration of/disruption to local traffic
  - Fuel, oil or chemical spills
  - Overflow of drill cuttings or drilling mud
  - Reduced water quality. (A baseline water quality assessment may be required.)
  - Impacts on flora and fauna
  - Displacement of recreational users/other stakeholders
  - Introduction of noxious weeds, exotic flora, vermin and animal diseases

- The evaluated impacts and risks (likelihood and consequence), including:
    - Risk treatments
    - Determination of likelihood based on known frequency, available industry data or a statistical review
    - Determination of consequence based on specific ecological values, physical or social parameters or sensitivity of the area
    - Consequence rating that relates directly to reportable incident requirements
    - Use of industry models if relevant to quantify risks including model verification and validation

NOTE: Quantitative or qualitative measures should be used in assessment of environmental risks and impacts and a precautionary approach should be applied to evaluation of the environmental risks.

6. Performance Objectives, Standards and Measurement Criteria

This section should contain:

- The environmental performance objectives. These objectives should relate to the identification and assessment of the environmental impacts and risks, e.g. minimize impacts on environment from chemical spills etc. The objectives should also be detailed enough to link to the impacts and risks.
- Environmental performance standards. i.e. Compliance with company procedures and Industry codes of practice and government regulations.
- Measurement criteria that:
    - addresses the legislative and other controls that manage the environmental features of the activity. e.g. capacity to measure all spills, surface discharges etc.
    - relates to the performance objectives and standards
    - allows performance to be measured, e.g. Inspections, Audits etc.
    - enables whether an activity is meeting its environmental objectives and standards

7. Implementation Strategy

This section should list how the operator will address each environmental concern and should contain:

- Operation systems, practices and procedures that:
    - will be utilized to ensure that environmental impacts and risks are reduced to an agreed and acceptable level; and
    - are specific to the environmental performance objectives and standards.
- Establishment of a clear chain of command including roles and responsibilities of personnel for the implementation, management and review of the EP, which includes permit holder, operator and contractors.

  Additional issues to be addressed include:
    - Who is responsible for induction trainings?
    - Who is responsible for monitoring discharges?
    - Who is responsible for reporting?
    - Who keeps the records of all incidents?
    - Who is responsible for auditing? etc.
- Measures to ensure that employees and contractors are made aware of their responsibilities and have appropriate competencies and trainings. There should be plans in place for additional training for appropriate skills and support for ongoing training.
- Planned monitoring, audit, management of non-conformance and review of environmental performance. For example:
    - monitoring can be spot checks, daily meetings, regular inspections etc.
    - internal and external audits
    - method of handling and investigating non-conformance including arrangements for tracking and closing out of non-conformances.
- Specific reference to an appropriate Emergency Response Plan as well as an Oil Spill Plan that the operator has in place.
- A recording system that maintains quantitative records of emissions and discharges to the environment which can be monitored and audited against the performance standards and measurement criteria.

This includes:

- Induction records
- Wastes records
- Emissions and discharges records
- Hazardous goods manifests
- Non-compliance and corrective action records
- Internal audits and inspection records
- Equipment maintenance records
- Integrity checks records

8. Reporting

This section should contain:

- Arrangements for the Routine Reporting about the activity that is carried out. The reporting arrangements must be appropriate and adequate in relation to the size and nature of the activity.

  Example of reports:
  - Daily/weekly status reports
  - Monthly records of emissions and discharges for longer term projects
  - Annual reports for longer term projects (summary and analysis of incidents, trends in emissions and discharges, summary and analysis of non-conformances, summary and analysis of complaints, results of research or ongoing monitoring programs, technical improvements, consultation undertaken, trends in waste usage and generation, trends in chemical usage).
  - Close out reports for short term or intermittent projects submitted 3 months after completion of work (results of audits, summary of incidents, complaints, non-conformances, emissions and discharges, results of emergency response exercises, rehabilitation)
  - Incident Reporting arrangements including appropriate reporting bodies and timeframes for reporting.

9. Consultation

This section should contain:

- A consultation report which includes:
  - List of all relevant stakeholders consulted
  - Name and tile of persons consulted
  - Issues discussed and whether the parties were provided with factual information relevant to the activity
  - Specific concerns and interests raised during the consultations, actions taken to address them and current status of this matter (i.e. resolved/pending/not resolved, how? why?)
- Processes and arrangements for ongoing consultation with relevant stakeholders throughout the life of the project including:
  - What, how, how often and to whom information will be disseminated?
  - Avenue for stakeholders to communicate concerns, queries, feedback
  - Copies of all stakeholder approved certificates.

10. Rehabilitation Strategy

This section should contain:

- Details and description of proposed strategies which include:
  - Assisted natural regeneration
  - Re-spreading of topsoil and vegetative matter
  - Seeding
  - Biological rehabilitation
  - Advice and assistance from local land-care groups etc.

Additional Requirements

Project Approval

The approval of the project covered by the EP is conditional to the operator providing the following:

- ***Water Management***
    - *Plans for regular testing of local water bores before, during and after the project.*
- ***Chemicals Disclosure (especially for Fraccing Projects)***
    - *List of all chemicals to be used. These are to be made available for public record on NT DME's website.*
- ***Environment Rehabilitation Security Bond***
    - *Submission of Security Bond Calculation that covers all the rehabilitation management areas.*
    - *Evidence of Final Payment.*

After Approval

- ***Environment Plan Summary***
    - *Within one week of obtaining approval, an EP Summary has to be submitted to be made available for public record on the NT DME's website.*

Contact the **Petroleum Operations Team** on petroleum.operations@nt.gov.au for further information.

- END -

5. Checklist – Onshore Environmental Plan

Northern Territory Government

DEPARTMENT OF MINES AND ENERGY

Petroleum Operations

ENVIRONMENT PLAN ASSESSMENT

Assessor/s' Name/s:	
Assessment Date:	
EP Name:	
Operator Name: *(Permit Holder/Registered Operator)* **Address:** **Contact:**	
Type of Activity:	**Civil Works - Access Roads, Wellpad** ☐ **Drilling Operations** ☐ **Survey Operations** ☐ **Well Testing** ☐ **Re-entry /Workover/Recompletion** ☐ **Well Stimulation (including Fraccing)** ☐ **Field Development** ☐ **Construction of Production Facilities** ☐ **Well Abandonment** ☐ **Decommissioning of Production Facilities** ☐

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
i) Is the initial and final submission of the EP in electronic form?			
ii) Does the EP have a version number and date on it?			

1. CORPORATE ENVIRONMENTAL POLICY

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
1.1 Does the EP include the operator's corporate environmental policy?			
1.2 Does the policy recognise commitment to reducing environmental impacts and risks?			
1.3 Does the policy provide the setting of environmental objectives and targets?			
1.4 Is the policy approved by senior management?			
1.5 Does the policy identify person/s responsible for implementing environmental policy?			

2. ENVIRONMENTAL LEGISLATION AND OTHER REQUIREMENTS

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
2.1 Does the EP identify all relevant legislation that must be complied with?			
2.2 Does the EP identify all relevant international agreements?			
2.3 Does the EP include specific legislative requirements and how the operator will address each?			
2.4 Does the EP, as a whole, meet the legislative requirements?			
2.5 For longer term projects (e.g. *>1* yr), does the EP have a monitoring system to ensure changes in environmental legislation are met? • Rely on consultant • Regular contact with regulator			
2.6 Have any codes of practice been mentioned?		**APPEA (WA) specifically for Fraccing.**	

3. DESCRIPTION OF AN ACTIVITY

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
3.1 Does the EP contain an exact location of the proposed activity? • Legible map and/or description outlining basin, coordinates, permit etc • Legible map and/or description relevant to nearby environment sensitive areas Note: The map must be of an appropriate size and scale			
3.2 Does the activity cross boundaries with other permits? • Have access authorities been applied for and obtained?			
3.3 Are the general details of any support facilities or other contractors specified? • Name and description • Name and description of support and supply vessels incl. helicopters • Specs of all facilities • Map Layout of facilities • Number of rig personnel • Names of contractors and subcontractors outlined • Vehicles, Equipment, Machineries to be used at the drilling site etc.			
3.4 What is the estimated quantity of water to be used and where is the source? • Have groundwater salinities (ppm) been provided? • Will independent Groundwater Monitoring be taking place? • Frequency of testing?		**Does it include monitoring before, during and after?**	

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
3.5 Does the EP outline how ALL waste (accommodation & operational) will be disposed? • Disposal Method • Disposal Site/Condition. Is there are *Waster Management Plan* in place?		**For Produced Fluids:** • **Does the Environment Plan state the end delivery point for all fluids:** ○ **Oil** ○ **Gas** ○ **Water** ○ **Fraccing Fluids** ○ **Drilling Mud & Brine** ○ **Accommodation wastes & water**	
3.6 Does the EP outline the proposed operations of the activity relevant to the environment? • Surface area of operations • Borrow pits • Production testing if drilling • Pipe works for the operations • Use of machineries for preparing survey lines. • Construction of Water Bores if applicable.			
3.7 Does the EP contain the proposed timetables? • Commencement and completion dates/estimated weather down time/estimated equipment failure time etc.			
3.8 For seismic surveys, does the EP contain procedures for road crossings? Approval given by DoT? Traffic Management Plan in place?			

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
3.9 Are the following plans in place to cover for the activity? *(where applicable).* • Erosion and Sediment Control Plan (ESCP). This should include additional details about rehabilitation measure and timings that are consistent with the Department of Land Resource Management (DLRM) guidelines. • Weed Management Plan consistent with DLRM guidelines. • Dust Management Plan • Traffic Management Plan, which outlines measures for all works that affect the safety and efficiency of public roads. • Biodiversity Management Plan which provides adequate protection or relocation of threatened flora or fauna and is endorsed by DLRM. • Waste Management Plan. • Fire Management Plan ***Note**: The above plans can be covered by risk management measures or HSE systems, standards and policies the operator has.*			

4. DESCRIPTION OF THE ENVIRONMENT

QUESTIONS	Y/N/NA	COMMENTS and EP Section	By Date/ Revision
4.1 Does the EP describe the: • Natural physical environment including geography, geology, climate, • Fire Regime (FMP) • Natural biological environment including flora and fauna, (invertebrates, birds, reptiles, mammals). • Cultural environment including indigenous, European and others • Socio-economic environment including recreational and commercial and tourism.			
4.2 Are key values and sensitive aspects of the environment identified whether within or immediately adjacent to activity: • Sacred/Cultural heritage sites • Protected areas • Protected/rare/endangered flora and fauna • Areas of significant habitat			

5. DESCRIPTION AND ASSESSMENT OF ENVIRONMENTAL RISKS AND IMPACTS

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
5.1 Does the EP identify the risk assessment methodology, including • Details of scoping process employed to identify impacts and risks • Hazard identification workshop • Define consequence as moderate to catastrophic. Note: relevant for reportable incidents			
5.2 Does the EP identify and describe the environmental impacts and risks and their significance arising directly or indirectly from the activity? • Noise • Soil disturbances • Disruption to local traffic • Fuel, Oil, Chemical Spills • Overflow of drill cuttings or mud. • All waste, accommodation & operational			
5.3 Does the EP identify and assess the environmental impacts and risks in relation to the environment? • Reduced water quality. • Impacts on fauna • Death of fauna • Displacement of other users/ other stakeholders • Introduction of noxious weeds, exotic flora, vermin and animal diseases.			

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
5.4 Does the EP identify and assess the environmental impacts and risks associated with ***Fracing Operations***? • Reduced Water quality (requires salinities (ppm) of known aquifers). • Aquifer contamination. • Fracture propagation into overlying aquifer. • Leakage to aquifer from loss of well integrity. • Excessive usage of groundwater. • Seismicity & Pressure Monitoring • Cease – triggers to prevent exceeding allowable surface and down-hole pressures • Radioactivity • Handling and Disposal of Produced and Flowback fluids		**Required in EP to cover Fraccing Operations:** • *Details of Baseline Water Assessment of known Water/Aquifer Systems.* • *Ongoing Monitoring Plans – (Before, During and After).* • *Disclosure of MSDSs or List of Chemicals to be used.* • *Details of Water Source and Usage.* • *Fracture Propagation Model.* • *Final Well Completion Schematic including details of Well Design and Construction.* • *Procedures for safe handling and disposal of produced and flowback fluids.*	
5.5 Does the EP evaluate impacts and risks (likelihood and consequence), including • Risk treatments • Is determination of likelihood been based on known frequency, available industry data or a statistical review? • Is determination of consequence based on specific ecological values, physical or social parameters, sensitivity of the area? • Consequence rating relates directly to reportable incident requirements – these meet DA expectations? • Use of industry standard models to quantify risk including model verification and validation e.g. oil spill modeling etc.			

6. PERFORMANCE OBJECTIVES, STANDARDS AND MEASUREMENT CRITERIA

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
6.1 Does the EP contain environmental performance objectives? • Do they relate to the identification and assessment of environmental impacts and risks e.g. minimize impacts on environment from routine discharges • Are the objectives detailed enough to link to the risks?			
6.2 Does the EP contain environmental performance standards? • Compliance with company procedures • Compliance with Industry codes of practice			
6.3 Does the EP contain measurement criteria? • Capacity to measure all spills/ discharges etc.			
6.4 Does the measurement criteria: • relate to the performance objectives and standards • allow performance to be measured • enable whether an activity is meeting its environmental objectives and standards			

7. IMPLEMENTATION STRATEGY

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
7.1 Does the IS include operational systems, practices and procedures to ensure that environmental impacts and risks are reduced to an agreed and acceptable level? • Is it specific to the environmental performance objectives and standards?			
7.2 Does the IS establish a clear chain of command including roles and responsibilities of personnel for the implementation, management and review of the EP? (Permit holder, Operator, Contractor) • Who is responsible for induction training? • Who is responsible for monitoring discharges? • Who is responsible for reporting? • Who holds the records • Who is responsible for auditing? • Who has authority to make decisions about these issues?			
7.3 Does the IS include measures to ensure that employees and contractors are aware of their EP related responsibilities and have appropriate competencies and training? • Is additional training required to provide appropriate skills? • Is ongoing training required			

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
7.4 Does the IS provide for the monitoring, audit, management of non conformance and review of environmental performance? • Monitoring can include spot checks, daily meetings, regular inspections etc. • Monitoring methodology described e.g. type of equipment, inspection regime, calibration technique and laboratory comparison if required • Internal and external audits • Method for handling and investigating non conformances including arrangements for the tracking and close out of non conformances			
7.5 Does the IS make reference to an appropriate Oil Spill Plan and Emergency Response Plan/Manual? • Are the contact details correct? • Has an exercise been conducted within last 12 months			

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
7.6 Does the IS maintain quantitative records of emissions and discharges to the environment which can be monitored and audited against the performance standards and measurement criteria? • Induction records • Waste records • Emissions and discharges • Hazardous good manifests • Non compliances and corrective actions records • Internal audits and inspections records • Equipment maintenance records • Integrity records			
7.7 Other • Has world's best practice been adopted? • Is continuous improvement encouraged? • Does the EP define and measure environmental risk?			

8. REPORTING ARRANGEMENTS

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
8.1 Does the EP include arrangements for routine reporting about the activity? • Daily/weekly status reports • Monthly records of emissions and discharges for longer term projects • Annual reports for longer term projects (summary and analysis of incidents, trends in emissions and discharges, summary and analysis of non conformances, summary and analysis of complaints, results of research or ongoing monitoring programs, technical improvements, consultation undertaken, trends in waste usage and generation, trends in chemical usage) • Close out reports for short term or intermittent projects submitted 3 months after completion of work (results of audits, summary of incidents, complaints, non conformances, emissions and discharges, results of emergency response exercises, rehabilitation) **NOTE:** The reporting arrangements must be appropriate and adequate in relation to the size and nature of the activity			
8.2 Does the EP include incident reporting arrangements? • Reporting bodies identified • Reporting timeframes			

9. CONSULTATION

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
9.1 Does the EP contain a consultation report? • List all relevant stakeholders • Name and title of position for persons contacted • Issues discussed and whether they were provided with factual information relevant to the activity • Concerns and interests raised during the consultations • Actions taken to address concerns			
9.2 Does the EP include processes for ongoing consultation with relevant stakeholders throughout the life of the project? • What, how, how often and to whom information will be disseminated? • Avenue for stakeholders to communicate concerns, queries, feedback			

10. REHABILITATION STRATEGY

QUESTIONS	Y/N/NA	COMMENTS and EP Sections	By Date/ Revision
9.3 Does the EP include a rehabilitation strategy? • Assisted natural regeneration? • Respreading of topsoil and vegetative matter? • Seeding? • Collection of local seeds during vegetation clearance? • Advice and assistance from local landcare groups? • Hydrocarbon impacted land? Biological rehabilitation? etc.			

11. BEFORE APPROVAL

QUESTIONS	Y/N/NA	COMMENTS
Has Operator been alerted of expectation to carry out the following? • **Water Management** Plans for regular testing of local water bores prior, during and after the project. • **Chemical Disclosure** *(especially for Fraccing Projects)* Provide list of chemicals to be used to be used. These are to be made available for public record on NT DME's website. • **Environment Rehabilitation Security Bond** Submission of security bond calculation that covers all the rehabilitation management areas. After acceptance of the bond calculation by NT DME, final evidence of payment is required to be submitted to NT DME.		

11. AFTER APPROVAL

QUESTIONS	Y/N/NA	COMMENTS
Has Operator been alerted of expectation to carry out the following? • **Environment Plan Summary** Within one week of obtaining operational approval, an EP Summary has to be submitted to be made available for public record on NT DME's website.		

1. INITIAL ASSESSMENT			
Assessor's Name:		**Date:**	
Assessor's Signature:			
2. SECOND ASSESSMENT			
Assessor's Name:		**Date:**	
Assessor's Signature:			
3. FINAL ASSESSMENT			
Assessor's Name:		**Date:**	
Assessor's Signature:			

6. Reviewing Onshore Drilling Program

Northern Territory Government

DEPARTMENT OF MINES AND ENERGY
Petroleum Operations

Onshore Drilling Program Assessment Checklist

Operator Name:		**Well Name:**	
Permit:		**Date:**	
Type of Drilling:		**Well Status:**	

* ***Applicable for Offshore only (3 mile limit)***

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
1.	Is the Drilling Program assigned a Document or Version number?	☐	
2.	Is there a Distribution List in the Drilling Program?	☐	
3.	Is Drilling Program Signed?	☐	
4.	Drilling Program Basis **** Does the program include a statement claiming all operations and equipment will comply with minimum API standards and company's safety management systems?***	☐	**Not recommended for approval if response is "NO"**
5.	Relevant Documents Identified.	☐	
6.	Well Summary/General Data/Well Card		
	• Well Type	☐	
	• Geographical Location	☐	
	• Block Number	☐	
	• Joint Venturers	☐	
	• Basin	☐	

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
	• Surface Coordinates	☐	
	• Subsurface Target Tolerance	☐	
	• Surface Location Tolerance	☐	
	• Tide Datum i.e. msl or LAT *	☐	
	• Rig Name	☐	
	• Rig Contractor	☐	
	• Planned Spud Date	☐	
	• Well Schematic *(Current)* **** Does program include a schematic of well cross section to include corresponding lithology with depth, thickness, ppm of aquifers clearly marked.***	☐	**Not recommended for approval if response is "NO"**
	• Well Schematic *(Proposed)* **** Does program include a schematic of well cross section to include corresponding lithology with depth, thickness, ppm of aquifers clearly marked.***	☐	**Not recommended for approval if response is "NO"**
	• RT Elevation, Drilling/Elevation Datum	☐	
	• Water Depth (msl) m*	☐	
	• Proposed Total Depth (TD)	☐	
	• Estimated Drilling Time (days)	☐	
	• Formation Objectives	☐	
	• Depth of Objectives	☐	
	• Offset Wells	☐	
	• Anticipated Costs	☐	
		Please tick (√) or	

No.	Key Items to Check	cross (X) the check boxes accordingly	Comments
7.	Rig Move Mobilisation	☐	
8.	Prospect Summary	☐	
9.	Previous Exploration Summary	☐	
10.	Geological Summary/Geological Information/ Geological Prognosis.	☐	
11.	Planned Drilling Summary/Sequence of Operations.	☐	
12.	Well Location Maps	☐	
13.	Permit Maps	☐	
14.	Geological/Production/Drilling Objectives		
.	• Safety and Environmental	☐	
.	• Geological and Reservoir	☐	
	• Drilling Engineering	☐	
	• Economical	☐	
15.	Expected Geological Structures	☐	
16.	Predicted Lithological Section	☐	
17.	Shallow Gas Potential	☐	
18.	Anticipated Hydrocarbons Potential with poisonous gases i.e. CO_2 and H_2S.	☐	
19.	Proposed Evaluation Program	☐	
20.	Drilling Safety Considerations	☐	
21.	Drilling and Safety Documentation	☐	
22.	Drilling Procedures **** Clear, sequential and Acceptable?***	☐	*If **NO**, please comment.*
		Please tick (√) or	

No.	Key Items to Check	cross (X) the check boxes accordingly	Comments
23.	Well Design Information		
	• Cementing Program **** Does the program include cement to surface for all casing strings?***	☐	**Not recommended for approval if response is "NO"**
	• Wellhead System & Equipment	☐	
	• Pore Pressure Gradient	☐	
	• Fracture Gradient	☐	
	• Key Offset Wells	☐	
	• Temperature Gradient	☐	
	• Lost Circulation	☐	
	• Casing Seat Selection	☐	
	• Casing Design Safety Factors	☐	
	• Contingent Liner	☐	
	• Leak Off Test & FIT **** For non-Production Casing.***	☐	**Not recommended for approval if response is "NO"**
	• Kick Tolerance Identified	☐	
	• Surveying Program	☐	
	• Drilling Data i.e. ROP, WOB, RPM, Flow, Pressure, Mud Weight In/Out, BOP Pressure Rating etc.	☐	
24.	Potential Drilling Hazards	☐	
25.	Real Time Logging Requirements	☐	
26.	Mud Logging and Sampling		
	• Cuttings	☐	
	• Bit Cutting Samples (note where they should be sent).	☐	
		Please tick (√) or	

No.	Key Items to Check	cross (X) the check boxes accordingly	Comments
	• Palynological Sampling i.e. Geochemical Analysis, Fluid Samples, Core Samples, Sample Dispatch from Wellsite/LWD, LWD Program, Wireline Electric Logs etc.	☐	
	• Mud Logging	☐	
27.	Coring	☐	
28.	Wireline Logging	☐	
29.	Production Testing	☐	
30.	Drilling Bits		
	• Rig Mud Pump	☐	
	• Bit Hydraulics	☐	
	• Deviation Requirements	☐	
	• Bottom Hole Assemblies	☐	
	• Suggested Stabilisers and BHA Requirements	☐	
31.	Drilling Fluid Type		
	• Fluid Properties	☐	
32.	Casing Program including Pressure Testing Schedule for Non-Production Casing	☐	
33.	Well Integrity Validation *(Production Casing)* **** Is validation method of production casing cementation explicitly stated? By Logging or pressure?***	☐	**Not recommended for approval if response is "NO"**
34.	BOP Systems and Safety		
	• Rotating Head Surface Diverter Diagram	☐	
		Please tick (√) or	

No.	Key Items to Check	cross (X) the check boxes accordingly	Comments
	• BOP Wellhead Diagram	☐	
	• BOP Requirements	☐	
	• Reference made to a Well Control Manual?	☐	
	• Kick Drills	☐	
	• Casing Test Pressures	☐	
	• Well Control Procedures	☐	
35.	BOP Operating Guidelines		
	• BOP Inspection and Actuation	☐	
	• Crew Training and Drills	☐	
	• BOP Records Requirements	☐	
	• BOP Maintenance Requirements	☐	
	• Shut-In Procedure Drilling and Tripping	☐	
36.	Drilling Rig/Equipment Specifications	☐	
37.	Prognosed Time-Depth Curve	☐	
38.	Environmental Management	☐	
39.	Workplace Health & Safety	☐	
40.	Logistics Information	☐	
41.	Reporting Arrangements **** As per the NT Schedule of Onshore Petroleum Exploration and Production Requirement 2012).***	☐ ☐	• ***Part V, Division 2*** • ***Part II, Division 4***
42.	Does the program contain triggers seeking the following Operational Approvals? • ***Side Tracking?*** • ***Flaring?**** • ***Testing?*** • ***Suspension or P & A***	☐	**Not recommended for approval if response is "NO"** **** For air drilling***
		Please tick (√) or	

No.	Key Items to Check	cross (X) the check boxes accordingly	Comments
43.	Contact List		
	• Operator	☐	
	• Contractors/Service Companies	☐	
44.	NT Schedule of Onshore Petroleum Exploration and Production Requirement 2012		
	• Overall, the drilling program satisfies and covers Part V, Division 1, Clauses 501 to 532 for Drilling and Workover.	☐	
	• Overall, the drilling program satisfies and covers Part II, Division 3, Clauses 271 to 283 for Air and Gas Drilling.	☐	

1. INITIAL NTDME ASSESSMENT

Assessor's Name:		***Date:***	
Assessor's Signature:			

2. SECOND NTDME ASSESSMENT

Assessor's Name:		***Date:***	
Assessor's Signature:			

3. FINAL NTDME ASSESSMENT

Assessor's Name:		***Date:***	
Assessor's Signature:			

7. Reviewing Workover and Stimulation Program

Northern Territory Government

DEPARTMENT OF MINES AND ENERGY
Petroleum Operations

Onshore Workover/Stimulation Program Assessment

Operator Name:		**Well Name:**	
Permit:		**Date:**	
Type of Activity:		**Well Status:**	

* *Applicable for Offshore only (3 mile limit)*

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
1.	Is the Workover/Stimulation Program assigned a Document or Version number?	☐	
2.	Is there a Distribution List in the Workover/Stimulation Program?	☐	
3.	Is Workover/Stimulation Program Signed?	☐	
4.	Workover/Stimulation Program Basis Does the program include a statement claiming all operations and equipment will comply with minimum API standards and company's safety management systems?	☐	**Not recommended for approval if response is "No"**
5.	Relevant Documents Identified	☐	
6.	Relevant SOPs Identified	☐	
7.	Appropriate Legislations, Regulations, Code of Practices etc. mentioned?	☐	
8.	Cost Code & Purchase Orders	☐	
9.	Well Data Summary		
	• Well Type	☐	
	• Well Location Map	☐	
	• Block Number	☐	

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
	• Joint Venturers/Partners	☐	
	• Basin	☐	
	• Surface Coordinates	☐	
	• Tide Datum i.e. msl or LAT *	☐	
	• Workover Rig Name	☐	
	• Workover/Stimulation Contractor	☐	
	• Planned Date to Start	☐	
	• Current Well Details	☐	
	• Current Well Schematic Schematic of well cross section to include corresponding lithology with depth, thickness, ppm of aquifers clearly marked.	☐	**Not recommended for approval if response is "No"**
	• Proposed Well Details Schematic of well cross section to include corresponding lithology with depth thickness, ppm of aquifers clearly marked.	☐	**Not recommended for approval if response is "No"**
	• Wellhead and Christmas Tree Details	☐	
	• Existing Perforations	☐	
	• Gun/Charge Specifications	☐	
	• Completion Mechanical Properties	☐	
	• RT Elevation	☐	
	• Water Depth (msl) m*	☐	
	• Proposed Total Depth (TD)	☐	
	• Estimated Workover Duration (days)	☐	
	• Anticipated Costs	☐	

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
10.	**Stimulation/Fraccing Operations**		
	• List of MSDS to be uploaded to NTDME website.	☐	
	• Fraccing Stages and Intervals included with Schematic.	☐	
	• Source of Water	☐	
	• Water Studies	☐	**Not recommended for approval if response is "No"**
	• Water Monitoring	☐	
	• Used Water Disposal Procedures	☐	**Is waste water to be trucked out? Provide name of Waste Water contractor and final delivery point.**
	• Pumped Volume of Fluid.	☐	
	• Estimated Return Volume of Fluid.	☐	
	• Information on Potable Water, i.e. depth to aquifer.	☐	
	• **Provide a well-labelled schematic showing minimum distance between the High Leak-Off case zone (Maximum Fracc Propagation) and lowest potable water aquifer.**	☐	**Not recommended for approval if response is "No"**
11.	Workover Rig/Stimulation Equipment Mobilisation Details	☐	
12.	Workover/Stimulation Results Summary	☐	
13.	Previous Workover/Stimulation Summary	☐	
14.	Workover/Stimulation Safety Considerations	☐	
15.	Workover/Stimulation Procedures (*Clear and Acceptable*?)	☐	If ***No***, please comment:
16.	Completion/Stimulation Procedures (*Clear and Acceptable*?)	☐	If ***No***, please comment:
	Completion String/Stimulation Equipment Diagram	☐	

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
	Proposed Downhole Schematic after Workover/Stimulation	☐	
17.	Workover Kill/Stimulation Fluid		
	• Type of Fluid	☐	
	• Calculations	☐	
	Well Assumptions Status	☐	**When was the integrity of the production casing validated?**
18.	Potential Workover/Stimulation Hazards.	☐	
19.	Materials List	☐	
20.	Well Deviation Data	☐	
21.	Proposed New Perforation Interval	☐	
22.	BOP Systems and Safety		
	• BOP Wellhead Diagram	☐	
	• Testing Procedures	☐	
	• Well Control Information	☐	
23.	Workover Rig/Stimulation Equipment Specification	☐	
24.	Schematic of Workover Operations Layout at the wellsite	☐	
25.	Environmental Management	☐	
26.	Workplace Health & Safety	☐	
27.	Risk Assessment Has the integrity of the production casing been validated?	☐	**Not recommended for approval if response is "No"**
28.	Contact List		
	• Operator	☐	
	• Contractors or Service Companies	☐	
29.	Reporting Arrangements (As per Part V, Division 2 and Part II, Division 4, Clauses 284 to 291 for Reporting in the *NT Schedule of Onshore Petroleum Exploration and Production Requirement 2012*).	☐ ☐	• **Part V, Division 2** • **Part II, Division 4**

No.	Key Items to Check	Please tick (√) or cross (X) the check boxes accordingly	Comments
30.	**Does the program contain triggers seeking the following Operational Approvals?** • Side Tracking? • Flaring?* • Testing? • Suspension or P & A	☐	**Not recommended for approval if response is "No"** *** For air drilling**
31.	NT Schedule of Onshore Petroleum Exploration and Production Requirement 2012		
	• Overall, the Workover Program satisfies and covers Part V, Division 1, Clauses 501 to 532 for Drilling and Workover.	☐	

1. INITIAL NTDME ASSESSMENT			
Assessor's Name:		Date:	
Assessor's Signature:			
2. SECOND NTDME ASSESSMENT			
Assessor's Name:		Date:	
Assessor's Signature:			
3. FINAL NTDME ASSESSMENT			
Assessor's Name:		Date:	
Assessor's Signature:			

8. DME Audit Checklists : Drilling; Environment; Fraccing; Well Testing
a) Site visit checklist: Drilling operations
b) Site visit checklist: Environment
c) Site visit checklist: Fraccing completion and testing operations
d) Site visit checklist: Well testing operations

Northern Territory Government
Department of Mines and Energy
Petroleum Operations

SITE VISIT DRILLING OPERATIONS CHECKLIST

Well Name: _____ **Permit:** _____

Operations/Activity: _____ **Operator:** _____

Rig Contractor: _____ **Rig Name:** _____

Visiting Officer/s: _____ **Date:** _____

Current Operations:

_____
_____
_____
_____
_____
_____
_____
_____

Planned Next 24 hours Operations:

_____
_____
_____
_____
_____
_____
_____
_____
_____
_____

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/ In-place? *Yes/No*	Comments
1.Rig Safety			
BOP System			
BOP Testing Schedule			
BOP Maintenance & Spares			
Well Control Procedures			Clear instructions displayed on rig floor?
Drills i.e. Kicks, Fire, Gas			Record of frequency kept?
Crew Training			
Safety Meetings			Safety Manual sighted?
Emergency Evac & Muster Points			Emergency Response Plan sighted?
General Signage			Person-in-Charge clearly displayed?
Effective Lighting			
Shut-In Procedures & Signage			Clearly displayed on rig floor?
Shut-In Rig Floor Equipment			
2. Drilling Operations			
Rig Breakdowns/Lost Times			
Accidents Lost Times			
Well Head Equipment			
Drilling Fluids and Solids Control			
Mud Pumps & Solids Control			
Mud Logging & Sampling			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/ In-place? *Yes/No*	Comments
Drilling Bits & BHAs			
Tubular Inspections			
Real Time Logging			
Wireline Logging & Formation Evaluation			
Casing			
Cement			
3. Production Testing Operations			
Monitoring & Measurement			
Flaring			
4. Drilling Operations Support			
Logistics			
Support Aircrafts			
Service Companies			
5. Overall Workplace Health & Safety			
Occupational Health & Safety			
Environmental			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/ In-place? *Yes/No*	Comments
6. Others			

General Comments:

Visiting Officers:

Name: _____

Signature: _____

Date: _____

Name: _____

Signature: _____

Date: _____

Northern Territory Government
Department of Mines and Energy
Petroleum Operations

SITE VISIT ENVIRONMENT CHECKLIST

Location: _____ **Permit:** _____

Operations/Activity: _____ **Date:** _____

Operator: _____ **Visiting Officer/s:** _____

Contractors: _____

** As per the Approved Environment Plan.*

Environment Risks as identified in the Approved Environmental Plan	**Are Risks* identified addressed on location?** *Yes/No*	**Are the Safeguards/ Management Methods* acceptable?** *Yes/No*	**Are the Monitoring and Reporting Strategies* effective?** *Yes/No*	**Comments**
Removal of native vegetation and potential fauna habitat. Loss of declared rare flora or priority species.		- Campsite chosen to minimise need for clearing. - Campsite no longer than 5 x 500 m. - Drill site no larger than 100 x 100 m. - No clearing of large trees. - Existing access tracks or oil seismic lines used whenever possible. - Access tracks avoid native fauna burrows and habitat. - No off-road driving.	- All incidents reported to wellsite representative and managed appropriately. - For incidents resulting in environmental harm, relevant government department notified in writing as soon as practicable.	
Disturbance to fauna, death or entrapment.		- Environmental induction of all staff to include information on potential fauna like to be in the area. - Limit vehicular activities to daylight hours when fauna are more visible and only drive at night if absolutely necessary or in the event of emergency. - Limit speeds on access tracks to 80km/h and 40km/h in difficult areas; 10 km/h on drill lease area. - Ensure vehicles are inspected and have working	- All incidents reported to PetroFrontier wellsite representative and managed appropriately. - For incidents resulting in environmental harm, relevant government department notified in writing as soon as practicable.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		lights and/or spot lights. - Visual Inspection of pits daily prior to operations commencing (or at shift change). - Awareness of fauna protection strategies highlighted at toolbox talks.		
Soil disturbance.		- Camp site, drill site and access track planned and implemented to avoid areas with high erosion potential. - Avoid creating windrows when constructing new tracks. - Avoid creating windrows when constructing new tracks. - Prepare drilling area relatively flat with shallow drains to guide water to the sump if rain occurs or when washing down. - Area to be levelled after completion of work and top soil replaced. - Topsoil and spoil stockpiled separately. - Stockpiles constructed with low profile to reduce erosion potential and to preserve seed bank. - Top soil replaced after project completion. - Implement dust-control measures (e.g. water spraying) if dust generation along access roads becomes a problem. - Sites rehabilitated as soon as practicable after the completion of drilling to minimise potential for erosion. - Remediation actions initiated if needed.	- Inspection either after first wet season or 1 year after decommissioning to assess soil disturbance/erosion.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
Disturbance to Indigenous or Heritage sites.		- Pre-construction assessment with follow up survey of sensitive sites by professional heritage and archaeologist already undertaken, and clearances administered. - LES to provide guidance for environmental aspects of site inductions. - Personnel trained in local environmental sensitivities during induction and camp sited to avoid known indigenous or heritage sites. - Continuing consultation with CLC. - No access to areas other than those cleared by CLC.	- Report to relevant authorities any artefacts found during drilling and road construction. - As determined by CLC and relevant authorities.	
Introduction of noxious weeds, exotic flora, vermin and animal diseases.		- Equipment cleaned and inspected for soil, plant material and pest animal contamination prior to arriving at site to minimise the risk of introducing exotic species. - Personnel trained/refreshed in need for hygiene management during induction. - Food scraps collected and disposed in animal pest proof bins. - Vehicles cleaned when leaving areas identified with weed infestations. - Imported materials to be locally sourced and weed free.		

Environment Risks as identified in the Approved Environmental Plan	**Are Risks* identified addressed on location?** *Yes/No*	**Are the Safeguards/ Management Methods* acceptable?** *Yes/No*	**Are the Monitoring and Reporting Strategies* effective?** *Yes/No*	**Comments**
Disruption of local traffic or inconvenience to local landholders, residents and other road users.		- Due to remote locations, traffic volume is likely to be minimal. - Station owners notified prior to creating tracks, driving on station, or accessing drill site. - Public notification of proposed timing and location of program and predicted disruptions to traffic. - Gates to be left as found.	-	
Grassfires and Bushfires.		- Induction to alert staff of smoking restrictions and fire hazards. - Diesel used in all vehicles - Adequate fire equipment located on-site and in vehicles. Personnel trained in its use. - Spark arresters fitted to vehicles. - Combustible materials cleared from the area surrounding the flare pit - Emergency response procedures followed as outlined in Emergency Preparedness and Response Plan.	-	
Fuel, Oil or Chemical Spills. Release of gaseous hydrocarbons to the atmosphere. Uncontrolled fire.		- Fuel, oil and chemical s segregated, labelled and bunded, as required. - Chemicals stored in self bunded trailers with roofs and walls. - Drill area/platform bunded. - Containers checked to ensure that they are in sound order.	- All oil spills to be recorded on Incident Report Form.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		- Drilling crew trained in the correct procedures for use of materials, including refuelling and clean-up procedures. - All operational personnel at the site will be instructed on the prevention of spills of fuels, oils and chemicals. - Drill sites are not located within sensitive environments. - Drilling not to proceed in riparian area to limit environmental risk to surface or groundwater - Drip trays used while refuelling. - Clean-up materials available in all relevant areas - Emergency response plan in place and personnel trained in its implementation. Emergency response drills conducted regularly and compliance with plan during an emergency.		
Overflow of drill cuttings or mud.		- Grade drill platform and construct shallow drains to direct drilling muds towards drill sump. - Sump constructed for the disposal of cuttings and associated muds. Sump to be fenced while left to dry - Sump lined to prevent contamination of soils with drilling chemicals and/or potential hydrocarbons. - Chemicals stored in self bunded trailers with roofs and walls - Water from drill muds allowed to evaporate.		

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		- Cuttings stay in sump (mud is biodegradable).). - In the event of a significant rain event, overflow will be managed by excavating additional sumps within lease area.		
Noise.		- General drilling areas have low population density so no major recommendations. - Contact landowners prior to accessing station tracks and working on drill sites. Provide landowners with contact details of PetroFrontier wellsite representative	- Maintain records of any complaints.	
Lighting		- General drilling areas have low population density so no major recommendations. - Rig not located within sensitive environments. - Unnecessary lights turned off particularly during insect plagues and yellow lights used where appropriate.	- Maintain records of any complaints.	
Visual Amenity		- General drilling areas have has low population density so no major recommendations.	-	
Dust.		- General drilling areas have has low population density. - Water to be used as a dust stabiliser, as required. - Contact landowners prior to accessing station tracks and working on drill sites. Provide landowners with contact details of PetroFrontier wellsite representative.	- Maintain records of any complaints or issues.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
Disturbance or damage due to infrastructure or services.		- Pre-drilling consultation with relevant utility authorities or land holder by the PetroFrontier well site representative and/or the Major Rig Manager for the early identification of the locations of existing overhead and buried cables, lines, pipes, water mains or other potentially affected infrastructure. - General areas have very low population density and are remote from high density populations so unlikely to have a high density of infrastructure and services. - Gates to be left as found. - Re-instatement of all fences and affected infrastructure to pre-drilling conditions as agreed with the relevant landowners.	- All incidents will be reported and managed through to resolution.	
Unapproved gas flaring.		- Combustible materials cleared from the area surrounding the flare pit. - Adequate fire equipment located on-site and personnel trained in its use. - Permits to flare for air drilling obtained within approval process for drilling the wells.	- All incidents will be reported and managed through to resolution. - Daily Reports showing gas volumes flared.	
Blowout during well testing or drilling. Gas ignites.		- Blow out preventer used during drilling operations from when the casing is set through to when the well is plugged and abandoned or when the well head is installed.	- Maintain records of - incidents - Report blowout incidents to DOR.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		- Blow out presenters turned on in the event of a blow out during well testing or drilling to seal off the well. - Emergency Preparedness and Response plan in place and emergency response drills conducted regularly.		
Release of waste oils or chemicals into the environment. Soil, surface water and groundwater contamination. Mortality of flora and fauna from soil, surface and groundwater contamination. Fauna drinking unsuitable water.		- Waste disposal not established within 100 m of surface water or within 3 m of ground water. - All waste material must be contained within designated areas - Water-based drilling cuttings and muds disposed to sump and allowed to evaporate (mud is biodegradable). Sump buried on site after all liquids have been evaporated. - Drilling mud sump fenced off following operations to prevent animals coming in contact with potentially contaminated muds and water. - Reuse drilling muds when possible. - Waste oils and chemicals labelled and stored appropriately for offsite disposal to licensed disposal sites by licensed waste management contractor. Pallets and oily waste not to be disposed of in landfill. - Waste compaction trailer on location and all solid waste will be compacted and taken to the Alice Springs dump. - Liquid waste (not including biodegradable mud) that	- Site inspected at conclusion of drilling. - Maintenance of mandatory waste records including date, quantity of waste removed & transported, type and any incidents that may have occurred en route.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		cannot go through the sewerage system will be stored in containers and transported to Hannons in Alice Springs. - Contaminated soils remediated on-site via land farming or bioremediation or removed from site for landfill disposal in consultation with the EPA.		
Release of grey water or sewerage into the environment. Soil, surface or groundwater contamination.		- On-site sewage treatment system in place. - Effluent from the STP discharged in accordance with EPA Water Recycling Guidelines allowing pasture/fodder irrigation via surface sprinkler or sub-soil irrigation. - Sewage sludge buried on-site covered with at least 250 mm of top soil and where practicable, located above known flood levels. - Grey-water friendly products used, where applicable.	- Waste contractor to maintain records of volumes, type of waste and dates of disposal / collection. - All incidents will be reported to PetroFrontier wellsite representative and managed appropriately. - For incidents resulting in environmental harm, EPA to be notified in writing as soon as practicable.	
Littering.		- • Landfill not established within 100 m of surface water or within 3 m of ground water. - • Food wastes disposed of in animal proof bins and/or skips. - • Solid wastes such as scrap wood, metal, packaging and litter segregated and stored in covered rubbish skips when necessary for offsite	- Waste contractor to maintain records of volumes, type of waste and dates of disposal/collection. - All incidents will be reported to PetroFrontier wellsite representative and	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		recycling or disposal to a licensed landfill (preferably by waste management contractor). - Regulated wastes such as waste mineral oils, tyres and batteries to be disposed of to a licensed treatment/disposal facility by a licensed waste contractor. - Any temporary landfill covered/screened to prevent material escaping from the landfill. - Landfill fenced to prevent cattle entering. - Landfill checked weekly to ensure that no material has been blown or washed out of the landfill. - Escaped waste to be returned to landfill and corrective actions implemented to prevent reoccurrence. - Program in place to minimise the volume of wastes generated, and to reuse and recycle where possible.	managed appropriately. - For incidents resulting in environmental harm, EPA to be notified in writing as soon as practicable	
Disturbed sites abandoned without required rehabilitation.		- Sumps and turkeys nest to be fenced following operations until they have dried. - All sumps filled in (after drilling cuttings have dried) - Plastic liners removed. - All equipment and rubbish taken off-site - Stockpiles redistributed in the order that it was taken out e.g. bed rock, sub-soil, top soil then vegetation.	- Continued monitoring of rehabilitated sites until completion criteria have been achieved or bonds returned by the NT Govt.	

Environment Risks as identified in the Approved Environmental Plan	Are Risks* identified addressed on location? *Yes/No*	Are the Safeguards/ Management Methods* acceptable? *Yes/No*	Are the Monitoring and Reporting Strategies* effective? *Yes/No*	Comments
		- Install drainage and erosion control features if necessary. - Deep rip compacted areas along the contour. - Continued rehabilitation until completion criteria achieved. - Check banks in drainage depression.		

Notes:

1. _____

2. _____

3. _____

4. _____

5. _____

Visiting Officer/s:

Name: _____

Signature: _____

Date: _____

Name: _____

Signature: _____

Date: _____

Northern Territory Government
Department of Mines and Energy
Petroleum Operations

SITE VISIT CHECKLIST: FRACCING, COMPLETION & TESTING OPERATIONS

Well Name: MacIntyre-2H **Permit:** EP127

Operations/Activity: _____ **Operator:** PetroFrontier

Contractor/s onsite: _____

Visiting Officer/s: _____ **Date:** _____

Current Operations:

_____
_____
_____
_____
_____
_____
_____
_____

Planned Next 24 hours Operations:

_____
_____
_____
_____
_____
_____
_____
_____

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted /In-place? *Yes/No*	Comments
1. Well Site Safety			
Safety Statement			
Site Induction			
Permit to Work System			
Well Control Procedures			
Site POB Board			
Safety Meetings (HSE)			
Emergency Evac. & Muster			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted /In-place? *Yes/No*	Comments
Points			
General Signage – Safety/Environment etc. i.e. Radio-active, PPE requirements.			
MSDSs			
Emergency Facilities and First-Aid Kits			
Spill Kits			
Lighting Plants			
Fire Extinguishers			
Emergency Shut-Down Procedures			
Emergency Shut-Down System and Equipment.			
2. Fraccing, Completion and Testing Equipment and Facilities ***Note:** This is in conjunction with the approved program for MacIntyre -2H Completion & Well Testing Program, Ver.13.1.*			
Coil Tubing Unit (CTU).			
Nitrogen System			
Cement Milling Equipment			
Surface Barriers for Fraccing, i.e. 6.5k Frac Tree, 10k Frac Head, CTU Isolation Valve, Frac Head Isolation Valves, HP Separator and High Pressure Treating lines.			
Chemicals and Treatment Sand.			
MSDSs for all chemicals onsite			
Frac Fluid Tanks			
Nitrogen Tanks			
Mixing Tanks			
Pumping Equipment			
Chemical Tracer Injection System			
Frac Gel			
Treating lines			
FRACCAT acquisition van.			
Lab in FRACCAT acquisition van.			
Record and Reporting System during Fraccing in the FRACCAT acquisition van.			
Surface Manifold			
Well Test Separator			
Flow lines to Separator			
Flare Stack and Ignition System.			
Hydrates Control System			
Filter Units			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted /In-place? *Yes/No*	Comments
Completion Tubing String			
BOP for Completion			
Gas Production Tree			
Slickline Equipment and Lubricator			
TWCV and BPV			

3. Pre-Fraccing, Pre-Completion and Pre-Testing

Note: *Various from the approved program for MacIntyre -2H Completion & Well Testing Program, Ver.13.1.*

Have all Pre-Checks been completed? • Results of GR/CCL/CBL/VDL logging OK? • Function testing of Fraccing Tree. • Pressure Testing of manifold, separator, treating and flow lines, connections, cross-overs, Well Testing package, CTU and Nitrogen System. • Surface Barriers pressure tested and chart recorded. • Function Test of Spectra Chem chemical tracer injection system. • JHAs completed • All lines secured • Function test all ESD stations • Fraccing, Completion and Testing Program made available and understood by all crew members. • All equipment working. • Pre-Flow Safety Meeting • Muster Horns tested • Responsibilities discussed • Review of Emergency Response Plan (ERP).			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted /In-place? *Yes/No*	Comments
4. General Workplace, Health, Safety & Environment			
General Occupational Health & Safety Standards			
Environmental Standards			
Flare Pit			
Sumps			
Dirt Pile			
Frac Ponds			
Workshop			
Shack			
Sand Storage			
Chemical Storage			
Gel Storage			
High Pressure Areas			
6. Others			

General Comments:

_____

_____

_____

_____

_____

_____

_____

Visiting Officers:

Name: _____

Signature: _____

Date: _____

Name: _____

Signature: _____

Date: _____

Northern Territory Government
Department of Mines and Energy
Petroleum Operations

SITE VISIT CHECKLIST: WELL TESTING OPERATIONS

Well Name: _____ **Permit:** _____

Operations/Activity: _____ **Operator:** _____

Well Testing Contractor/s: _____

Visiting Officer/s: _____ **Date:** _____

Current Operations:

_____
_____
_____
_____
_____
_____
_____

Planned Next 24 hours Operations:

_____
_____
_____
_____
_____
_____

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/In-place? *Yes/No*	Comments
1. Well Site Safety			
Safety Statement			
Site Induction			
Permit to Work System			
Well Control Procedures			
Site POB Board			
Safety Meetings (HSE)			
Emergency Evac. & Muster Points			
General Signage – Safety/Environment etc.			
Spill Kits in place.			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/In-place? *Yes/No*	Comments
Emergency Shut-Down Procedures			
Lighting			
Emergency Shut-Down System and Equipment.			
2. Well Test Equipment and Facilities *(**Note:** In conjunction with EPT Layout - Drawing No: SREHST1-PFD001)*			
Chemical Storage/Laydown			
Water Potable			
Tanker Load Out Facility			
Tank Farm (Storage Facility)			
Load Out Pumps			
Wellhead and associate rig-ups			
Multiphase Flow Meter (MPFM)			
Lighting Plant			
Gas Venting/Flaring System			
Choke (Adjustable/Fixed)			
Surface Safety Valve (SSV)			
Surface Flow Lines			
Produced Water Handling System			
Retention Tanks			
Pond			
Slickline Unit for Well Intervention			
Reservoir Fluid Sampling equipment			
Ports that allow monitoring of well stream parameters; i.e. temp. erosion, sampling etc.			
3. Pre-Well Test Checks			
Have all Pre-Well Test Checks been completed? • JHA completed • Adequate sampling bottles on site • All lines secured • Function test all ESD stations • Well Test Program made available and understood by all crew members. • All equipment working.			

Key Items to Check	Records Sighted? (if applicable) *Yes/No*	Accepted/In-place? *Yes/No*	Comments
4. Pre-Flow Preparation Test Checks			
Have all Pre-Well Test Checks been completed? • Pre-Flow Safety Meeting • Muster Horns tested • Responsibilities discussed • Review of ERP			
5. General Workplace Health, Safety & Environment			
Occupational Health & Safety			
Environmental			
6. Others			

General Comments:

Visiting Officers:

Name: _____

Signature: _____

Date: _____

Name: _____

Signature: _____

Date: _____

9. Guideline on Assessment Process for Onshore Petroleum Drilling, Workover and Simulation Application

Assessment Process for Onshore Petroleum Drilling, Workover and Stimulation Applications

Applicable Legislation: NT Petroleum Act 2011
NT Schedule of Onshore Petroleum Exploration and Production Requirements 2012

No.	STEP	REQUIREMENTS	ACTION BY
1.	Operator submits application (Project Application) to drill/workover/stimulate **NOTE:** 1. All applications are categorised as either Project Applications or Operational Applications. 2. All application letters must make direct reference to the applicable legislation, quoting appropriate clauses and signed by the custodian of the project. 3. Allow maximum of 30 days for processing of a Project Application 4. Operators are expected to provide **at least 5 days' notice** of an impending Operational Application. 5. *** Can be included in the Environment Plan**.	A. The application letter must be signed by the custodian of the project. B. The application needs to include: i. Drilling/Workover/Stimulation Program ii. Environment Plan iii. Safety Management Plan iv. Insurance Certificate(s) v. Oil Spill Contingency Plan vi. Emergency Response Plan vii. Bushfire Management Plan* viii. Erosion and Sediment Control Plan* ix. Weed Management Plan* x. Dust Management Plan* xi. Traffic Management Plan* xii. Biodiversity Management Plan* xiii. Waste Management Plan* xiv. Baseline Water Study xv. MSDS for Website xvi. Environment Rehabilitation Security Calculation Form xvii. Letters from Stakeholders, Cultural Clearances C. Before Approval: • Payment of Environment Rehabilitation Security. D. After Approval: • Environment Plan Summary to be submitted within 7 days of approval granted. **NOTE:** Please send all documents to: (a) directorenergy@nt.gov.au (b) petroleum.operations@nt.gov.au	Operator.
2.	**Send Environment Plan Guidelines and Operational Checklists to Operator.**	Operator provided with EP and Operational Checklists.	Petroleum Operations Team.
3.	Review of Application.	Email requesting comments.	Petroleum Operations Team.
4.	Request input from other NT Government Agencies like NRETAS or NTWorksafe.	Email requesting comments.	Petroleum Operations Team.
5.	Track Application assessment progress and review responses from other Agencies.	Track new versions using Work-In-Progress (W.I.P) tracker and refer responses back to the operator as required.	Petroleum Operations Team plus consultations with other NT Government Agencies.

No.	STEP	REQUIREMENTS	ACTION BY
6.	Prepare an Application Assessment Report.	Focussing on assessment and review of the application submission package, i.e. Program/Plans/Certificates.	Petroleum Operations Team.
7.	Environment Security estimated and agreed to be deposited.	Suitable security confirmed in place.	Operator/Petroleum Operations Team.
8.	Prepare approval letter for Director of Energy to sign.	Approval letter to be addressed to the custodian of the project.	Petroleum Operations Team.
9.	**Operator notified of approval and reminded to submit EP Summary within 7 days.**	Approval letter sent and W.I.P tracker updated accordingly.	Petroleum Operations Team.
10.	Well Integrity Compliance Checks and Drilling/Workover/Stimulation Progress Monitoring.	Set up new well integrity compliance spreadsheets for the well.	Petroleum Operations Team.
11.	Drilling Commences and EP Summary sent within 7 days.	Well Spudded. Dissemination of daily reports, e.g. DDR, DGR, Logs etc.	Operator.
12.	Operator submits application (Operational Application(s)) for approval while drilling/workover/stimulation progresses, e.g. Side-track, DST, P&A or Suspension.	a. Letter of application signed by the custodian of the project. **b. Work program must include current and final (after operational activity) schematics.** c. New Environment Plan (& Summary) or possible addendum or bridging document may be required. d. Other updated documents as required.	Operator.
13.	Assessment of the operational activities.	Assessment to focus on well integrity and safety of operations.	Petroleum Operations Team.
14.	Prepare Letter of Approval to carry out the operational activity for Director of Energy to sign.	Approval letter to be addressed to the custodian of the project.	Petroleum Operations Team.
15.	Drilling/Workover/Stimulation activity completed.	Update Petroleum Data spreadsheets with well information and data.	Petroleum Operations Team.
16.	Site clean-up and demobilisation of rig/workover/stimulation equipment	Complete site clean-up and demobilisation of all buildings, vehicles & equipment.	Operator.
17.	Monitor Environmental Rehabilitation progress.	Ensure environment is rehabilitated as per approved environment plan.	Petroleum Operations Team/Operator.
18.	Periodic Reporting of Environmental Rehabilitation	Reports required for monitoring environment rehabilitation progress.	Operator.
19.	Submission of Close-out Environmental Rehabilitation Report	Final confirmation that rehabilitation has been completed in accordance with the approved environment plan.	Operator.
20.	Assessment of Close-out Environmental Rehabilitation Report.	Assessment of final environment rehabilitation report before release of Environment Security Deposit.	Petroleum Operations Team/Independent Validator/Director of Energy.
21.	Release of Environment Security Deposit.	Security deposit released on acceptance that environment rehabilitation was undertaken as per approved environment plan.	Petroleum Operations Team.
22.	Submission of Well Completion/Workover/Stimulation Report and Data sets.	Well Completion Report/Workover/Stimulation and Data sets to be submitted to NTDoR.	Custodian of the project/Operator.

-END-

10. Guideline – Well Suspension Application

Well Suspensions

- Suspension applications are categorised as either "Drilling" or "Production".
    - A "Drilling Suspension" is one where the well is to be suspended **without** a downhole completion installed.
    - A "Production Suspension" is where the well is to be suspended **with** a downhole completion installed.
- The Northern Territory **does not** recognise "*Temporary Suspensions*" -- **ALL** suspensions are to include the installation and validation of a **minimum of two (2) permanent barriers.**

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1. Drilling Suspensions (without downhole completion installed)

- If the production casing is sealed to the formation, pressure tested and not perforated (and the cement integrity has been or is programmed to be logged), then this would constitute **one** permanent barrier.

2. Production Suspensions (with downhole completion installed)

- If the production casing is sealed to the formation, pressure tested and not perforated (and the cement integrity has been or is programmed to be logged), then this would constitute **one** permanent barrier.
- The installation and validation of a minimum of two (2) permanent mechanical barriers applies to **both tubing string AND annulus.**
- The wellbore schematic must be accompanied by a wellhead profile **CLEARLY** showing all wellhead barriers in **both the production tubing and annulus**.

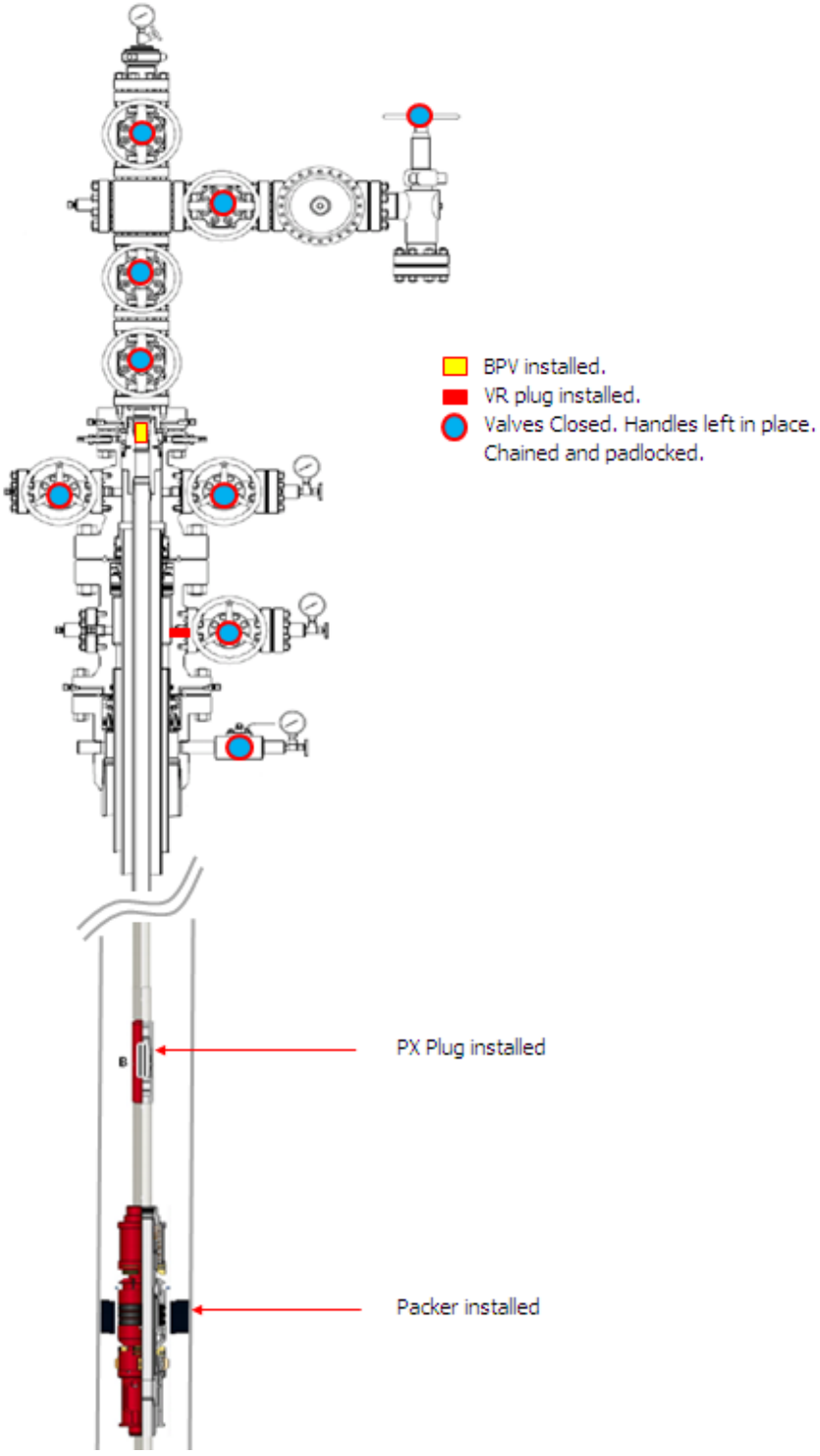
Applications for Suspension

Suspension applications are to consist of the following:

1. Letter of application, signed by the custodian of the project and making reference to Clause 528 of the Schedule of Onshore Petroleum Exploration and Production Requirements 2012.
2. Suspension Program reflecting the step by step procedures the rig will follow when installing and then validating the integrity of barriers (to be validated by either tagging or pressure testing).
3. Proposed final well schematic with all well construction features labelled, including the proposed position of installed barriers. The well's final brine weight is to be included. For Production Suspensions, a wellhead and downhole profile schematic with clearly marked permanent barriers is also to be included (*as attached Sample*).

Sample Diagram

Identifying all permanent barriers in the tubing, annulus and wellhead:



NOTE: **ALL BARRIERS ARE TO BE IDENTIFIED FOR:**

- **TUBING/DOWNHOLE**
- **ANNULUS**
- **WELLHEAD**

FOR WELL SUSPENSION ACTIVITY CLOSE-OUT

Please submit:

- Daily Drilling Reports to be sent as usual and reflecting the entire Suspension until activity close-out.
- The Final Well Schematic reflecting all well construction features (labelled) the position of ALL validated barriers and also the final brine weight.
- Photographs of the fenced-off well site with wellhead (valve handles removed or with handles left in place, chained and padlocked) along with signage reflecting contacts in the event of an emergency. At least 4 photographs will be required.

ADDITIONAL GUIDING INFORMATION

- Checklists and guidelines for various petroleum activities are available on the Department of Mines and Energy's website at: http://www.nt.gov.au/d/Minerals_Energy/
- Contact the **Petroleum Operations Team** on *petroleum.operations@nt.gov.au* for further information.

- END -

11. Guideline – Environment Rehabilitation Reporting

Environment Rehabilitation Reporting

Applicable Legislations: Part V, Division 2 of *NT Petroleum Act* and Clause 109 and 501 (o) of the *NT Schedule of Onshore Petroleum Exploration and Production Requirements 2012.*

Environment Rehabilitation Report:

The purpose of submitting this report is to document progress of the rehabilitation strategies as defined in the approved Environment Management Plan for a particular project or activity. The report is intended to inform Northern Territory Department of Mines and Energy (NTDME) of the environmental rehabilitation of impacted areas.

1. REQUIREMENTS

1. Final Environmental Audit

- **The audit must be conducted after a period of at least one wet season from completion of last activities.**
- The Final Environment Audit (audit) must be conducted by a nominated 3rd party auditor before submission of the Final Environment Rehabilitation Report to NTDME.
- The Final Environment Rehabilitation Report compiled after the audit must:
    - Provide clear evidence that the principles or aims of the environment management plan including the rehabilitation strategies have been addressed.
    - Assess the state of the environment in relation to the following:
        - Mobilisation and Demobilisation of Equipment
        - Disposal of Wastes
        - Removal of Equipment
        - Restoration of Infrastructure
        - Land Rehabilitation
        - Remedial Maintenance
        - Post Closure Monitoring

2. Report Submission

- Upon completion of the audit, a Final Environment Rehabilitation Report is required to be submitted to the Director of Energy within one calendar month.

3. Refund of Environment Rehabilitation Security Bond

- The Final Environment Rehabilitation Report will be assessed by NTDME. If clear evidence of adequate rehabilitation is demonstrated, the Rehabilitation Report will be accepted and the Project or Activity Environment Rehabilitation Security Bond refunded to the proponent.

- For further information on how the Security Bond is calculated, please follow link provided in "ADDITIONAL GUIDING INFORMATION" below to view the calculation template.

NOTE: THE ENVIRONMENT REHABILITATION SECURITY BOND CANNOT BE REFUNDED IF THE *FINAL ENVIRONMENT REHABILITATION REPORT* IDENTIFIES AREAS NEEDING CONTINUED MONITORING OR IF IMPACTED AREAS ARE NOT ADEQUATELY REHABILITATED.

2. CORRESPONDENCE

All correspondence concerning the environment rehabilitation report (*supporting documents, data, photographs etc.)* **should be in electronic format only** and emailed to:

DIRECTOR OF ENERGY

Attention: Team Leader Petroleum Operations

at: directorenergy@nt.gov.au and petroleum.operations@nt.gov.au

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ADDITIONAL GUIDING INFORMATION

- Checklists and guidelines for various petroleum activities are available on the Department of Mines and Energy's website at: http://www.nt.gov.au/d/Minerals_Energy/

- Contact the **Petroleum Operations Team** on *petroleum.operations@nt.gov.au* for further information.

- END -

12. Guideline –Chemical Disclosure Hydraulic Fracturing

DISCLOSURE OF CHEMICALS

The aim of this factsheet is to promote the safe and responsible use of chemicals used in hydraulic fracturing operations and to provide accurate and transparent information on any chemicals that may be used.

The use of chemicals in the petroleum industry is regulated by the Commonwealth and State Governments to ensure they are managed, stored, transported and disposed of in an effective, safe and environmentally responsible manner.

Why are chemicals used in hydraulic fracturing?

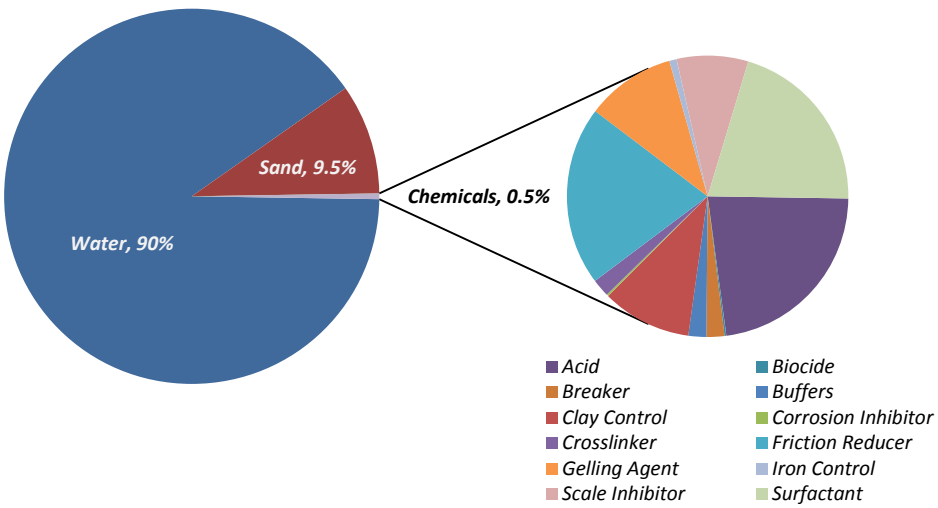
During hydraulic fracturing, fluid is pumped down a well at pressure to create fractures. These fractures or cracks generally vary between 20 and 40 m and are produced in gas-bearing rock formations that are located between two and five kilometres underground. This activity is carried out to provide the gas with a pathway through dense and impermeable rock that it would not normally be able to flow through.

The hydraulic fracturing fluid typically contains 90 per cent water, 9.5 per cent sand and up to 0.5 per cent chemicals.

Water is used to create pressure to fracture the rock. It is also used to transport sand and chemicals down the well and into the fractures. Sand is used to hold the created fractures open and hence retain an open pathway to increase the natural that can be extracted.

The hydraulic fracturing fluid is designed to serve a number of important purposes. Typically, particular chemicals are used to improve the transportation of sand, prevent the growth of bacteria, reduce mineral blockages and to prevent well corrosion over time.

TYPICAL FRAC FLUID COMPOSITION



How are chemicals assessed?

Petroleum companies are required to submit an application for assessment and seek approval before they can carry out hydraulic fracturing activities. The assessment process is carried out in accordance with NT legislation, in particular the NT Environment Regulations.

Petroleum companies must demonstrate that the use of all selected chemical will not pose an unacceptable risk to human health, the environment or groundwater resources. These assessments are carried out on a case-by-case basis.

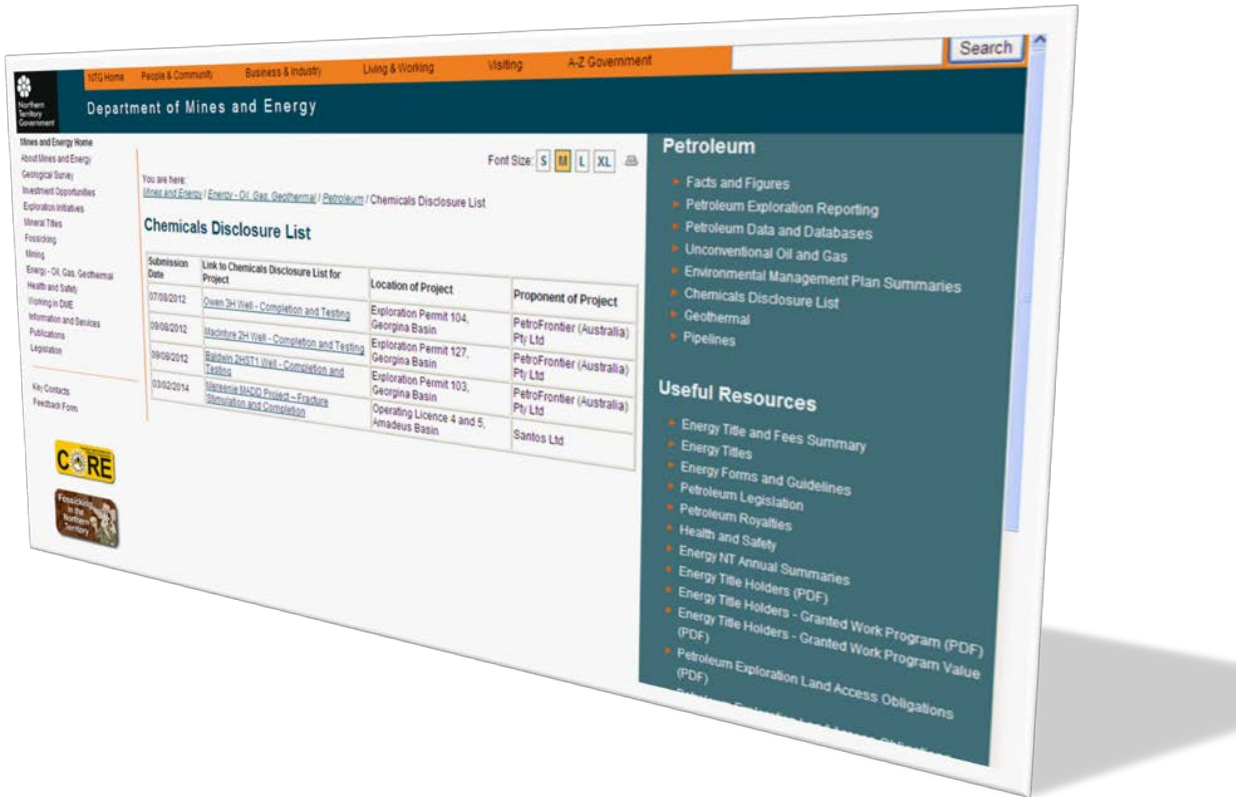
One of the preconditions for approval is that operators submit Material Safety Data Sheets (MSDS) for all chemicals that will be pumped down hole during the fracture stimulation. The MSDS must be made available for public disclosure (see below).

If the MSDS does not include the Chemical Abstracts Service (CAS) number, due to issues relating to proprietary protection or any other particular reason, then this CAS number must be disclosed to NTDME.

If significant risks or potential hazards or impacts are identified, the activity is referred to the NT Environment Protection Authority for an independent environmental assessment.

Where can I find what chemicals are being used for hydraulic fracturing activities?

The MSDS must be made available for public disclosure and are uploaded on NTDME's website. They can be found at the following link: *Mines and Energy / Energy - Oil, Gas, Geothermal / Petroleum / Chemicals Disclosure List.*



What types of chemicals are used for hydraulic fracturing activities?

The type of chemicals selected for use in the hydraulic fluid will depend on the properties of the rock in the target zone to be fractured.

Type of Chemical	Specific Use
Proppants	Proppants or tiny solids, usually sand, are used to physically hold the tiny rock fractures open providing the gas with an open pathway into the wellbore.
Microbial controls, biocides	Limits the growth of bacteria in fluids which may contribute to well corrosion or reduce flow rates.
Oxygen scavengers, corrosion inhibitors	Arrests or reduces corrosion rates by removing or deactivating oxygen and other corrosive materials in fluids.
Iron control, scale control	Limits the build-up of iron precipitates and mineral scale which can reduce the flow rate of fluids and contribute to well corrosion.
pH control, buffers, salts, stabilisers, solvents	Adjusts the chemical and physical properties of the fluid to achieve optimum flow rates.
Friction reducers	Reduces the friction forces of fluids to be pumped into the well in order to increase flow rates.
Clay inhibitors, stabilisers	Arrests clay swelling in the rock of the target zone to be fractured in order to optimise flow rates.
Gelling agents, binders, cross linkers	Increases the viscosity or thickness of fluids which allows more proppant to be carried into the rock fractures.
Breakers	Breaks down the gelling agents and releases the proppant into the rock fractures created.
Surfactants	Reduces the adhesive properties or stickiness of fluids in order to improve flow rates.

For further information:

Contact the Northern Territory Department of Mines and Energy's **Petroleum Operations Team** on petroleum.operations@nt.gov.au.

- END-

13. Sample DME Approval Letter

Northern Territory Government

DEPARTMENT OF
MINES AND ENERGY

www.nt.gov.au

EMAIL

TO: **Reuben Yagambaram**

COPY: **Matthew Howard; Alecia Wright**

FROM: **Annette Duncan**

DATE: **28 March 2014**

FILES: **C14.055.gp, E2014/0017, WH2014/0010**

PAGES: **1**

Santos Ltd's MADD Project - Application to Complete and Evaluate West Mereenie 19, OL4

Dear Mr. Yagambaram,

The Northern Territory Department of Mines and Energy (DME) has reviewed your application to complete and evaluate West Mereenie 19 (well) in OL4.

In accordance with the following clauses of the *NT Schedule of Onshore Petroleum Exploration and Production Requirements 2012*, I hereby grant approval to conduct the following activities:

- Clause 501 (1): To re-enter the well.
- Clause 526 (n): To swab the well.
- Clause 530: To complete the well.

The above approvals are to be carried out in accordance with the following documents:

- Activity Specific Environment Plan for Fracture Stimulation, Workover and Completion received by DME on 6 January 2014.
- The MADD Project Generic Program for Fracture and Completion received by DME on 18 February 2014.
- West Mereenie 19 Well Specific Details received by DME on 21 March 2014.
- Revised Application Letter dated and received by DME on 28 March 2014.

Please note the following:

- Clause 501 (5) of the *NT Schedule of Onshore Petroleum Exploration and Production Requirements 2012* states: **"An approved program shall not be varied without approval".**
- This communication represents approval to complete and evaluate **West Mereenie 19 only.** Applications seeking approval to carry out other operational activities, such as side tracking, abandoning, suspending etc., will need to be lodged as separate future applications.
- This approval does not cover any additional approvals that may be required from other agencies such as matters relating to occupational health and safety which are administered by NT WorkSafe.

This approval is valid for activities that commence within 3 months of the date of this letter.

If you have any further questions, please contact Gibson Porkime on 08 8999 7348 or email: petroleum.operations@nt.gov.au.

Annette Duncan
Director of Energy

28 March 2014

Department of Mines and Energy
Energy Directorate

Submission to Northern Territory Government – Public Inquiry into Hydraulic Fracturing