Santos
Submission #168 - Part 1

Scientific inquiry into hydraulic fracturing of onshore unconventional reservoirs and associated activities in the Northern Territory

Santos submission, April 2017

Santos

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FOREWORD

Santos welcomes the opportunity to provide this written submission to the Northern Territory Government's Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the Northern Territory.

With more than 60 years of finding, developing and producing natural gas throughout Australia, including decades of activity in the Northern Territory, Santos is better placed than most to help address the issues being considered by the Inquiry.

Indeed, Santos has hydraulically fractured more wells in Australia than any other oil and gas operator, though mainly in tight formations. However, the principles, practices and systems for safe and sustainable activities in shale resources are the same.

Santos also has a long and positive track record of working responsibly alongside local communities and other users of the land in a fair, open and cooperative manner.

This submission draws on our decades of this experience and goes into detail on many of the technical aspects of our business. It aims to address, in a comprehensive way, the issues and concern raised by the Inquiry Panel and members of the community.

Executive summary

Santos and the NT

Santos is a pioneer of natural gas exploration, development and production in Australia, with more than 60 years of experience, since its origins in the onshore Cooper Basin. Santos has a long history of petroleum activity in the Northern Territory (NT); the name 'Santos' is an acronym for 'South Australia Northern Territory Oil Search.' Santos has drilled has drilled over 4,000 onshore wells, of which 43 are in the NT.

Santos has hydraulically stimulated over 1,400 wells in South Australia, Queensland and the NT, involving more than 4,400 individual hydraulic stimulation stages. Santos has hydraulically stimulated 38 of the 44 conventional gas wells drilled in the NT's Amadeus Basin.

In 2011, shale gas exploration began in earnest in the NT, where unconventional resources are now estimated to be a several hundred trillion cubic feet gas in place. A lot more exploration and appraisal is required to fully determine the economic viability of this resource. The areas with the most promising shale gas potential, defined by recent well results, are limited to the McArthur Basin and in particular the Greater Beetaloo Basin.

In 2014, Santos drilled the Tanumbirini-1 exploration well, in EP 161, in the Greater Beetaloo Basin. The permit is limited to two pastoral leaseholders and is on native title land. The nearest Aboriginal community is 85 km from the well. The nearest town is Katherine, is 400 km away. The well identified the presence of a significant shale gas resource in the Velkerri shales. No hydraulic stimulation has yet been conducted although this is planned for the next phase of activity.

Hydraulic Fracturing

Hydraulic fracturing dates back to the late 1940s. It is not a new industry, and was first used in the NT in the 1967 (targeting conventional gas in vertical wells).

Last decade, the combination of technological advances in hydraulic fracturing and horizontal drilling unlocked unconventional gas in the United States (US) that saw shale gas jump from 1% of supply in 2000 to 25% by 2011 and 50% by 2015. Hydraulic fractured wells provided more than two-thirds of US natural gas production in 2015.

The so-called 'shale gale' has transformed the US economy, sending carbon emissions plunging (with gas replacing coal-fired electricity), stimulating jobs and local economies, and turning the nation from an energy importer to one that is not only self-sufficient but also a major exporter. It has also driven down domestic gas prices and stimulated new manufacturing.

In Alberta, Canada, hydraulic fracturing has been used to safely stimulate over 180,000 wells and over 10,000 wells have been drilled using horizontal drilling technology. Since 2013, over 80% of all producing oil and gas wells use horizontal drilling techniques.

Land access and the land rights of others

Well in advance of undertaking any activity on NT petroleum permits, Santos enters into discussions and ultimately access and compensation agreements with the relevant pastoral leaseholders and, through the Northern Land Council, the Traditional Owners. To date these agreements have only related to exploration.

Santos has a long and positive history of working collaboratively with Traditional Owners, landholders and leaseholders to ensure current and future uses of land are not negatively impacted. Compensation to pastoral leaseholders and freeholders is paid based on deprivation/impact to land, whilst traditional owners are compensated on a percentage of work program cost. By law, and our operational standards and practices, sacred sites are identified and avoided.

Under existing NT Government legislation, no petroleum activity can begin until an access agreement (and a compensation framework) has been reached with the landholder or leaseholder. There is also an independent arbitration process should an agreement not be reached. If an agreement is unable to be reached, there is no access. There is, therefore, no need for a landholder or leaseholder to have a right of veto.

If government wants to provide a portion of its petroleum production royalty receipts to landholders and/or leaseholders, that is its prerogative, although we note it would be inconsistent with the principle that the rights to the resources in the ground are held by the Crown, and in the NT context, for the benefit of all Territorians. By way of example, the majority of Santos' area of project interest in the Greater Beetaloo Basin, within EP 161, is covered by a single pastoral leaseholder, a foreign-owned entity. It would seem counter-rational if a partial revenue stream flowed from a government-derived royalty share of oil and gas sales to an offshore vehicle. Regardless, oil and gas companies should not be asked to bear this additional cost.

Santos McArthur Basin Development Scenario

Whilst very early days, and as requested by the Inquiry Panel, Santos has developed a hypothetical, though indicative (in terms of scale), development scenario that anticipates between 300 and 350 production wells over 30 years. It is likely that between 4 to 10 horizontal wells will radiate from centralized surface pad locations significantly reducing the environmental footprint of development by also minimizing the number of access tracks and locations of vehicle movements.

Economic Opportunity

The economic contribution of oil and gas activities, from the exploration phase through to appraisal, development and production, can be significant for the local community, the region, the state and the nation. A Deloitte Access Economics Report into the economic contribution of Santos' South Australian operations showed that in 2014, the company's activities were estimated to have contributed around $1,445 million in value added to the state economy. Santos' contribution to the national economy was estimated at $1,592 million in 2014. The demand generated by Santos' South Australian operations in 2014 was estimated to have added around 2,724 and 3,422 full-time jobs to the state and national workforces respectively.

The Santos-operated GLNG project in Queensland is another good example of the positive economic impact flowing from oil and gas investment. Since January 2011, GLNG has purchased materials and services totalling approximately $16 billion. Of this, more than $8 billion has been invested in Queensland, with more than $1 billion in regional areas. Community investment, particularly in infrastructure such as roads, airports and medical services has been significant.

Well Integrity

Well integrity (keeping hydrocarbons, hydraulic fracturing fluids and produced water in the well, contained by steel and cement barriers) is the key to a safe and sustainable industry. To achieve this, leading practice in planning, design, procurement, testing and construction is critical. On-going monitoring and inspections, and remediation actions if required, will result in a very low probability of well integrity failure.

A well barrier issue, or failure, does not necessarily mean a loss of integrity i.e. the outward flow of hydrocarbons or fluids from the well to the surrounding environment or geological formation. Typically, the purpose of monitoring is to identify if a single barrier issue occurs, which acts as a warning sign that corrective or further preventative action is required whilst well integrity remains. Santos has a well integrity management plan and associated risk level matrix which dictates the level of action required.

Santos production wells have a minimum of two barriers to near-surface aquifers. International experience demonstrates that a loss of well integrity is rare. For example, the data from 253,090 production wells in Texas found that only four in every 100,000 (0.004%) wells constructed to modern standards experienced a loss of well integrity; this compared to 0.2% for older wells.

Similarly, new design standards and well integrity management systems were introduced at Santos in 1992. Since then, there have been no incidents involving a loss of well integrity (0% of 1,736 wells) in the Cooper Basin.

Santos performs monitoring and inspection activity during the construction, operation and decommissioning phases of all petroleum wells.

Santos supports the enabling of best practice for constructing and decommissioning of shale gas wells. This may be based on the Queensland Code of Practice for petroleum wells, which is drawn from international standards and best practice guidelines. Santos took the lead on industry consultation with the Queensland Department of Natural Resources and Mines when this Code was being developed.

According to the Queensland GasFields Commission: “The ultimate cementing ‘failure’ rate after testing, remediation, and follow-up according to the Code has thus been 0%. The likelihood and therefore risk of a subsurface breach of well integrity is thus assessed to be very low to near zero”.

Fracture Propagation

Fracture height growth has been extensively measured using micro-seismic monitoring in the US and Cooper Basin. This shows the average height growth to be around 100 metres, with a maximum of 300 – 350m. No evidence of hydraulic fracture growth into shallow aquifers during shale stimulation has been recorded. Given the geomechanical properties and stress state of the prospective shale in the Greater Beetaloo Basin, fracture propagation is expected to be confined to the target intervals. Moreover, the separation between the target intervals and the groundwater aquifers is significant (>1500m) and consequently the potential risk of fracture propagation into groundwater aquifers is considered to be negligible.

Water

The prospective shale formation in the McArthur Basin is located on average more than 1500m below the regionally important limestone, or Tindal, aquifer. The risk of vertical fracture propagation over this distance to the aquifer is considered to be effectively zero.

Layers of engineered and specialist cement and steel casing are a barrier to interaction where the well intersects the shallow aquifer. A well integrity management systems manages this risk for the life of the well. The final decommissioning of the well is engineered to equivalent standards with the use of specialist equipment and materials used.

Santos supports the need for baseline monitoring of water resources. Baseline water bore assessments have already been conducted in proximity to drilling activities in EP 161. Baseline water bore assessment will be completed for bores in proximity to future activities. This would include water bores within a 2km radius of hydraulic fracturing activities.

Resource companies actively exploring in the Beetaloo Basin in the NT (including Santos) are entering into an agreement with the Commonwealth Scientific and Industrial Research Organisation (CSIRO) to establish a coordinated research and parametric approach into the methods and establishment of baseline values of groundwater. The work program is intended to understand and quantify the baseline levels of gas and water quality within the study area. The study area will centre on the permits currently held by the resource companies (including Santos) in the Beetaloo Basin area and include sufficient area around these permits to apply a more regional understanding of groundwater, including water quality.

Water use and management

The water requirements for drilling and hydraulic fracturing are relatively small compared to other industrial and agricultural users in the Territory. Technological advances now allow the use of poorer quality water (non-potable quality) for making up hydraulic stimulation fluids. This facilitates options for the potential re-use or recycling of fluids and/or the blending of difference water sources.

Based on the indicative Santos development scenario prepared for the purpose of this submission, the total water demand for well pad construction, drilling and hydraulic fracturing is approximately 5.5GL (assumes 50% flowback recycling) to 11 GL (no recycling) over 30 years. This equates to an average of approximately 183ML/year to 367ML/year respectively. This compares to an estimated 4,380ML/year to 5,475 ML/year for stock use in the Greater Beetaloo Basin(calculated by applying an average consumption rate of 50 litres/head/day).

Waste water

During exploration, waste water volumes are minor and are transported to licenced waste disposal facilities. Should development proceed, waste management, treatment and recycling facilities will be installed. Typically, these comprise modular and transportable treatment facilities with waste water storages either constructed as partially in-ground turkey nest ponds or above ground tanks.

Ponds and tank storages are engineered and constructed with materials designed to contain the contents within the structure. Ponds are typically constructed with compacted a clay layer over laid with UV stabilised HDPE liners. Seepage monitoring is typically installed. Tanks are typically constructed with multiple layers of UV stabilise HDPE. The tanks are placed on a compacted hardstand area.

Any residual wastes will be disposed of in accordance with legislative and regulatory requirements at appropriated licenced waste management and disposal facilities.

Induced seismicity

Induced seismicity, where significant seismic events are generated as a result of hydraulic fracturing, is extremely rare. Globally, three instances have occurred where critically stressed faults are interpreted to have been activated by hydraulic fracturing resulting in “felt” seismic events (interpreted failure of the faults catalysed by fracturing). The risk can be mitigated by a thorough understanding of the subsurface faulting and structure (e.g. through 3D seismic) and the stress regime. Seismic monitoring stations are under consideration to establish a baseline of seismic activity.

Chemical Use

In Queensland, Santos makes public its chemical risk assessment reports, which are based on best practice Australian and international guidance, methodologies and risk assessment tools. This includes the disclosure of hydraulic fracturing chemicals. The reports assess the persistence, bioaccumulation and toxicity of individual chemicals, geogenic compounds in flowback water and the total fluid mixture. The reports also cover the full lifecycle of the chemicals – transport, storage, mixing, injection, flowback, reuse, recycling and disposal.

Management controls focus on reducing both the likelihood of release and the magnitude (volume) should a release occur. With such management controls in place, surface spills pose a low risk to environmental receptors and any impact would be localised, discrete and readily addressed.

Baseline bore assessments are undertaken within and in proximity to activities. For example, Santos GLNG has undertaken 792 baseline bore assessments within its tenements. Further monitoring is undertaken for bores located within a 2km radius of hydraulic fracturing activities.

Public concern about chemical use is reduced by a transparent, full disclosure policy. Santos supports the disclosure of chemical additives and submission of chemical risk assessments for hydraulic fracturing to Government. Santos also supports the public disclosure of chemical additives by Government. Consideration, however, should be given to ensuring that the regulatory framework supports further innovation and investment in technology in this area.

Fugitive Emissions

Research undertaken by the CSIRO in 2014 on 43 CSG production wells in QLD identified a leakage mean emission rate of 0.02% of production (3.2 g/min). To put this in perspective, given there are over two million head of cattle in the Northern Territory, each producing on average 0.11g/min, then there would need to be over 71,000 of these wells operating in any year to equal the same rate of emissions as the cattle.

A recent publication by the National Energy Technology Laboratory and Carnegie Mellon University Pittsburgh has quantified emissions in the US from extraction to delivery (full supply chain) at 1.7% of production (JA. Littlefield et al. 2017). This reasonably compares to the US EPA's Green House Gas Inventory of the Natural Gas Sector (EPA 2016) when divided by the production volume (1.4% of production).

To quantify Australian emissions, CSIRO scientists, through the Gas Industry Social & Environmental Research Alliance (GISERA), are currently undertaking further research into quantifying lifecycle methane emissions including understanding the natural or background emissions of methane. This research will include all natural gas activities and associated infrastructure.

Santos is in the planning phase of baseline methane monitoring within the Beetaloo Basin and surrounding areas. At this stage is anticipated that this baseline assessment will be undertaken by CSIRO scientists.

There is a commercial imperative, as well as an environmental one, in keeping gas in the pipe.

Environmental Setting

The prospective area in EP161 predominantly lies within Roper Gulf Local Government Area, with a small area in the southern portion lying within Barkly Local Government Area. The prospective area is located in the Beetaloo Basin, within the greater McArthur Basin. Land use within the target area of EP161 is pastoral. Two perpetual pastoral leases (landholders) account for 100% of the prospective area with cattle grazing native vegetation representing the principal pastoral activity.

Due to the dispersed and small nature and scale of the disturbance footprint associated with both potential exploration and a hypothetical development scenarios, no threatened species or species habitat are considered likely to be significantly impacted by the proposed activities. There are no national parks or areas of conservation within or adjacent to the prospective area.

Santos will undertake baseline monitoring to confirm baseline environmental values. These will be used to support regulatory approvals and to inform design, modelling and management practices. Baseline studies are to occur for ecology, soils, air quality and noise

Noise and amenity

Given the remote nature of the Beetaloo Basin and EP161, the potential for noise and amenity impacts are also remote and unlikely. For wells, the generation of noise is limited to the time taken to drill and hydraulically fracture the well or a group of wells at a multi-well pad. Potential impacts to pastoral leaseholder activities are managed through planning – by understanding the operations and timing of pastoral activities and open two way conversations.

Noise and amenity impacts from camps and facilities can be effectively be managed through planning and location selection – with an aim of avoiding and then minimising the potential risk. Engineering controls and equipment selection can also be utilised to further mitigate noise levels if required.

Securities and Bonds

NT law requires a security for potential environmental liabilities. The NT Government has an existing security calculator and guidance in place for the calculation of the amount of the security.

The potential for future risks or liabilities can be effectively managed through clearly defined regulatory rehabilitation objectives and outcomes, as well as the adoption and implementation of an appropriate code for well decommissioning.

Road Safety

Road safety is a key focus for our business. Indeed, driving is the biggest risk to the health and safety of our people in the field, who travel millions of kilometres each year on regional and remote roads. For example, Santos has a driver management framework in place to ensure our employees and contractors maintain high standards of road safety at all times – for their own safety and that of others in the community.

A key part of this framework is the in-vehicle monitoring system, or IVMS, which is installed in all Santos and contractor vehicles. The IVMS uses a GPS network to automatically track, collate and analyse data to build a centralised real-time picture of each individual's driving behaviour on the road. On top of the basics of road safety – such as speed and use of seatbelts – the IVMS tracks additional requirements such as using only roads that we have approval to use, not driving for long periods without rest, avoiding situations requiring heavy braking, keeping to low speeds on private properties and engaging 4WD when driving on unsealed roads.

A recognition and reward system is in place to encourage good performance; likewise any breaches trigger an immediate notification to the individual and their manager to encourage compliance. Within a year of its introduction in Queensland in January 2013 as one example, the driver management framework improved safe driving performance by 80%, and has been maintained at that level since. Other safety initiatives are also ongoing, such as Santos' reverse parking policy.

Regulation

The environmental risks associated with hydraulic fracturing can be managed effectively by best practice operating standards and management systems, and a robust regulatory regime.

Changes resulting from the Hawke review have addressed many of the previous regulatory shortcomings, and is considered fit for purpose for exploration and appraisal activities.

1.0 Introduction

Santos Limited (Santos) is planning to continue exploration of prospective shale gas resources within the McArthur Basin/Greater Beetaloo Basin in the Northern Territory (NT) under the authority of onshore petroleum exploration tenements granted by the NT Government.

The economic production of shale gas requires hydraulic fracturing to produce at commercial rates from the low-permeability shale formations. Without hydraulic fracturing to confirm the feasibility of production and understand environmental conditions and economic realities, the potential benefits of commercial gas supply will not be realised.

While the exploitation of shale gas is relatively new to Australia and the NT, exploration and production is now well established in the US where the production of shale gas has had a profound impact on the US economy. Moreover, many of the technologies used in the exploitation of shale resources have been used in Australia for many years to produce gas from tight formations.

It is Santos' intent to work with the NT Government, local communities, traditional owners, landholders and businesses in order to safely and responsibly develop shale gas resources within the NT. Santos welcomes the opportunity to provide this submission in response to the Terms of Reference of the independent Scientific Inquiry into Hydraulic Fracturing of Onshore Unconventional Reservoirs and Associated Activities in the NT (the Inquiry).

According to the Terms of Reference (NT Government, 2016), the Inquiry will:

1. Assess the scientific evidence to determine the nature and extent of the environmental impacts and risks, including the cumulative impacts and risks, associated with hydraulic fracturing of unconventional reservoirs and the associated activities in the Northern Territory.
2. Advise on the nature of any knowledge gaps and additional work or research that is required to make the determination in Item 1, including a program for how such work or research should be prioritised and implemented, that includes (but is not limited to)
    a) Baseline surface water and groundwater studies,
    b) Baseline fugitive emissions data,
    c) Geological and fault line mapping, and
    d) Focus areas for baseline health impact assessment.
3. For every environmental risk and impact that is identified in Item 1, advise the level of environmental impact and risk that would be considered acceptable in the Northern Territory context.
4. For every environmental risk and impact that is identified in Item 1
    a) Describe methods, standards or strategies that can be used to reduce the impact or risk; and
    b) Advise whether such methods, standards or strategies can effectively and efficiently reduce the impact or risk to the levels described in Item 3.
5. Identify any scientific, technical, policy or regulatory requirements or resources that are in addition to the reforms being implemented through the existing environmental reform process that are necessary to reduce environmental risks and impacts associated with the hydraulic fracturing of unconventional reservoirs to acceptable levels.
6. Identify priority areas for no go zones.

As per the Terms of Reference, hydraulic fracturing and associated activities are defined as the process of injecting a fluid comprised of water, chemicals and proppant at high enough pressures to fracture a gas bearing formation (further discussed in Section 3.2 of this submission). This submission considers the hydraulic fracturing activity as well as the following associated activities:

- Acquisition of ground or surface water for hydraulic fracturing
- Mixing of water, chemicals and proppant to create hydraulic fracturing fluid

- Return of injected fluid and water produced from the unconventional reservoir to the surface after hydraulic fracturing, and subsequent transport for reuse, treatment or disposal
- Reuse, treatment and disposal of wastewater generated by hydraulic fracturing.

This submission responds to the Inquiry's Terms of Reference and the risk themes identified in the Background and Issues Paper (NT Government, 2017). Santos has drawn focus to those activities that present challenges for the shared understanding of shale gas industry and landholders, traditional owners, communities and the NT Government. It draws on available domestic and international evidence to demonstrate how the potential impacts of hydraulic fracturing can be effectively managed and mitigated and verified through monitoring. The key issues discussed in this submission are outlined in Table 1.

Table 1 Submission outline

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2.0 Who is Santos

Santos is a leading Australian gas exploration and production company with activities in every major petroleum province in the nation and more than 60 years of experience of finding and producing natural gas, working responsibly and sustainably alongside other users of the land and sea.

Santos has one of the largest exploration and production acreages in Australia, and also has interests overseas (including Indonesia and Papua New Guinea) and supplying energy to homes, businesses and industries across the region. Santos' projects are based on safe, sustainable practices conducted in partnership with landholders, communities, all levels of government, regulators and business partners.

In Australia, Santos has activities focused on unconventional oil and gas in five onshore basins – the Surat and Bowen Basins in Queensland, the Cooper Basin in South Australia (SA) and Queensland, the Gunnedah Basin in New South Wales (NSW), and the McArthur Basin in the NT. This includes natural gas from coal seams (coal seam gas, or CSG), natural gas from shale formations (shale gas), and natural gas from low-porosity sandstones (tight gas).

Santos has an enduring presence in the NT through major interests in onshore and offshore oil and gas assets. The name "Santos" is an acronym for "South Australia Northern Territory Oil Search". It is a foundation joint venture partner, and the only Australian company, in the Darwin Liquefied Natural Gas project (DLNG), and for many years was the mainly supplier of domestic gas to NT, from the Mereenie (conventional gas) facility and fields west of Alice Springs. Santos has been a strong supporter of the NT community over the years, partnering with Darwin Festival, Somerville Community Services, Operation Flinders and, through the DLNG joint venture, the West Arnhem Land Fire Abatement Project.

In over 60 years of petroleum activities, Santos has drilled over 4,000 onshore wells, of which 43 are in the NT.

Hydraulic stimulation activities are not new to Santos, nor the industry. The practice was first employed by Santos in the late 1960s, and has been used consistently since the early 1980s to enhance oil and gas recovery.

To date, Santos has hydraulically stimulated over 1,400 wells in SA, Queensland and the NT, with over 4,400 individual hydraulic stimulation stages undertaken. Santos has hydraulically stimulated 38 of the 44 conventional gas wells in the NT's Amadeus Basin (Mereenie field), including four in 2014.

As part of exploration in the NT's McArthur Basin, the company has plans to hydraulically stimulate the Tanumbirini 1 exploration well located on EP 161, which was drilled in 2014.

As such, Santos is well positioned to provide views to this Inquiry.

3.0 What is shale gas

Shale gas is primarily methane trapped within shale rock layers at depths greater than about 1,500 metres (m) (CSIRO, 2015). Shale gas occurs within rock formations, under high confining pressure, which have low porosity (proportion of volume consisting of pore spaces) and negligible permeability (ability to transmit a fluid through connecting pore spaces). These properties restrict the natural flow of gas within or from the shale. Hydraulic fracturing is (always) used in shale gas wells to increase the flow of gas from the shale reservoir (CSIRO, 2015).

3.1 Natural shale gas formation

Shales were originally deposited as laterally extensive, organic-rich muds and silts in anoxic or sub-oxic environments on a sea or lake floor. On burial, and under conditions of increasing pressure and temperature, the organic material is transformed into organic derivatives (‘kerogen’) and, under increasing temperature and pressure hydrocarbons are generated. A first phase of oil generation and expulsion may be succeeded at higher temperatures by gas generation resulting from the ‘cracking’ of long chain hydrocarbons and kerogen.

Key features of shale gas and shale oil reservoir rocks include:

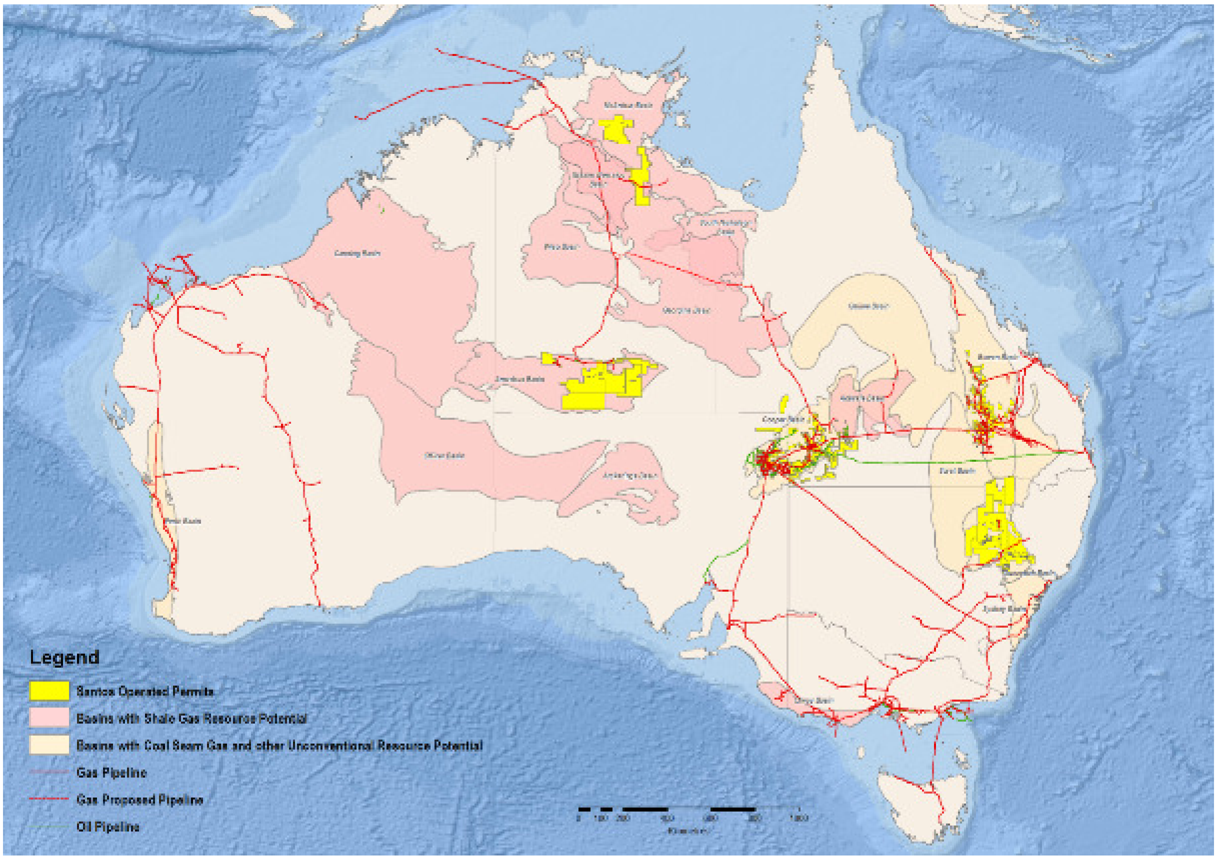
- Diverse, often interbedded, fine-grained rock types such as siltstone, limestone, dolomite, mudstone; rarely true shale (defined in its original stratigraphic sense as ‘fissile mudrock’).
- Significant amount of thermally matured organic matter.
- Low permeability (less than 0.1millidarcy (mD)).
- Tens to hundreds of metres thick.
- Significant fraction of generated hydrocarbons retained within microscopic pores and fractures in the source rock or in adjacent low permeability layers.

Shale gas exploitation targets these un-expelled hydrocarbons.

3.1.1 Shale gas resources in Australia

Australia comprises a number of sedimentary basins, particularly in northern, central and western Australia, which are prospective for shale gas, based on the abundance of shale, their likely maturity and their total organic carbon content (ACOLA, 2013). Indicative shale gas resources and Santos' petroleum interests across Australia are shown in Figure 1.

Figure 1 Shale gas resources and Santos petroleum interests in Australia



Source: (Santos, 2017)

Although Australia has potentially vast resources of shale gas, the industry is largely in exploration phase (CSIRO, 2015). In the NT, the Proterozoic McArthur Basin contains a number of formations and sub basins that are considered prospective. The Greater Beetaloo Basin and associated sub basins are ranked amongst the top six basins in Australia in terms of composite play success and prospective area success (Norton Rose Fulbright, 2015). The Beetaloo Basin is Santos' focus with regards to shale gas exploration – and the area of prospective shale interest within this basin is the focal point of this submission.

3.1.2 Shale gas composition

In shale gas, like all natural gas, the composition gas can vary depending on the source material for the hydrocarbons, burial conditions (temperature and pressure), sediment composition and other geological influences such as volcanic activity.

There have been a limited number of wells drilled in the McArthur Basin (and the Beetaloo Basin) to date, and thus a limited compositional data set available. Origin Energy Limited (Origin) confirmed the discovery of hydrocarbons in the Beetaloo Basin (Origin exploration bore Amungee NW-1H) that indicates the shale gas from the reservoir is a dry gas (limited potential for shale oil) comprising 92-95% methane, 1-3% longer chain hydrocarbons (ethane, pentane, etc.) and 2-4% carbon dioxide (CO_{2}) (Origin Energy, 2016) (Santos, 2017).

Based on this analysis of the produced gas, it is considered that limited processing would be required to meet transmission pipeline gas specifications. There is currently no information available on trace constituents present in shale gas in the NT (Santos, 2017),. Natural gas can contain variable and trace amounts of:

- Non-hydrocarbon inert components such as carbon dioxide, nitrogen, helium, argon and sulphur compounds such as hydrogen sulfides, mercaptans (methanethiol) and alkyl sulphides
- Naturally occurring radioactive materials (NORM) (e.g. radium, radon, thorium)

- Heavy metals such as mercury, antimony, arsenic, beryllium, cadmium, cobalt, copper, lead, nickel, selenium, vanadium and zinc
- Aromatic hydrocarbons (benzene, toluene, ethyl-benzene and xylene (BTEX) and polycyclic aromatic hydrocarbons (PAH)) (IESC, 2014).

3.2 Production of shale gas

Shale gas production typically uses horizontal drilling and hydraulic fracturing techniques to release gas trapped in shale formations due to its low permeability (US Department of Energy, 2013). Both horizontal drilling and hydraulic fracturing are among the practices that have become more widely used over the past two decades to enable access to vast new natural gas resources contained in shale deposits across the US (Kargbo, Willhelm, & Campbell, 2010), (Mooney, 2011). Hydraulic fracturing is also used, within horizontal and vertical well bores in the renewable (geothermal) energy industry and to increase the flow rate of groundwater supply bores (APPEA, 2016).

Horizontal drilling and hydraulic fracturing are part of a broader development cycle. Generally, commercial development of a shale gas resource occurs incrementally. The development cycle for a prospective area includes exploration, appraisal, production well and infrastructure construction, production operations, and then decommissioning. Rehabilitation occur both post development (areas not required for operations) and then post operations. This section provides an introduction to the development cycle for shale gas, including exploration and appraisal, well construction, hydraulic fracturing (as defined in the Inquiry's Terms of Reference (NT Government, 2016)) and rehabilitation.

3.2.1 Exploration and appraisal

Exploration involves the search for a particular set of geological conditions likely to result in natural gas resources that can be economically extracted. It begins with a review of published materials and geophysical surveys to identify locations for exploratory drilling that best represent the geological formation(s) of interest within known constraints such as tenure boundaries, topography and environmental sensitivities.

Further geological and/or geophysical surveys such as seismic surveys are conducted to characterise subsurface geology and structural features such as depth, inclination, orientation and faults within the target shale. Seismic surveys are shown in Figure 2.

Figure 2 Examples of seismic survey

Exploration core holes are then drilled to collect shale and rock samples for testing. At the end of exploration phase, core holes may be decommissioned or converted into wells if field development progresses into appraisal and production phases.

The hydraulic fracturing and testing of the prospective interval will be critical in determining the commercial potential of a play (shale gas development opportunity). In the exploration phase, hydraulic fracturing and testing may be conducted in a vertical or horizontal well. Gas produced during the exploration phase is collected and flared as pipeline infrastructure is not normally accessible to provide a transport route.

With positive indications from testing, the shale play may move into the appraisal and development phases, while exploration activity will continue to gather information to assess the broader regional prospectivity.

Where testing confirms that a shale formation has the potential to produce gas, appraisal wells are drilled to quantify the size and nature of the gas resource. The appraisal process is a pilot test i.e. a small scale trial comprising production wells with supporting gas and waste management facilities installed. Gas produced during the appraisal phase is normally flared as pipeline infrastructure is not normally accessible to provide a transport route.

From the appraisal phase, operators aim to get an understanding of the production profile that can be expected from newly drilled and hydraulic stimulated wells in future (i.e. production rate with time and total production volume over the life of the well). This information is primarily derived from extended production tests (e.g. 90 day or longer gas flows) conducted during the appraisal phase.

Well productivity information is required to optimally size the production facilities and processes, as well as provide data used in defining optimum downhole well spacing. The maximum number of wells per well lease is a function of formation target depth and the downhole well spacing; this subsequently dictates the number, frequency and size of the well lease at the surface.

Information gathered on gas composition is used to identify appropriate materials for construction of wells and process facilities, as well as the processing steps required to refine and transport the gas for sale to market.

Operators will form an optimised well field concept and fracture stimulation designs during the appraisal phase, but this will be continually optimised throughout the development phase as more information on geology and flow results are obtained.

If the appraisal process indicates that commercial quantities of gas can be produced economically, an optimal development scenario for full scale production can be planned and designed using information gathered during exploration and appraisal stages, including gas quality, volumes and flow rates.

Further detailed information on Santos' recent and planned exploration activities in tenements in NT is provided in Section 4.3.

3.2.2 Well construction

Drilling occurs after petroleum engineers and geologists believe economical hydrocarbon reserves may be found and the project is sanctioned. The actual drilling location is selected based on proximity to the subsurface target location and environmental and cultural heritage assessments are undertaken in consultation with relevant stakeholders. Following assessment and consultation the well lease is prepared for drilling operations.

3.2.2.1 Planning, scouting and assessment

The planning, scouting and assessment process for a new well typically involves:

- Santos and any joint venture participants agree on a proposed subsurface target location
- Landholder, traditional owner and stakeholder consultation and notifications undertaken to ensure all parties are aware of possible risks to infrastructure and their operations
- Field location is scouted and the well lease and access location(s) refined to minimise potential impacts associated with ground disturbance and infrastructure development
- Sacred site approvals are requested
- Environmental assessment undertaken using scout data, public and Santos database and GIS information and field inspection where appropriate (e.g. new areas or sites with potential environmental sensitivity)
- External approval for work programs (where required) are obtained

- Specifications / work packages are developed for well lease, access track and associated infrastructure construction
- Drilling program and well design are developed and approved
- Activity Notification is provided to the regulator.

3.2.2.2 Well lease and access roads

The objective of constructing a well lease is to create a stable working platform suitable for safely undertaking drilling, completions and well operations. The lease incorporates safe access and areas for the drilling rig, generators, fuel, chemical, casing and pipe storage, and associated portable buildings. It is also designed for subsequent operations like hydraulic stimulation, and generally incorporates the following standard features:

- A compacted and stable drilling rig hard stand area
- A mud sump for management and disposal of drill cuttings and the recirculation of water into the mud system
- An access road or track with clear entry and exit points for vehicles
- Mobile wastewater treatment systems for the disposal of ablutions waste from well site offices and accommodation
- Water storage tanks or ponds for drilling and/or hydraulic fracturing water and flowback fluid
- Proppant and chemical storage for drilling and/or hydraulic fracturing operations

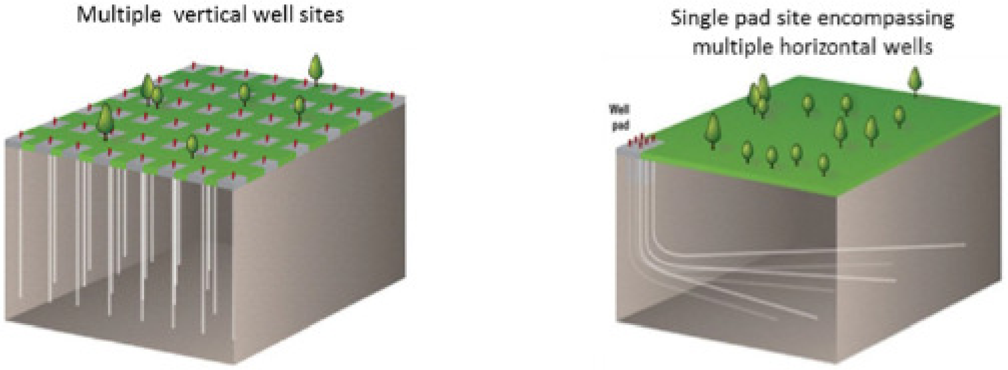
The size and layout of the well lease will vary depending on a number of factors such as the number of wells to be drilled (multi-well pads), the size and type of drilling rig, the number of hydraulic stimulation stages, the program for completion of the well(s) and the surrounding environment

The lease size required to accommodate an exploratory drill well would be approximately 145 m x 90 m. Whereas, the lease size required to accommodate hydraulic fracturing for a 10 well pad with 34 stimulation stages per well, is typically in the order of approximately 145 m x 210 m, with additional space required for proppant and water storage. The water storage pad would be approximately 240 m x 120 m to enable 2 x 18 ML double lined above ground ponds to be installed. The proppant and chemical storage pad is expected to be approximately 150 m x 150 m. This example is expected to represent the upper requirement for land disturbance.

The multi-well pads mentioned above are an opportunity to minimise disturbance and movement of equipment due to the ability to drill and complete multiple wells from a single well lease. They typically require a larger initial area, however the overall disturbance results in a smaller footprint per well. For example, approximately 10 wells can be drilled from a pad area the same size as two discrete single well locations. A schematic illustrating decreased land disturbance of multiple horizontal wells (Seven Generations Energy) is presented in Figure 3.

The well lease area prepared to accommodate necessary drilling and completion equipment and support services for the well will be the same area used for hydraulic fracturing the well. Where practical, Santos will aim to establish well leases with multiple wells where feasible to reduce the number of well leases (and disturbance) required.

Figure 3 Schematic well configurations illustrating decreased land disturbance of multiple horizontal wells



Source: (Seven Generations Energy)

Well lease construction methods vary depending upon the land system and soil type on which the well is to be drilled. Typically, topsoil with rootstock and vegetation is cleared and stockpiled for use later in restoration. Material sourced from borrow pits is imported where required to construct the lease pad, access roads and associated infrastructure. Borrow material is watered and rolled to achieve adequate compaction, provide a stable and trafficable surface and reduce dust. The risk of erosion is managed through the well pad design (i.e. surface water run-on and run-off) and engineered management controls. Considerations for siting and constructing well leases and associated infrastructure include:

- Selection of non-sloping well leases is preferable (this minimises the requirements for cut and fill or importation of borrow material to level the site)
- Employment of additional management controls in sensitive areas such as floodplains and proximity watercourses (where required)
- Constructing erosion control measures where appropriate (i.e. diversion banks or berms)
- Capping of sensitive terrain to preserve the underlying soils where required
- Avoiding environmentally sensitive and restricted areas and ensuring compliance with terms of sacred site certification
- Minimising disturbance of native vegetation and fauna habitat.

Due to the extended and often remote nature of drilling, completions and well operations, a temporary camp site is usually required to provide accommodation for drilling, completions and associated support personnel. Camp sites are located within proximity to well leases to minimise travel related risks.

Where possible, existing camp sites are used however, where new sites are required construction methods are similar to those employed for well leases with the exception that:

- There is more flexibility for locating camp sites as they are not required to be at a specific location, but typically within 10 km of the wellsite
- The level of compaction required to achieve a stable base is less than that required for well leases, as heavy vehicles are less present in these locations.

Camp sites locations are flexible and are typically constructed in areas where disturbance of native vegetation, particularly woody vegetation can be avoided or minimised. Camp location also takes into consideration landholder requirements, such as the potential for noise and dust generation and other operational hazards such as traffic.

Access tracks are required for drilling, hydraulic fracturing and completion operations, and vary depending on the land system and the expected frequency of use and traffic loadings. Access tracks for exploration wells may initially be constructed for temporary use only, compared with those constructed for development wells which are constructed to allow access for the life of the well, which could span 20-40 years.

Safety requirements are taken into consideration and define the minimum design standards for road and access tracks. Roads are constructed to withstand heavy and light vehicles associated with the activities. Where further developments or activities are planned, access tracks will be upgraded to reflect the nature of the development and traffic loadings.

3.2.2.3 Drilling

A well is drilled by rotating a drill bit while exerting downward force on the drill pipe. During drilling, fluid is pumped through the inside of the drill string to the drill bit and back up the outside of the drill string to lift drill cuttings out of the hole. The drilling fluid / drill cuttings are then channelled into tanks or pits where the drill cuttings are separated from the drilling fluid, and then drilling fluid is recycled down hole in a continuous process. The well is drilled deeper by adding a length of drill pipe to the drill string. Drilling fluids are also typically recycled onto other wells in a multi well scenario. Casing, which is concentric steel pipe, is installed into the well and cemented in place to provide the structural integrity and well integrity barriers for the designed life of the well. A typical drilling rig layout and lease and access roads required for Cooper Basin (SA) drilling operations is shown in Figure 4.

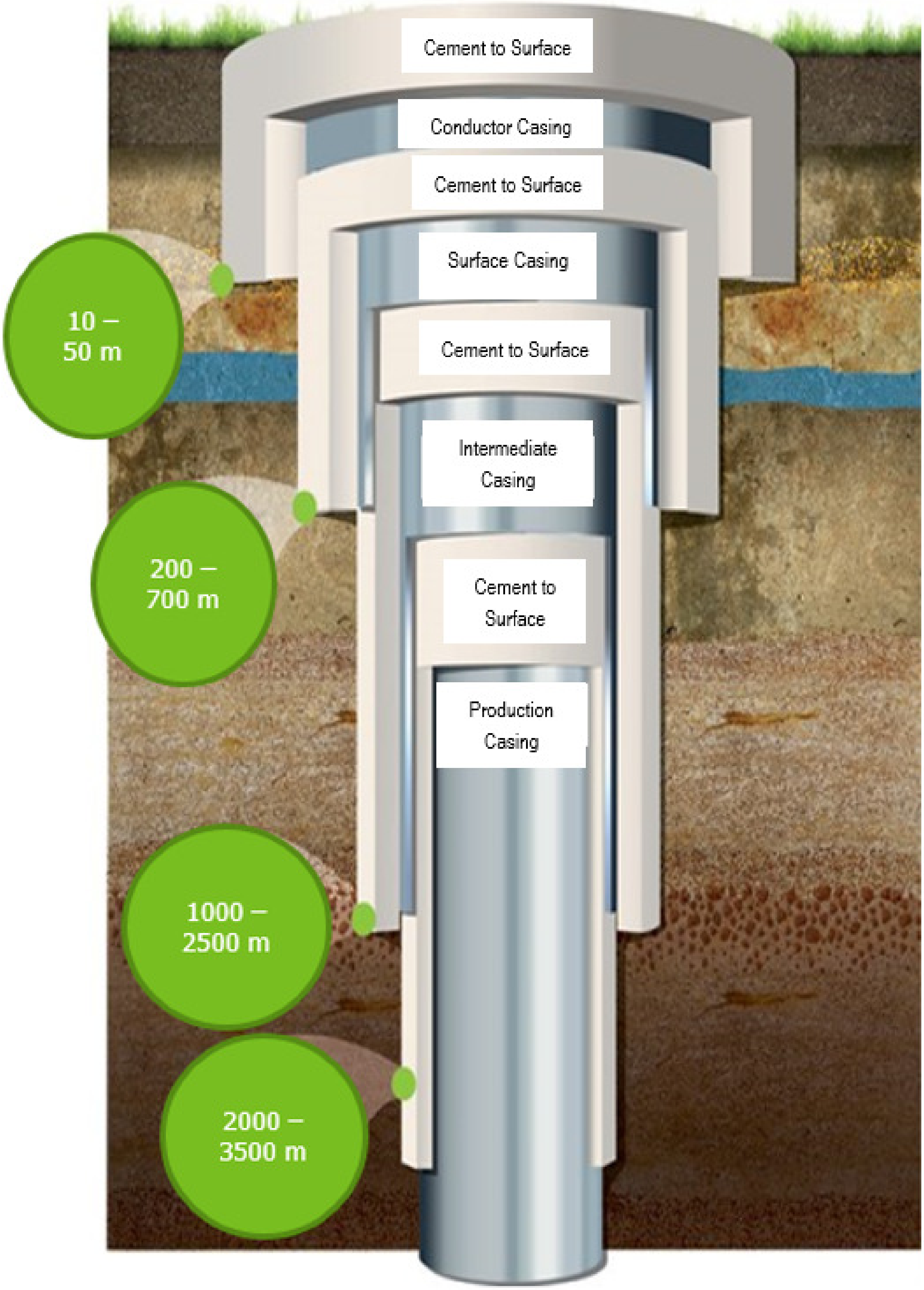
Figure 4 Example of well lease and drilling rig in Cooper Basin (SA)

Wells are drilled to reach the gas formation targets, through a series of hole sections; each hole section serves a specific purpose for well construction and well integrity as outlined below and depicted in Figure 5.

1. The Conductor Hole Section (406 – 508 mm outside diameter (OD)) may be drilled and cased to stabilise the surface sediments from the drilling of subsequent drilling phases (i.e. it prevents the loose soils from caving into the borehole), and is cemented into place to ensure an appropriately robust seal (up to ground level). The conductor casing (406 – 457 mm OD) also serves to isolate aquifers near surface, if present. A conductor casing string is installed as required by design for well construction purposes.
2. The Surface Hole Section (311 - 406 mm OD) is drilled and cased to achieve regulatory requirements for isolating shallow aquifer systems and to stabilise the well for subsequent hole sections. The hole section is drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do

not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. The surface casing (244 – 340 mm OD) is cemented in place from bottom to top to ensure effective pressure isolation of shallow aquifers from deeper hydrocarbon bearing zones encountered in subsequent hole sections. Finally, it is pressure tested to simulate well life design specifications. This is represented graphically in Figure 5 below.

Figure 5 Schematic of the hole sections and depth range (True Vertical Depth) expected for a typical NT shale wells. The well is depicted as vertical to more easily illustrate casing and cementing design, however may also be horizontal



Source: (Santos 2017)

3. After the surface casing is installed, a Blowout Preventer (BOP) is installed onto the well at surface to provide a second barrier along with the drilling fluid. At the commencement of drilling the next hole section (i.e. only 2-3m of new hole drilled), a Leak Off Test (LOT) or Formation Integrity Test (FIT) is conducted to determine the rock strength. This will ensure the well is drilled without risk of the rock failing due to exerted pressure.
4. The Intermediate Hole Section(s) (216 – 311 mm OD) may be drilled and cased to isolate deeper aquifer systems (if present) and/or to contain pressure that may occur during the subsequent hole section. The hole section is drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. As with the surface casing, the intermediate casing (178 – 244 mm OD) is cemented in place to ensure appropriate well integrity. Finally, it is pressure tested to simulate well life design specifications. An intermediate casing string(s) is installed if required by design for well construction and/or well integrity.
5. The Production Hole Section (152 – 216 mm OD) is drilled to intersect formation targets and is drilled to a depth below the lowest hydrocarbon bearing target. The hole section is typically drilled with drilling fluid that exerts a higher hydrostatic pressure on the rock face, than what is present naturally in the rock pore space, ensuring formation fluids do not enter the wellbore. Other techniques such as managed pressure drilling may be applied dependant on the downhole environment. Logging while Drilling (LWD) may be applied to gather data in real time to gain an understanding of the petrophysical environment.
6. Openhole logging is performed after the production hole section has been drilled and prior to the production casing being run. Wireline logging operations for Santos are undertaken by a number of different industry recognised specialist service companies. Different energy sources are lowered into the well via wireline including density, neutron, acoustic and electrical logging tools. Calculations based on the received signals are undertaken to evaluate the different parameters of the formation such as porosity, permeability, rock type and hydrocarbon saturation. This information is used to ascertain whether the well is economical to run production casing for future production. If the well is not economic, a decision not to run production casing may be made requiring the well to be plugged and decommissioned – refer to Well Decommissioning section and Figure 17 for specific requirements.
7. After the production hole is drilled and logged, production casing (114 – 152 mm OD) is installed to the total depth of the wellbore and cemented in place. It is pressure tested to simulate well life design specifications. The purpose of the production casing is to provide hydraulic isolation between the hydrocarbon reservoirs and all other overlying formations, to contain the pressurised fluid used to hydraulically stimulate the target zones, and to provide effective wellbore integrity for well production. The high quality steel casing is designed specific for each well.

3.2.2.4 Engineering design

Casing design scenarios are modelled through specialist software to simulate the design loads for collapse, burst and tensile failures, observed during the operational and production phases. The results of this analysis direct the selection of casing grade and weight. All casing is tested by Santos and the contractor using specific Quality Assessment and Quality Control (QA / QC) procedures prior to installation to ensure compliance with the Santos engineering and regulatory specifications.

After each hole section is drilled, the steel casing is cemented in place. The correct composition, volume and placement of cement is the construction aspect that is most important for well integrity. The cement serves two purposes – it provides protection and structural support to the casing while also providing zonal isolation between different formations, including aquifers. The cement and required additives are high quality materials produced specifically for oil and gas operations with the materials selected designed to address the specific conditions of a particular well.

Santos and the cementing contractor must ensure the cementing material and equipment is adequate to achieve the well design objectives and ensure effective isolation. Prior to pumping the cement, it must be lab tested against the engineering design and actual downhole conditions such as temperature. The cement is tested using specific QA / QC procedures and includes the following:

- Slurry density
- Thickening time
- Fluid loss control
- Free fluid
- Compressive strength development
- Fluid compatibility (cement, mix fluid, mud)
- Sedimentation control
- Expansion or shrinkage characteristics of the set cement
- Static gel strength development
- Mechanical properties (e.g. Young’s modulus, poisson’s ratio, elastic / compressibility characteristics).

Cased hole logs can be run inside the cemented casing to validate the quality and integrity of the cement sheath bond to the casing and to the formation. Typically, these logs include:

- Gamma ray - measures naturally occurring gamma radiation to characterise the rock or sediment in a borehole
- Casing collar locator - a magnetic device that detects the casing collars
- Cement bond log - an acoustic device used to measure the properties of the cement sheath and the quality of the cement bond between the casing and the formation.

As mentioned, the cement bond log is an acoustic device that can detect cemented or non-cemented casing. It works by transmitting a sound or vibration signal into the casing, and then recording the amplitude of the arrival signal. Casing that has no or poor quality cement surrounding it (i.e. free pipe) will have large amplitude acoustic signal because the energy remains in the pipe and isn’t transmitted to the formation. Casing that has a good cement sheath (fills the annular space between the casing and the formation and effectively couples the two) will have a much smaller acoustic amplitude signal as the energy is absorbed by the formation due to effective acoustically coupling. Santos uses experienced contractors to identify the key features of the cement quality to ensure the integrity of the cement seal for each casing pipe sheath. If cement is not of sufficient height or quality and deemed by the operator to be unsafe for continued operations, hydraulic stimulation will not proceed until it can be effectively remediated.

3.2.3 Hydraulic fracturing

This section describes the hydraulic fracturing and associated activities, as defined by the Scientific Inquiry’s Terms of Reference (NT Government, 2017), and reproduced in Section 1.0.

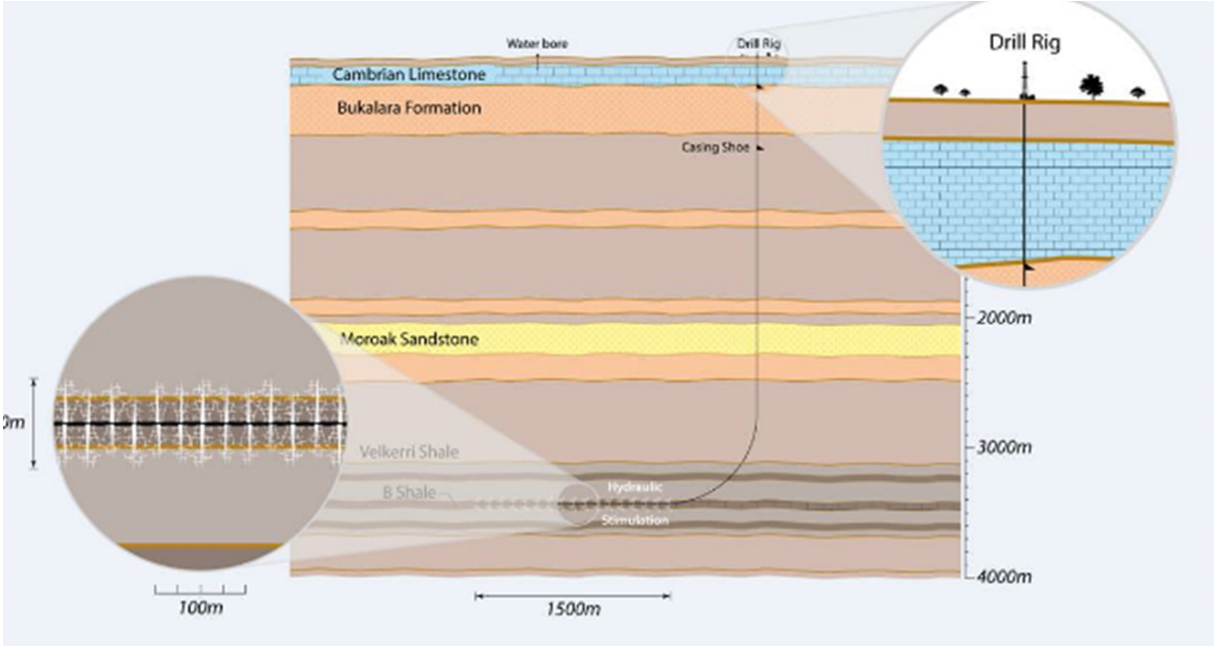
Hydraulic fracturing (often referred to as hydraulic stimulation or “fraccing”) is a predominantly physical process in which hydraulic pressure is applied to a fluid (oil, gas or water well or bore) to increase the effective permeability of the formation rock. The process creates narrow pathways (fractures) in the shale gas reservoir to improve its ability to transmit gas back to and then out of the well.

It is noted that, unlike coal seam gas, no depressurisation via groundwater extraction is required to produce shale gas. Once the hydraulic stimulation is complete much of the water introduced into the well returns to surface after the introduced pressure is removed. The naturally occurring shale gas flows from the shale, via the enhanced permeable (fracture) zones, to surface of the well.

After pre-fracturing assessment and hydraulic fracturing design, onsite activities include site setup, perforation of the well casing and cement into discrete targeted sections of the cased bore (to access most viable gas bearing shale formation), injection of hydraulic fracturing fluid and flowback of the injected fluid.

A schematic of a typical shale gas bore, including both vertical and horizontal drilling and the fractured sections (extent and location) within the targeted shale unit, is illustrated in Figure 6.

Figure 6 Typical shale gas bore showing vertical and horizontal drilling and hydraulic fracturing targeting shale unit



The process of hydraulic fracturing is detailed below.

3.2.3.1 Pre-fracturing assessment and hydraulic fracturing design

Operators investigate the subsurface conditions, including hydrogeological and mechanical properties of the target and surrounding geological units, to design the hydraulic fracturing program to strategically identify and reduce the possible risks involved (IESC, 2014).

To understand the geological formation and priorities for the hydraulic fracturing program, key aspects of subsurface characterisation (Beckwith, 2010), (New South Wales Trade and Investment Resource and Energy, 2012) include:

- Describing all geological units
- Assessing target formation permeability
- Analysing subsurface distribution of stresses and faults
- Assessing fluid loss characteristics.

The hydraulic fracturing program is designed after the subsurface characterisation is complete. Part of this design is the prediction of fracture growth within the target zone. Specific hydraulic fracture simulation software is used to predict the geometry of fractures, while the orientation is determined from the in situ stress field (IESC, 2014). Typical inputs to numerical models include volume and properties of the fluid and proppant, closure stress, pressures within pores, permeability, mechanical properties and layer geometry.

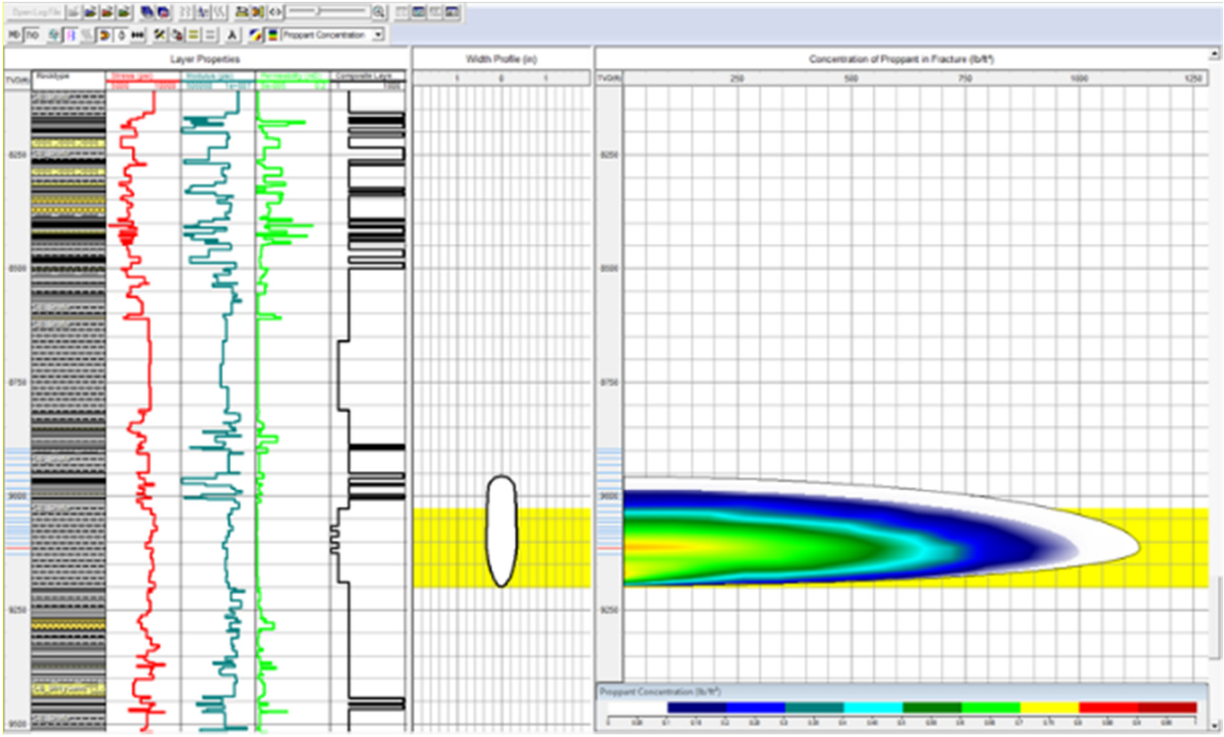
Open hole and cased hole logging provides information required for the hydraulic stimulation design process, including rock stress and lithological parameters. This data is processed using specialist stimulation software to develop an optimal design. The basis of well specific hydraulic fracture design is to create a fracture within the target formation that will produce hydrocarbon through the number of required fractures. This is achieved by modelling fracture length, fracture conductivity, and fracture height for each created fracture as depicted in Figure 7.

A number of considerations influence the final design for each stimulation treatment, including:

- Depth and thickness of the formation target
- Lithology of formation target and bounding layers
- Minimum and maximum horizontal stress across all layers (target and bounding)

- Thickness of the seals above and below the target reservoir formation
- Porosity and permeability of the formation
- Pore fluid saturations (percentage of formation pore volume occupied by oil, gas or water)
- Pore fluid properties (e.g. Density, water salinity)
- Well performance data, including flow rates, formation pressure and produced fluid properties
- Formation boundaries (as identified from seismic data)
- Bulk rock density, elastic properties and compressibility
- Natural fracture networks
- Stress field analysis to determine the maximum principle stress direction and the minimum principle stress direction.

Figure 7 Modelled output from industry accredited software for a Cooper Basin horizontal well shale hydraulic fracture



Source: (Santos 2014)

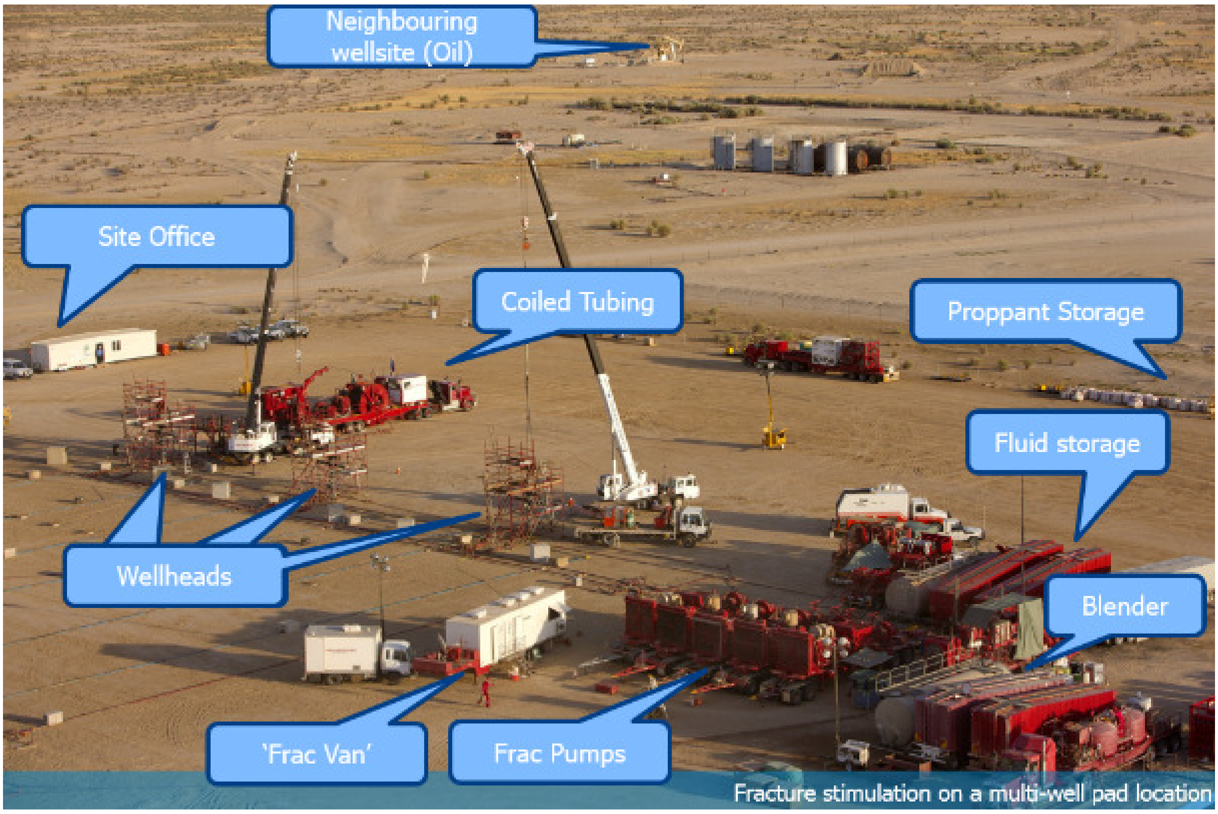
3.2.3.2 Site set up

The well lease provides a stable working platform suitable for safely undertaking hydraulic fracturing operations. The lease area provides adequate space for the hydraulic fracturing vehicles and equipment, generators, fuel and chemical storage, casing and pipe storage and associated portable buildings. The well lease area generally incorporates the following standard features:

- A compacted and stable hard stand area
- An access road or track with clear entry and exit points for vehicles
- Mobile wastewater treatment systems for the disposal of ablutions waste from well site offices and accommodation
- Water storage tanks or ponds for hydraulic fracturing make up water and flowback fluid
- Proppant and chemical storage for drilling and/or hydraulic fracturing operations.

Example hydraulic fracture set up is shown in Figure 8.

Figure 8 Example hydraulic fracture spread for 3-well pad in Cooper Basin, SA



Source: (Santos, 2017)

3.2.3.3 Stimulation

After determining that the well has the required design and well integrity to undergo stimulation and completions, the well is handed over to 'complete' the well and set it up for production. Hydraulic fracture stimulation is not part of the drilling process but is a completion technique applied after the well is drilled. The intent of hydraulic stimulation is to place a highly conductive channel (fracture) into the reservoir to increase the flow capacity of the well. It is a process that has been used in the oil and gas industry since 1947. The Society of Petroleum Engineers (SPE) estimates that over 2.5 million hydraulic stimulation treatments have been undertaken in oil and gas wells worldwide. It has been successfully used on wells in the Cooper Basin for nearly 50 years without a primary barrier breach and is currently performed in many hydrocarbon basins around Australia, including the Amadeus Basin in Northern Territory.

The stimulation process involves pumping water, a specific blend of chemical additives and a propping agent such as sand or ceramic beads down the well at sufficient pressure to create a fracture in the target formation. Proppant keeps the fractures open once the pump pressure is released which thereby improves the productive potential of the well. A fracture created in deep shale reservoirs, will propagate laterally from the well in a vertical plane. An unconventional shale gas well typically takes 7 to 10 days to complete hydraulic stimulation operations, with a hydraulic stimulation fluid flowback period of 3 to 30 days, depending on the reservoir and clean up profile.

Code of Practice

To ensure risks are appropriately managed, Santos adheres to strict regulatory requirements such as the "Code of Practice - For the construction and abandonment of petroleum wells and associated bores in Queensland".

The Code of Practice has the following mandatory requirements:

- During the well design and planning process, petroleum tenure holders must identify any aquifers at risk of being impacted by hydraulic stimulation operations and fluids
- If any such aquifers have been identified, hydraulic stimulation activities must be designed to not impact these aquifers
- Hydraulic stimulation for gas wells requires verification of cement bond quality using appropriate cement evaluation tools
- If the annulus between the production casing and the surface/intermediate casing has not been cemented to the surface, the pressure in the annular space must be monitored and controlled while conducting hydraulic fracture stimulation
- The pressure relief valves on the pump units must be set so that the pressure exerted on the casing does not exceed the working pressure rating of the casing and wellhead.

Santos has a long history of demonstrated well integrity during hydraulic fracturing operations. In nearly 50 years of hydraulic fracturing operations on over 1,150 wells, there has never been a loss of the primary barrier during the fracture treatment. The primary barrier during the stimulation phase is generally the production casing, with the secondary barrier being the surface well pressure control. Should the primary barrier fail, a pressure relief valve (PRV) installed to monitor pressure between the primary barrier and surface casing, is triggered to open at a pressure well below the failure point of the surface casing. This ensures that the surface casing is not exposed to pressure above its design specification, and as a result prevents the risk of well failure. Also, programmable pressure triggers (kickouts) on each of the high pressure pumps will physically shutdown each pump (and associated pressure) if a certain trigger pressure is reached. This trigger is below the design specification of the well. If the primary barrier did fail during hydraulic fracturing operations, operations would cease and it would be repaired to meet the design requirements before going forward with completing the well again.

Proppant and Chemicals

Santos has used the following three primary types of perforating in the Cooper Basin. These same methods will be considered for application in the NT.

- Wireline Conveyed Perforating (WCP) – the most widely used perforating technique in the Cooper Basin. As the name suggests, WCP uses wireline to deploy the perforating charge.
- Tubing Conveyed Perforating (TCP) - uses the same technology as conventional wireline perforating but is run using a coiled tubing unit or jointed tubing (not wireline). TCP is the preferred perforating method when operating in underbalance or overbalanced conditions.
- Hydrojetting – uses sand and water jetted through small holes in the bottom hole assembly to create holes in the casing across the target formation – there is no perforating charge. Hydrojetting allows for targeted or pinpoint perforating, creating three to four holes per event or stage.

In shale hydraulic stimulation treatments, water accounts for more than 90% of the mixture and sand accounts for about 5-9%. Chemicals generally account for around 1% of the mixture and assist in carrying and dispersing the sand in the low permeability rock.

In accordance with regulatory requirements, the chemicals additives are often subject to full disclosure. The chemical additives are not specific to the hydraulic fracture stimulation process, having many common household uses such as in swimming pools, toothpaste, baked goods, ice cream, food additives, detergents, cosmetics and soap. The chemicals used provide the following functions:

Viscosity – gelling agents (natural plant based) are added to the water to provide viscosity to enable the proppant material to be transported down the well and into the created fractures.

Friction reduction - to reduce the force required to pump the fluid, making the fluid more slippery and easier to pump at high pressures and high rates required to create the fracture network.

Biocide – added to ensure that there are no microbes or organisms present in the water that will affect the gelling agents and to ensure they will not enter and affect the hydrocarbon reservoir.

Scale and corrosion – scale and corrosion inhibitors are added to prevent deposition of mineral scales and to prevent corrosion of the primary wellbore barrier; the steel casing.

Surface tension – surfactants or surface tension modifiers are added to assist the flowback of fluids from the formation.

Water Management

The source of water for hydraulic stimulation is considered in detail during the initiation phase of a project. Depending on availability and in accordance with applicable regulations, the water is typically sourced from:

- produced water that has flowed back as part of the fracture stimulation process
- produced formation water from gas production facilities
- surface water sources
- groundwater sources such as local boreholes.

Based on operational experience, it is anticipated that Santos use on average 1 ML for constructing a well lease and drilling a well and 1 ML for each fracturing stage. Therefore, for a long horizontal well with 34 fracturing stages, the total volume of water required will be approximately 35ML.

Speculative estimates of total water use from unconventional gas extraction should some Australian basins be fully developed (FROGTECH, 2013, p27) were modified for the NT extent of these basins in the International Association of Hydrogeologists (NT Branch) submission (Table 1, p5). Assuming that economic resources make up 5% of a basin, wells are spaced at 800 m, fracturing each well requires 15 ML, and development occurs over 25 years, the total water requirement in four NT basins was projected to be 836 GL, or an average of 33.4 GL/year. This compared to an estimated sustainable ground water yield of 2,747 GL/year from these basins, and a current estimated ground water extraction in these basins of 48 GL/year. It is important to understand that these projected water requirements were based on assumptions that imply development over 25 years of an extremely large number of gas wells in the NT- between 10,400 and 17,850 wells in each basin, and a total of 55,700 wells in the four basins (IAHNT submission).

A more realistic development scenario (if any) is some 100 production wells drilled and fractured in the NT during the next 7-10 years, with an average water requirement (assuming these are all long horizontal wells) of 150-240 ML/yr (0.15-0.24 GL/yr). If market growth and infrastructure development allows, then the ongoing development of up to 100 wells per year (similar to the current level of activity in the Cooper Basin) may be feasible. This may result in a longer-term annual industry water requirement of 1.5-2.4 GL/year for hydraulic fracturing.

The shale gas industry only uses a small fraction of the total water usage for agricultural, industrial and other purposes. The take of water is also generally only required during the initial drilling and development period with even smaller volumes required for on-going operations, however new wells are required to replace gas decline over time. [Note: page 5 of the Hawke NT Report says: It is important to place the scale of water requirements for hydraulic fracturing in the context of other water uses. Moore (2012) estimated that the water requirement of a shale gas well over a decade was equivalent to that needed to water a single golf course for one month, or to run a 1,000 MW coal-fired power plant for 12 hours.

If a move from the exploration phase to development phase occurs, facilities are set-up to enable the capture and recycling of flow-back fluid to the extent feasible, thereby reducing the amount of additional water required for each subsequent hydraulic stimulation operation. This has the potential to reduce the total additional water requirement to less than 18 ML per well. Flowback water (and subsequently process water) can be reused for subsequent fracturing operations if it can be treated to the required standard in an economically viable way.

A considerable volume of the injected stimulation fluids are recovered upon flowback of the injected fluid. Studies performed by the (US Environment Protection Agency (EPA), 2004) indicated that approximately 60% of the stimulation fluids are recovered in the first three weeks, and total recovery was estimated to be from 68% to 82%.

Once pumped into the well, the injected stimulation fluids undergo chemical and physical changes in their properties. The general changes to the chemicals that are injected include:

- Acids reacting with minerals and creating salts, water, and carbon dioxide
- Corrosion inhibitors bond with pipe surfaces, are broken down by micro-organisms, or returned as flowback water where they undergo further biodegradation
- Biocides that are degraded by microorganisms or small amount are returned in flowback water where they undergo further biodegradation and photo-degradation
- Friction reducers remain in the formation and are broken down by microorganisms or small amounts returned in flowback water where they undergo further biodegradation
- Surfactant are adsorbed onto the hydrocarbon reservoir surfaces or return with the flowback water where they undergo biodegradation
- Gelling agent broken down by the “breaker” and returns with flowback water where they undergo biodegradation
- “Breaker” reacts with “gel” and “crosslinker” to form ammonia and sulfate salts that are returned in flowback water
- Crosslinker combines with the “breaker” in the formation to create salts that are returned in flowback water.

Comparison of Shale and Conventional Hydraulic Stimulation

Shale hydraulic stimulation treatments utilise essentially the same process and techniques employed in conventional hydraulic stimulation treatments with the main differences being:

- Treatment size – shale stimulations often require 2-3 times the volume / weight of proppant compared to a typical conventional well
- Treatment type – shale stimulation fluids are often friction reduced water treatments (i.e. “slick water treatments”) which uses less chemical additives than a conventional gas crosslinked fluid fracture treatments.
- Horsepower requirements – shale stimulation can be subject to higher pore pressure and geomechanical stresses than conventional stimulation and therefore require up to twice as many pumping units. Shale treatments generally use a friction reduced water fluid design, which has less viscosity to suspend the proppant. This can be overcome by pumping at a higher fluid rate and utilising more horsepower.

Process

A number of steps are involved in the hydraulic stimulation process to pump the designed fracture treatment:

- Diagnostic Fracture Injection Test (DFIT) to validate and update the proposed stimulation design. This involves injecting a small volume of water, shutting down the surface pumps and monitoring pressure decline to evaluate near wellbore entry friction, fracture gradient, fluid leak off, and minimum horizontal stress. This stage is typically only performed in the exploratory / appraisal stages of development, or until localised fracture characteristics are defined.
- Main stimulation treatment; consisting of pad volume, slurry stages with increasing proppant concentrations, and flush stage to displace last slurry stage through the perforations and into the fracture.
- Mechanical isolation of the completed fracture stimulation stage.
- Perforate the next stage to be hydraulically stimulated and repeat the process in 2 to 4 above until the final fracture stimulation stage is completed.
- Remove all mechanical isolation devices by milling out the mechanical isolations.
- Flowback well to clean up fracture stimulation fluids and monitor hydrocarbon production. This step may also be combined with an Extended Production Test (EPT) to help define the field reserves and expected production life. The flowback of stimulation fluid is conducted through a separator, which separates and captures liquids, and flares produced gas through a vertical ‘flare stack’.

The above method represents the “plug and perf” technique for fracture stimulation. Another technique is to use coiled tubing assisted annular stimulation which is used to provide a conduit for “pin-point fracturing”. Coiled tubing is run into the well to the deepest target. The bottom-hole assembly run on the end of the coiled tubing incorporates a jetting assembly which allows for low concentration sand slurry to cut holes or slots into the casing and cement. The hydraulic stimulation treatment is then pumped into the coiled tubing / casing annulus to initiate and propagate the fracture.

The final technique is to use “stimulation sleeves”, which are run and cemented in place with the production casing across the shale targets requiring hydraulic fracture stimulation. The smallest internal diameter (ID) stimulation sleeves are run at the base of the well, and sequentially increase in size up to the top stimulation target. Dissolvable metallic stimulation balls are dropped (from smallest to largest), which seat on corresponding stimulation sleeves. The application of differential pressure will open the stimulation sleeve and initiate the hydraulic fracture, as well as hydraulically isolating the previous stimulation target. Once all the stimulation stages have been completed and the wellbore heats up, the stimulation balls dissolve to re-establish a flow path with the shale targets, at which point, the flowback of fluid can commence.

Diagnostics

During a fracture stimulation treatment, computer assisted live monitoring allows for potential problems (surface or down-hole) to be identified and corrected quickly. An example of live monitoring applied to downhole conditions is if pressure communication between the annulus of the well and inside of the well is identified. Where communication is identified, it may be an indication that the first barrier control (as part of the well’s integrity management) has been affected and the treatment will be stopped immediately.

In South Australia, Santos has trialled the use of advanced stimulation monitoring techniques such as microseismic monitoring, which can be used to evaluate fracture azimuth, fracture height and fracture half length. This information can be further used to calibrate the hydraulic stimulation model predictions. Microseismic monitoring involves the use of sensitive receivers (“geophones”) at the surface or within one or more nearby wells to detect and locate in 3D space the releases of energy associated with the propagation of the stimulated fractures.

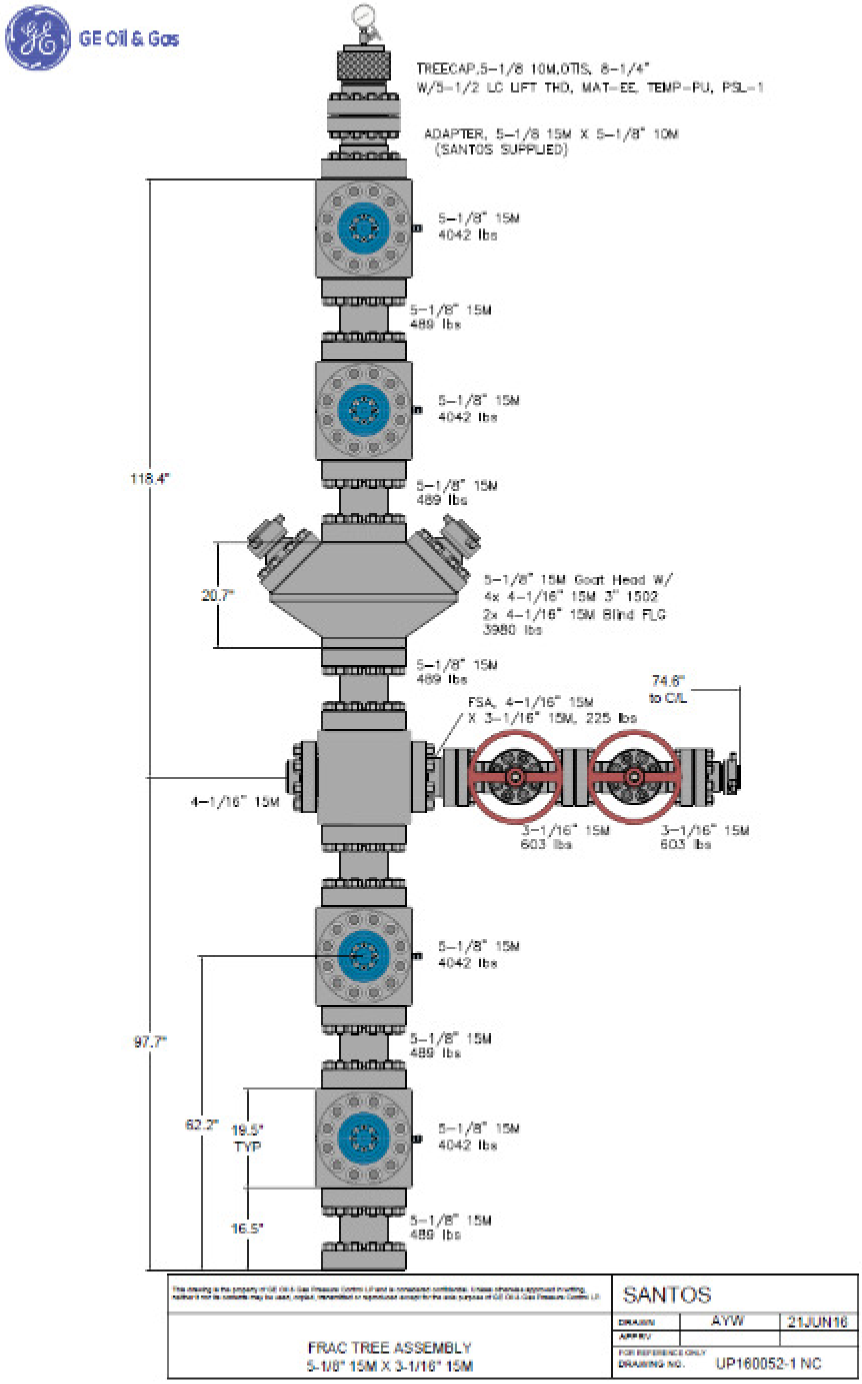
The microseismic results are supported by detailed studies such as by Fisher and Warpinski (2012) which have reviewed height growth data from key unconventional (shale) plays in the US including the Barnett, Marcellus and Woodford shales.

Equipment

The equipment and machinery required to carry out a hydraulic stimulation operation is highly mobile and able to be installed and removed relatively quickly (generally within a couple days). They are designed to comply with state and federal regulations for road transport, and are fitted with safeguards such as an in-vehicle monitoring system (IVMS) to ensure compliance of the individual contractors.

The Wellhead Figure 9 is used to inject into and control the well, during hydraulic stimulation operations of shale wells. The stimulation fluids, which are injected from the surface via the wellhead, are injected through the perforations in the well casing under high pressures in order to physically fracture the reservoir rock. The wellhead provides the primary surface barriers for well control.

Figure 9 Typical hydraulic stimulation wellhead used in the Cooper Basin for shale stimulation operations



‘Turkeys nest or above ground storage tanks Figure 10– on site, a synthetic lined pit (turkey's nest) or above ground water storage tank provides temporary water storage for use in the hydraulic stimulation process. Source water can either be trucked or piped along a temporary network. Small dosages of biocide are added to control algal growth particularly under warm and stagnant conditions. Following completion of works, temporary water storage infrastructure is either backfilled or removed from site.

Figure 10 Above ground storage ponds used for stimulation make-up water storage and flowback water storage in the Cooper Basin. Source: Santos 2013

Sand Trailer Unit – a large, multi-compartment trailer that holds proppant (sand or ceramic material) required for the treatment Figure 11. When proppant is required, a conveyor system distributes proppant from the compartments to the blender unit.

Figure 11 Sand trailer unit. Source: Halliburton 2012

Blender Units Figure 12– In general, two different blending units are used: A pre-gel blender; and a down-hole blender. The pre-gel blender combines the source water with additives required for the base stimulation fluid (also known as "linear gel") and proportions of required additives to provide the final hydraulic stimulation fluid. The down-hole blender unit then proportions proppant to the stimulation fluid to provide the proppant concentrations specified in the treatment design. The final hydraulic stimulation fluid, without proppant, is referred to as the "clean fluid". The final hydraulic stimulation fluid, with proppant added, is referred to as "slurry". Chemical additives are precisely measured, controlled and recorded by the blender throughout the stimulation treatment process.

Figure 12 Blender unit. Source: Halliburton 2012

High Pressure Pumps Figure 13 – reciprocating triplex or quintaplex pumps that receive low pressure hydraulic stimulation fluid from the down-hole blender and inject these fluids at the required higher pressure into the well during the hydraulic stimulation process. 6-20 units may be used on shale hydraulic fracture stimulation treatments. The pumps contain programmable pressure triggers (kick outs) to prevent pressure from exceeding the wellbore design limits. High pressure treating iron connecting the stimulation pumps and the wellhead also contain pressure safety valves (PSV's), which are set to open at a certain pressure set point to ensure the well components are protected.

Figure 13 High pressure pump. Source: Halliburton 2012

Control or Data Acquisition Unit Figure 14– telemetry from all units are connected to a central control room during the hydraulic stimulation treatment. Treatment parameter data, including surface and bottom-hole pressure, pumping rate, chemical rate and fluid density, are monitored, recorded and plotted (Figure 13). Treatment supervisors monitor and control the treatment to ensure that the treatment is pumped according to design. Satellite communication facilities allow further 'remote' oversight by technical experts.

Figure 14 Control unit. Source: Halliburton 2012

'*Coiled Tubing' Unit* Figure 15– a Coiled Tubing Unit (CTU) has many uses within Santos operations but is not always required as part of a hydraulic stimulation operation. On some occasions the stimulation treatments are placed using coiled tubing assisted annular fracturing, as opposed to "perf and plug" completions. The coiled tubing can be used in place of wireline jet perforating by jetting holes through the casing and cement using abrasive jetting. Once the perforations are jetted, the coiled tubing is left inside the well and the hydraulic stimulation treatment is pumped down the coiled tubing / casing annulus. Part of the coiled tubing bottom-hole assembly allows a mechanical barrier to be set which protects a stimulated interval below, while pumping a stimulation treatment in a subsequent target above. Following a treatment, the coiled tubing is pulled up to the next interval and the abrasive jetting procedure is repeated.

Figure 15 Coiled tubing unit. Source: Halliburton 2012

Flowback Pond – A higher walled (thicker) plastic lined flowback pond is constructed as part of lease preparation or as an alternative an above ground tank Figure 10 will be installed. This pit/tank is used to receive fluids produced during stimulation operations and during the initial clean-up phase (following stimulation activities). Ponds are double lined with UV stabilised synthetic liners to manage the risk of leaks. Typically, after the initial clean-up phase the produced fluids are treated for re-use or disposed at a licenced waste disposal facility.

3.2.3.4 Injection and isolation of hydraulic fracturing fluid

Once the well has been perforated in the depth interval that is to be hydraulically fractured, fluid injection is performed.

Hydraulic fracturing fluid is injected into the well at the surface through the wellhead. The perforation zones are isolated by either a coiled tubing unit with packers, a bridge plug set by a wireline operator, or by a baffle and ball-drop system.

Following isolation of the perforated zone, injection of fluid commences. The hydraulic fracturing fluid is forced into fractures and remains within the target reservoir. The bore design and construction, comprising multiple physical barriers such as cement and steel casing, ensure that the hydraulic fracturing fluid does not come into contact with overlying strata, including aquifers. The integrity of these barriers is tested before hydraulic fracturing activities are undertaken (see discussion of well integrity in Section 7.1).

The injection pressure, injection rates, slurry volumes, fluid viscosity, and proppant concentration are monitored in real-time during each injection. Downhole pressure information is also recorded and reviewed during the hydraulic fracture stimulation operation. Down-hole pressures are calculated based on wellhead pressure, fluid density, casing diameter and the depth to the target formation. When a coiled tubing unit is used as part of the operation pressure is monitored: inside the casing above the top packer of the tool, inside the coiled tubing delivering the fluid and inside the wellhead at surface.

Once the entire hydraulic fracturing operation is complete for a well, a completions rig or coiled tubing unit will generally mill out the bridge plugs or baffles that were installed for the hydraulic fracturing operation, to clear them from the well.

3.2.3.5 Return of injected fluid and water (flowback)

Once the injection process is complete, the internal pressure of the rock formation causes fluid to return or “flowback” to the surface through the shale gas well. This fluid is also known as flowback contains the dissociation or breakdown products of the injected chemicals plus naturally occurring geogenic compounds

A considerable volume of the injected fluids are recovered as flowback. Studies performed by the US EPA (US Environment Protection Agency (EPA), 2004) indicated that approximately 60% of the fluids are recovered in the first three weeks, and total recovery back to surface was estimated to be from 68–82%.

The flowback water is typically temporarily stored tanks or lined pits before treatment for reuse or disposal.

3.2.3.6 Reuse, treatment and release of wastewater

The recovered fluid, or flowback, is treated and stored for reuse in the next hydraulic fracturing event or disposed of at licensed waste facilities. Waste treatment and management facilities will be modular, factory fabricated and transported to site for assembly and connected to piping, electrical controls and instrumentation. By-products from wastewater treatment are contained in fully engineered, purpose-built structures for further treatment and disposal. Strategic opportunities for further treatment and beneficial use reassessed once composition and technology is assessed.

3.2.3.7 Completions and connections

At the end of the clean-up phase, a workover rig is required to install the production tubing and associated completion equipment such as packers, nipple profiles, tubing hanger, and the production tree, in preparation for connecting the well for inline production flow.

Production from each well is controlled with a metering skid which includes features such as overpressure protection, flow rate control, well safety shut-in, pressure and temperature monitoring.

After the drilling, stimulation, completion and connection activities are complete, the well lease is transitioned towards the operational phase which involves:

- Fencing the drilling mud sump to prevent stock and wildlife access

- Backfilling the well conduits
- Removal of drilling and completions equipment and waste
- Pumping out additional water from the turkey's nest (if installed) and removing the liner or removal of the temporary storage tank.

3.2.4 Rehabilitation

On completion of well, the well lease area is partially rehabilitated to retain a smaller footprint for the remainder of the production lifecycle; or if the well is not deemed productive, decommissioned and rehabilitated in accordance with landholder agreements and conditions of regulatory approvals.

3.2.4.1 Partial rehabilitation

Once the well is confirmed as economical and ready to be used for production, partial rehabilitation of the well lease area is completed. Partial rehabilitation involves:

- Backfilling the drilling sump
- Partial ripping and respreading of topsoil and rootstock on excess lease areas to promote revegetation and stabilisation of the lease edges
- Backfilling the water storage (if installed)
- Backfilling additional pits used for loading and offloading earthmoving equipment
- Removing capping and ripping access loop roads
- Ripping (uncompacting) the camp site and camp access track (unless required for future operations)
- Stabilising and re-establishing growth medium and vegetation.

Examples of partially rehabilitated well lease areas are shown in Figure 16.

Figure 16 Examples of partial lease rehabilitation of producing gas wells in the Cooper Basin

During the wells producing life, which may be 20-40 years, it may be necessary to conduct some workover operations in order to maintain or revitalise the wells producing capacity, or to maintain the level of well integrity required for production. Some workovers may require wireline equipment to lower tools into the hole to undertake operations. For more complex operations, a workover rig is required.

Whilst not exhaustive, such operations may include:

- Cleaning out production conduit
- Replacing production tubing
- Plugging the well
- Changing or adding production equipment

- Hydraulic stimulation and re-stimulation operations
- Repairing casing
- Drilling deeper
- Retrieving or drilling out obstructions in the well
- Re-perforating existing zones in production
- Well bore decommissioning.

3.2.4.2 Well decommissioning

When a well comes to the end of its productive life or if the well is drilled and deemed uneconomic to move to the ‘complete’ phase, a decision is made to decommission the well. The primary objective of well decommissioning is to isolate hydrocarbon and water bearing formations and eliminate migration pathways (between the reservoir, other formation / aquifers and surface). Wells earmarked for decommissioning are subject to individual evaluation to determine the most appropriate decommissioning program.

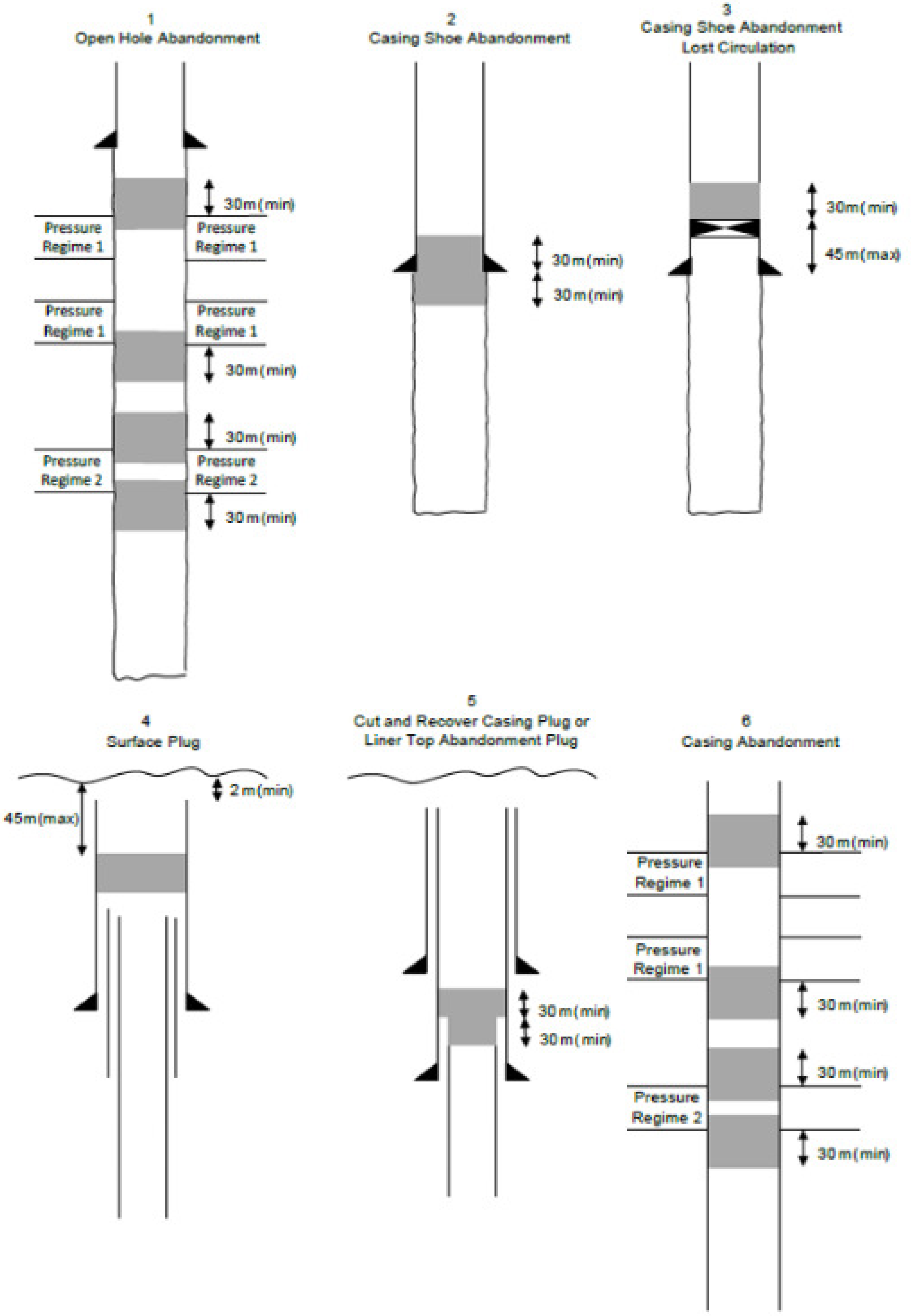
Perforated hydrocarbon zones are isolated with cement plugs and / or bridge plugs and cement bond logs (CBL) used and assessed to ensure that the cement behind the production casing is adequate to avoid migration pathways. If isolation is not evident behind the production casing following CBL integrity checking, the casing will be perforated and squeezed (with cement) to effect isolation. An additional cement plug is placed in the surface casing prior to cutting off the well head below ground level.

Consideration of the following is taken into account when plugging and decommissioning the well:

- Isolate all formations that have hydrocarbon shows
- Isolate formations with different pressure regimes
- Set plugs across intermediate casing shoe (if present) to minimise the potential for cross flow between aquifer systems and hydrocarbon bearing intervals
- Set plugs across surface casing shoe
- At the surface set a plug in the well prior to cutting off the surface casing bowl.

Examples of the decommissioning schematic for completed wells per the Santos Drilling and Completion Management System (DCMS) (Santos, 2016a) are illustrated in Figure 17.

Figure 17 Schematics of required cement barriers for well decommissioning



3.2.4.3 Final rehabilitation

Final rehabilitation is undertaken if the well is uneconomic or at the end of the well's productive life or if there are no ongoing requirements to access the location. Final decommissioning of the well bore and associated surface infrastructure is undertaken once production infrastructure and facilities have been removed. Final surface rehabilitation involves:

- Backfilling pits including the drilling mud sump, water storages (if present)
- Where practicable, removing capping material from the well lease and camp site pad areas and returning material to borrow pits
- Ripping and re-contouring of well leases and camp sites and respreading of stockpiled topsoil and cleared vegetation to represent as near as practicable to the original landform
- Removal of capping from the access track and returning to the borrow pit
- Ripping on the contour to promote revegetation and minimise erosion
- Removing windrows (flow on / off controls) to ensure that water flows are not impeded.

Example of rehabilitated well lease area in the Cooper Basin (SA) is shown in Figure 18.

Figure 18 Example of rehabilitated well lease area in the Cooper Basin

4.0 Santos tenements in the NT

4.1 Santos exploration permits

Santos currently holds explorations permits in the Amadeus Basin and the McArthur Basin/Greater Beetaloo Basin as shown in Figure 19. These permits result from two ventures – one in the Amadeus Basin partnering with Central Petroleum and the other in the McArthur Basin with Tamboran Resources. Santos is the operator in both ventures.

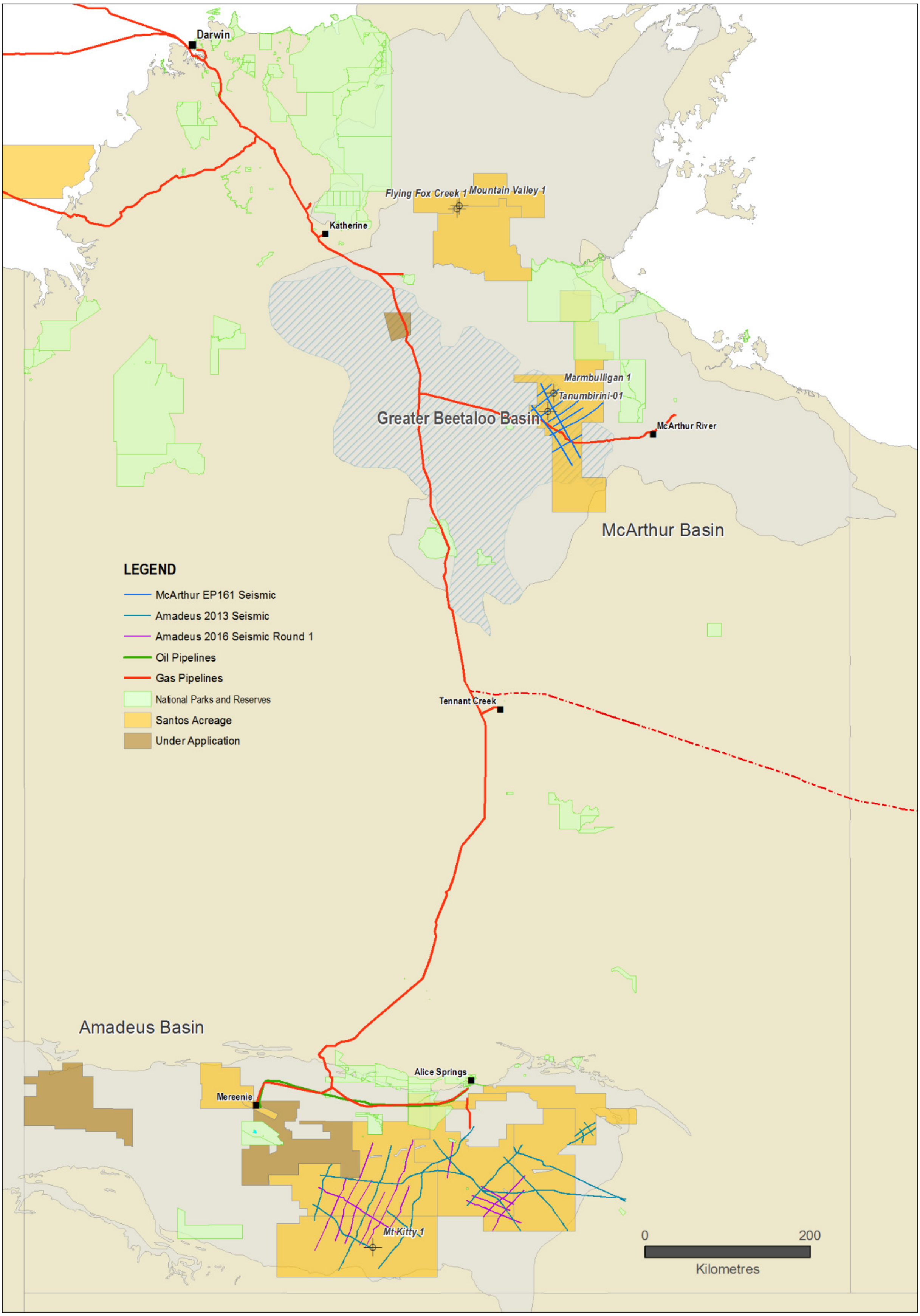
Exploration activities in the ventures to date have resulted in an improved understanding of the potential of both the McArthur and Southern Amadeus basins. There are encouraging indications, particularly in the McArthur Basin, that significant volumes of commercial shale gas may exist. In the Amadeus Basin, the primary targets are conventional resources and unconventional resources are not a target at the current time. In pursuing these gas opportunities in the Amadeus and McArthur basins, Santos has spent over $100 m net since 2013 (Santos, 2017).

Santos has prior experience in the NT as past operator of the Mereenie conventional gas field in the Amadeus Basin, where Santos has hydraulically stimulated 38 wells, including four in 2014. Similarly, Santos' extensive experience in the conventional gas fields of the Cooper Basin (SA) provides valuable insight for exploration, appraisal and development activities in the NT. To demonstrate relevance, a comparison of the target resource, well construction and hydraulic fracturing activities undertaken in the Cooper Basin (SA) and proposed in the NT are summarised in Table 2.

Table 2 Comparison of the target resource, well construction and hydraulic fracturing design relevant to the Cooper Basin (SA) and proposed in the NT

Feature	Cooper Basin, SA	Proposed, NT
Target formation depth	2,500 – 3,500 m	1,700 – 3,700 m
Target formation thickness	5 – 100 m	20 – 500 m
Well head design	15,000 psi rated	15,000 psi rated
Casing string design	12,000 psi rated	12,000 psi rated
Hydraulic fracture stimulation design	Multiple fracture stages using stimulation sleeves and composite bridge plugs for isolation	
Stimulation pump rates	8,590 L/min	9,540 L/min
Horsepower requirements	16,000 – 20,000 hhp	20,000 – 30,000 hhp
Fluid systems	Crosslinked fluids, linear gel or friction reduced water	Crosslinked fluids, linear gel or friction reduced water
Proppant	68,000 - 136,000 kg	68,000 - 136,000 kg
Separation between hydrocarbon zones and shallow aquifers	More than 1,500 m	More than 1,500 m
Cement imaging	Cement bond logs to determine quality prior to making decision to stimulate	
Pressure testing	Casing and annulus pressure tested prior to stimulation operation to simulate fracture conditions	
Well monitoring	Wells monitored real time via pressure transducers to ensure wellbore integrity during stimulation	
Well integrity management	Well integrity management system used to ensure regular casing and wellhead checks and risk mitigation	

Figure 19 Santos tenements in the NT



4.2 Exploration and appraisal activities

4.2.1 McArthur Basin/Greater Beetaloo Basin

The McArthur Basin covers a large part of the NT. Overlying a portion of the McArthur Basin is the Greater Beetaloo Basin, which is located south and east of Daly Waters, about 500 km south-east of Darwin (NT Government, 2016).

Following a review of Australian shale gas basins by Santos in 2011, the McArthur Basin was identified as having formations with the best characteristics for potential shale gas plays. In particular, the MesoProterozoic shales of the Velkerri and Kyalla Formations of the Greater Beetaloo and associated sub basins appeared to have many of the characteristics of successful US shale plays (organic richness (Total Organic Content (TOC)), thickness, depth of burial); although important shale reservoir characteristics such as gas content, porosity, gas deliverability and lateral extent of the Velkerri and Kyalla shales were poorly understood. The great age of the rocks (1,500 million years) was considered anomalous. The most prospective area for the shales was considered to be the Greater Beetaloo Basin where the shales were considered to be at optimal depths for shale gas exploitation (Santos, 2017).

Santos entered the McArthur Basin in 2012 via a farm-in to EP161, EP162 and EPE189 held by Tamboran Resources. In 2013, a 500 km seismic grid was acquired in EP161 that confirmed that the Velkerri and Kyalla shales probably extended eastwards at prospective depths and in an undeformed sequence from the central Greater Beetaloo Basin into what is now termed the ‘OT Downs Sub-basin’ (Santos, 2017) (Figure 20).

In 2014, Santos drilled the Tanumbirini well in EP161 to test the unconventional shale gas potential of the Kyalla and Velkerri shales. The well was drilled to a Total Depth (TD) of 3,946 m-RKB and encountered an expanded section of gas charged Velkerri shales. The Tanumbirini well was the first well to penetrate a full section of gas charged Velkerri shales in a basinal location (outside conventional closure) and verify the shale gas potential of the Velkerri formation.

A full core taken in the uppermost ‘C’ shale was complemented by an extensive suite of wireline logs and sidewall cores. These and other data gathered in the well confirmed gas charge and demonstrated that the shales had reservoir and brittleness characteristics similar to successful US shale plays. The Kyalla organic rich sales were also encountered but of limited potential compared to the Velkerri interval.

In Tanumbirini-1, the shallow aquifer of the Top Springs (Tindall) Cambrian limestone was encountered between depths of 52 m and 202 m. Between the Cambrian limestone and the Velkerri shales is a thick (3,000 m at this location) clastic sequence of shales and sandstones. The Bukalara Sandstone between 202 m and 582 m was underlain by the Neoproterozoic Hayfield mudstone and Jamison sandstone. Organic rich shales of the Kyalla formation were encountered from 1,943 m .The Moroak Sandstone, a saline aquifer, was encountered below 2,069 m.

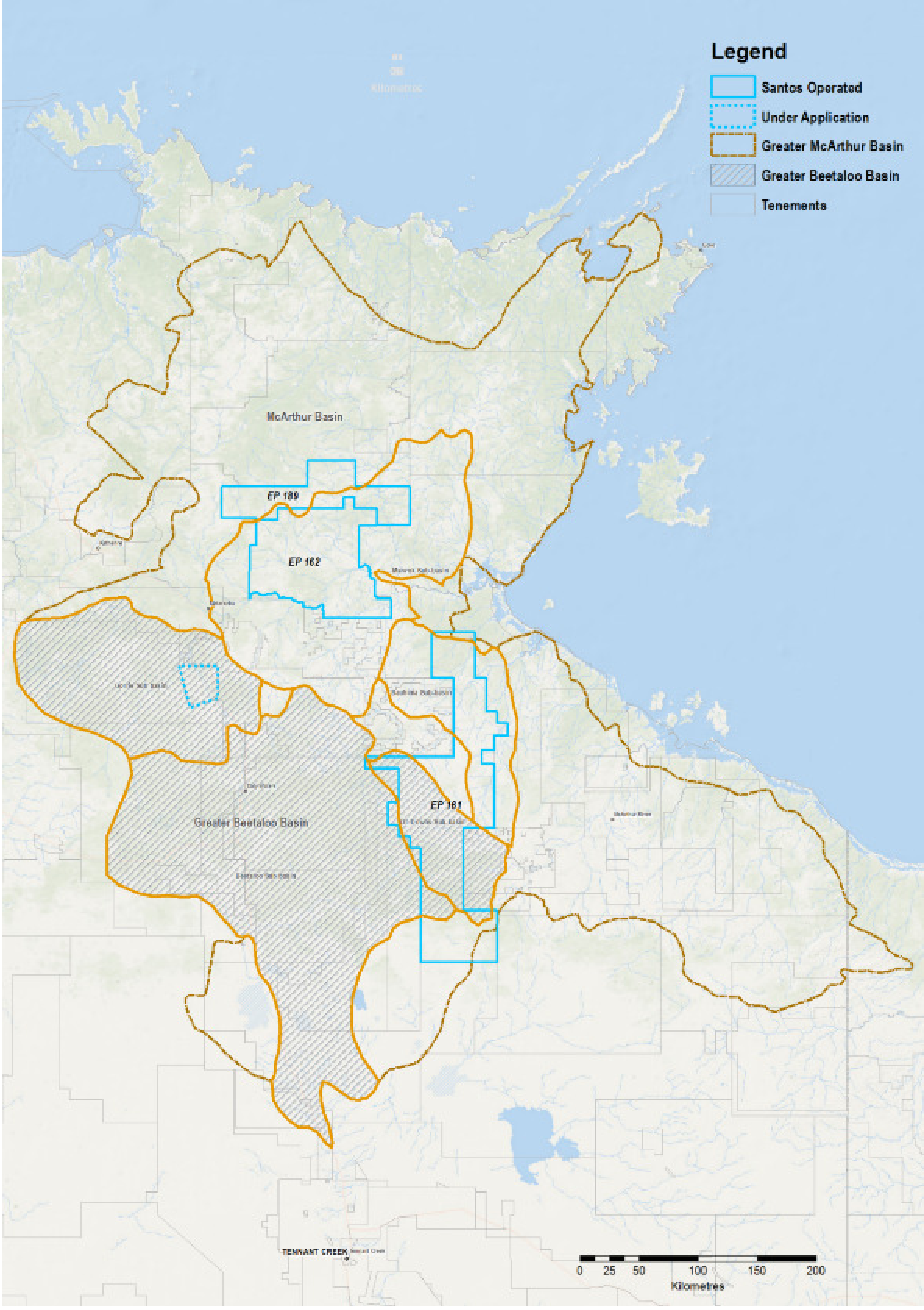
The organic rich shales of the Velkerri Formation (from the base upwards named A, B, and C)) were encountered between 3,200 m and 3,650 m. The uppermost C shale was encountered at 3,205 m (63 m thick), the B shale was encountered at 3,420 m (55 m thick) and the A shale was encountered at 3,583 m (52 m thick). The well reached the top of the Bessie Creek sandstone at the TD.

Gas shows while drilling through the Middle Velkerri shales, data obtained from the C shale core and an extensive suite of petrophysical logs indicate the organic rich shales TOCs (Total Organic Carbon wt % - a proxy for organic material content) range between 1 and 10%. Porosity (where gas is stored) is contained within the organic component of the shales.

Tanumbirini-1 demonstrated that the Velkerri shales are gas saturated in a basinal setting and are likely to be gas charged over large areas, although there is potential for leakage to have occurred where the shales subcrop at the basin margins.

In 2016, a stratigraphic well, Marmbulligan-1, was drilled 30 km north-northeast of Tanumbirini-1. At this location, the Velkerri shales are at relatively shallow depths (150-536 m – measured well depth) and outcrop to the east of the Marmbulligan-1 well location. The well successfully cored the full section of the Velkerri organic rich shales providing further information on the prospective interval also including confirmation of the lateral consistency of the shales and the presence of gas in the shales.

Figure 20 Santos tenements in McArthur Basin/Greater Beetaloo Basin



Using the data acquired, a preliminary Gas-In Place (GIP) calculation can be made. This calculation of GIP enables comparison with US shale plays and a preliminary assessment of likely volumetric scenarios available for development. In the EP161 permit, seismic data indicates the top of the Middle Velkerri shale interval is between depths of 1,200 m and 3,100 m (below ground level sub-sea) over an area of 700 square kilometres (1,800km^2). Shallower than 1,200 m the Velkerri shales are currently not considered prospective.

Using Tanumbirini-1 results, total volumes in place over the shale interval have been calculated at 163 billion cubic feet per section (P50) – per square mile – standard US measure) with 78 billion cubic feet per section (P50) for the B Shale (the best developed of the three shales). In EP161, the shales are prospective over an area of 700 sections, implying gas in place volumes in EP161 for the B shale alone in excess of 52 trillion cubic feet (P50).

Having established substantial gas in place volumes and demonstrated the positive mechanical properties of the shale intervals, the most significant remaining technical uncertainties relate the rate and volume of gas production from an optimally drilled and hydraulically fractured horizontal well.

No hydraulic stimulation of the Velkerri shales has been undertaken to date in EP161. A comprehensive appraisal program will be required before the commerciality of the resource can be established and a development plan scoped out and approved.

Marcellus play analogue

The Velkerri play displays similarities to the Marcellus shale play in the US, both in terms of host shale rocks and natural gas compositions.

The Marcellus Shale play is located in the Appalachian Basin and covers parts of New York, Pennsylvania, Maryland and West Virginia (Enerplus, 2014). The Marcellus play is now considered one of the US' largest shale gas resources (Lutz, Lewis, & Doyle, 2013). It is now the highest producing US shale play with a daily production in March 2017 of over 19 billion cubic feet per day – from 5 billion cubic feet per day in 2012 and virtually zero production in 2007 (EIA, 2017).

The Marcellus play is producing over a large area of Pennsylvania, a state that had seen little recent oil and gas activity prior to the shale gas boom. Two key producing areas are in southwest Pennsylvania, near the city of Pittsburg, and another in the northeast of the state. Liquid hydrocarbon rich plays are present in the southwest region and dry hydrocarbon gas (low liquid hydrocarbon content) plays prevalent in the northeast.

The Marcellus possesses many of the best characteristics of a shale play; high organic content (and thus generative potential and porosity), brittleness, benign tectonics with good seismic (i.e. easy to drill the target), overpressures, natural fractures and a consistent extensional stress regime.

The Velkerri shales display many similarities to the Marcellus shales although the Velkerri is still at an early stage of exploration with some critical facts not as well understood as in the Marcellus. The following similarities/differences are noted:

- Both shale reservoirs are black organic rich siliceous marine shales
- Thickness ranges are similar (somewhat thicker in the Velkerri)
- Total organic content (organic richness range similar but slightly higher in the Marcellus)
- Both shales brittle (although Velkerri 'tougher')
- Resource densities (billion cubic feet per square mile) similar magnitude
- Both liquids rich and dry gas plays are developed in the Marcellus
- Benign tectonics and good seismic
- Time span from organic maturation to present day significant (several 100 million years)
- Overpressures in the Marcellus – still largely unknown in the Velkerri
- Extensional stress regime in the Marcellus, strike slip to extensional in the Velkerri.

In summary, while there are many encouraging similarities between the Velkerri and the Marcellus shale, further testing of the Velkerri shales is required to demonstrate that the Velkerri can achieve a performance level approaching that of the Marcellus.

4.2.2 Amadeus Basin

The Amadeus Basin is located in the south of the NT and extends about 150 km into Western Australia (WA), covering an area of approximately 170,000 km^2 (Geoscience Australia, 2016).

In the southern Amadeus Basin, Santos farmed into acreage held by Central Petroleum. This acreage position currently consists of four permits (EP125, EP112, EP082 and EP105) over an area of 48,000 km2. In the northern Amadeus Basin exploration activity from the 1960s onwards had resulted in the drilling of a significant number of exploration wells and the discovery of three fields, Palm Valley, Mereenie and Dingo. The southern Amadeus Basin, in contrast, has seen very little exploration activity.

The current exploration campaign primarily targets conventional anticlinal traps where the Heavitree sandstone is sealed by the Gillen evaporite sequence and charged by Neoproterozoic source rocks. If a discovery were to be made in low permeability reservoir rock, hydraulic stimulation might be required to enhance productivity.

Following the first phase of seismic and the identification of a number of prospects and leads, Santos initiated the acquisition of a second infill seismic survey (1,300 km) in 2016 to firm up conventional gas prospects for exploration drilling in 2019.

4.3 Santos development scenario

Should a commercial gas resource be identified through exploration and appraisal, the ultimate goal of the development phase is to drill, fracture stimulate and produce wells into surface facilities in a manner that is economically viable. Some of the key drivers to achieve this are:

- Drilling the optimum number of wells (don’t space wells too tightly)
- Optimise fracture designs to create the most optimum pumping designs to reduce time, material requirements (including water and sand) while still achieving optimal well production rates
- Sizing facilities that matches the production profile and rate of drilling activity.

Given the lack of hydraulic stimulation and testing within the Santos tenements to date it is currently unknown whether the gas resource identified in EP161 is commercially viable. Therefore significant uncertainty exists in what a potential field development plan may comprise (if any) for Santos’ McArthur Basin acreage due to the early stage of play evaluation. At the request of the Inquiry Panel, a hypothetical development scenario has been prepared to provide an indicative development and is presented in the following section for indicative purposes only.

This submission scenario described assumes 326 development wells are required to produce into a facility with a plateau rate of 400 terajoules (TJ) per day (146 petajoules (PJ) pa). Development wells have a 2,000 m lateral length, with 34 fracture stimulation stages. Surface well pad spacing will be at approximately 4.4km intervals for a ten-well pad development scenario (one ten-well pad per 19.4km^2).

Development wells are likely to be directionally drilled from a central well lease area, with between four and ten wells per well lease. A comparison of the four-well and ten-well lease development options is outlined in Table 3. If four-well leases are used, 82 well leases in total are required; whereas only 33 well leases are required if ten-well leases are employed.

A ten-well pad requires additional surface area to house the wells and surface infrastructure and equipment (estimated to be 0.128 km^2 per ten-well lease) compared to a four-well lease (estimated to be 0.084 km^2 per four-well lease). However, due to the greater number of four-well leases required the total surface area required in the ten-well lease scenario is lower (4.2 km^2 for the ten-well lease scenario vs. 6.9 km^2 for the four-well lease scenario).

Table 3 **Comparison of four-well lease and ten-well lease area**

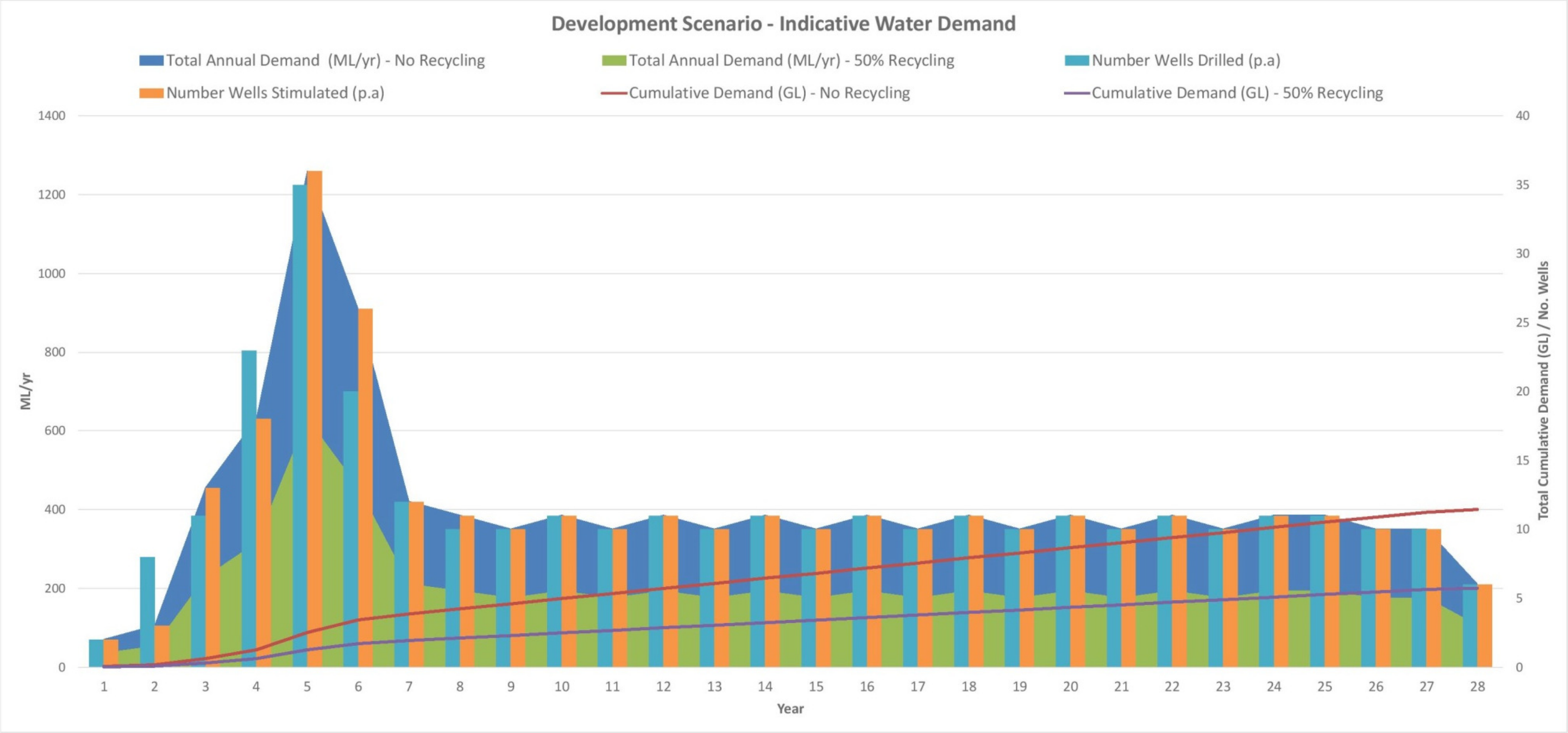
	Four-well lease	Ten-well lease
Estimated number of well leases	82	33
Estimated surface area (km^2) per lease, during drilling and stimulation phase	0.084	0.128
Estimated total surface area requirement (km^2) during drilling and stimulation phase	6.9	4.2
Estimated surface area (km^2) per lease, during production phase – post rehabilitation	0.033	0.039
Estimated total surface area requirement (km^2) during production phase – post rehabilitation	2.7	1.3

The disturbance calculations allow for the well lease, water storages, laydown areas, access tracks and gathering pipelines for both 4 wells per lease (82 well pads) and 10 wells per lease (33 well pads).

This shows that under this development scenario of 326 wells, the development footprint is 0.03 – 0.05% of the tenure area. Following well construction, the operational footprint is estimated to be 0.01 – 0.02% of the tenure area.

Based on the indicative Santos development scenario prepared for the purpose of this submission , the total water demand for well pad construction, drilling and hydraulic fracturing is approximately 5.5GL (assumes 50% flowback recycling) to 11 GL (no recycling) over 30 years Figure 21. This equates to an average of approximately 183ML/year to 367ML/year respectively. The underlying assumption is that 1ML of water is used to construct the well lease gathering line and drill a well and 1ML of water is used for each stimulation stage. Therefore a total of 35ML per well has been used.

Figure 21 Plot showing water use over time - 50% recycling and 0% recycling scenarios



Development concept of the four-and ten-well lease areas are shown in Figure 23 and Figure 24, respectively. It is difficult to see the well lease areas on the map as they each exploit only 0.16% and 0.15% of the surface area identified as prospective (1,800 km^2 area of Middle Velkerri shale interval, as per Section 4.2.1). It is important to note that this is the maximum surface area required during well construction (drill and fracture stimulation); production leases take up a much smaller surface area. The well lease area used for drilling and hydraulic fracturing operations is rehabilitated after use (as per Section 3.2.3.7).

It is important to note that this development scenario is hypothetical and for indicative purposes only. Significant uncertainty exists and a feasible outcome of no development remains, pending the outcome of further exploration and appraisal.

4.3.1 Surface Facilities

As a scenario surface facility installations are likely to be installed in two phases; Appraisal Gas Facilities and Full Field Development Facilities. Currently, the McArthur Basin shale gas resources carries a high risk of achieving commercial success, largely due to the unknown deliverability profile. Long term deliverability testing (i.e. two to three years of production data from a number of wells, e.g. >20wells) is crucial to address this risk. Long term production testing can be achieved by flaring wells, or installing appraisal gas production facilities to process and transport the gas to market. These facilities are a small-scale version of the full field development facilities and will utilise existing infrastructure where possible to maximise efficiencies. The appraisal gas facilities require a significant capital investment (in excess of A$100million in surface facility infrastructure, not including well construction costs). Shorter production tests (e.g. 90-180 days of flaring) from early Exploration-Appraisal wells is used to justify this capital investment.

The understanding of future well performance allows the Operator to establish an optimised field development plan on which commitment to execute the project (i.e. the full field development) is made. It is important to gather production profile decline information as soon as possible to enable full field development decisions to be made in a timely manner, with an appropriate understanding of project risk. Otherwise, decisions are likely to be deferred or made incorrectly.

The following subsections show that even during the construction phase, the surface disturbance is a very small portion of the area of interest (less than 1%). Furthermore, after construction, temporary facilities are rehabilitated, reducing the operational footprint.

4.3.1.1 Appraisal Gas Surface Facilities

The land area requirements for a small scale appraisal gas facility scenario, delivering up to 33 MMscfd of gas into the existing McArthur River Mine (MRM) and Amadeus Gas Pipeline (AGP) infrastructure has been estimated in the following section.

A pipeline corridor (15m right of way) is required for the gathering system network (i.e. flowlines, gathering lines and trunk lines), process facilities and access roads. An estimate of the land area requirements for the surface facilities has been estimated:

- Flow and gathering lines = 0.6 km^2
- Trunklines = 0.2 km^2
- Process facilities = 0.03 km^2
- Access Roads = 0.3 km^2
- Total = 1.1km^2

An additional 0.4 km^2 is required for temporary laydown facilities, which will be rehabilitated after the construction phase.

The surface disturbance estimate was conducted assuming nine well pads were connected to the Appraisal Gas Facilities. The surface disturbance will increase for an expanded Exploration-Appraisal program. Expanding the facility size up to 100 TJ/d (36.5 PJ pa) for example gives greater capacity to conduct production testing from a greater number of wells and subsequently reduce project risk.

4.3.1.2 Full Field Development Surface Facilities

The full field development scenario facilities are an expanded version of the Appraisal Gas Facilities discussed in Section 4.3.1.1.

The land area requirements for a 400 TJ/d development (146 PJ pa), with ten-well pads at 480acre downhole well spacing is presented below.

- Flow and gathering lines = 4.0 km^2
- Trunklines = 88.5 km^2
    - Export pipeline to Wallumbilla assumed to supply gas to the East coast. This pipeline is assumed to be buried.
    - 24.1km^2 of trunkline is in the NT, 64.4km^2 in QLD
- Process facilities = 0.2 km^2
- Access Roads = 2.1 km^2
- Total = 94.9 km^2

An additional 94.9 km^2 is required for temporary laydown facilities (25.8 km^2 in the NT, 69.1 km^2 in QLD), which will be rehabilitated after the construction phase. This also includes a temporary water handling facility to manage water for fracture stimulation purposes (i.e. flow back water, which can be treated and used as a source for subsequent fracture stimulation treatments).

Therefore, the total land requirements for the Reference Case (i.e. 400 TJ/d, 326 wells, 33 ten-well pads) for the construction phase is estimated to be:

- Wells = 2.7 km^2
- Permanent Surface Facilities (in the NT) = 29.5 km^2
- Temporary Facilities (in the NT) = 25.8 km^2
- Total (in the NT) = 58 km^2
    - Note a significant portion of this is outside of the Santos' 1800 km^2 area of interest in the McArthur Basin (associated with the construction and route of the export pipeline)

The total land requirement for the same case during the production phase is significantly reduced:

- Wells = 1.0 km^2
- Permanent Surface Facilities (in the NT) = 29.5 km^2
- Total (in the NT) = 31.5 km^2
    - Note a significant portion of this is outside of the Santos' 1800 km^2 area of interest in the McArthur Basin (associated with the route of the export pipeline)

Figure 22 presents a conceptual schematic of the Full Field Development Facilities. The concept assumes a Central Processing Facility, with six trunk lines connected to it. Each trunk line has five pads teeing into them, with an additional three well pads tied into the central processing facility.

Figure 22 Full Field Development conceptual schematic

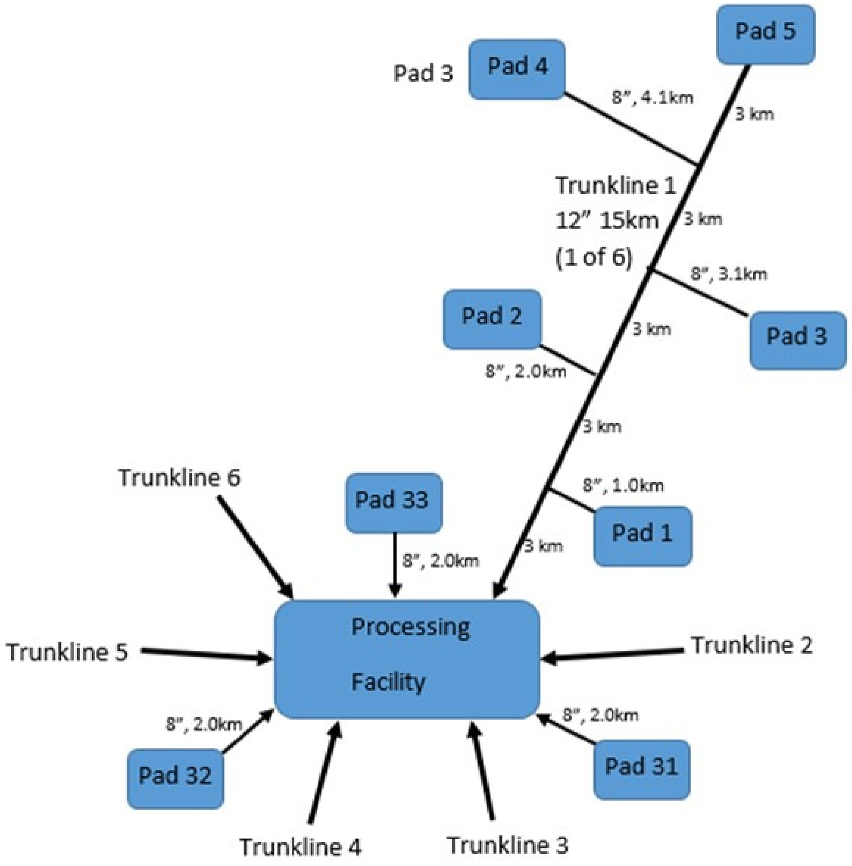


Figure 23 Four-well lease development concept (to-scale)

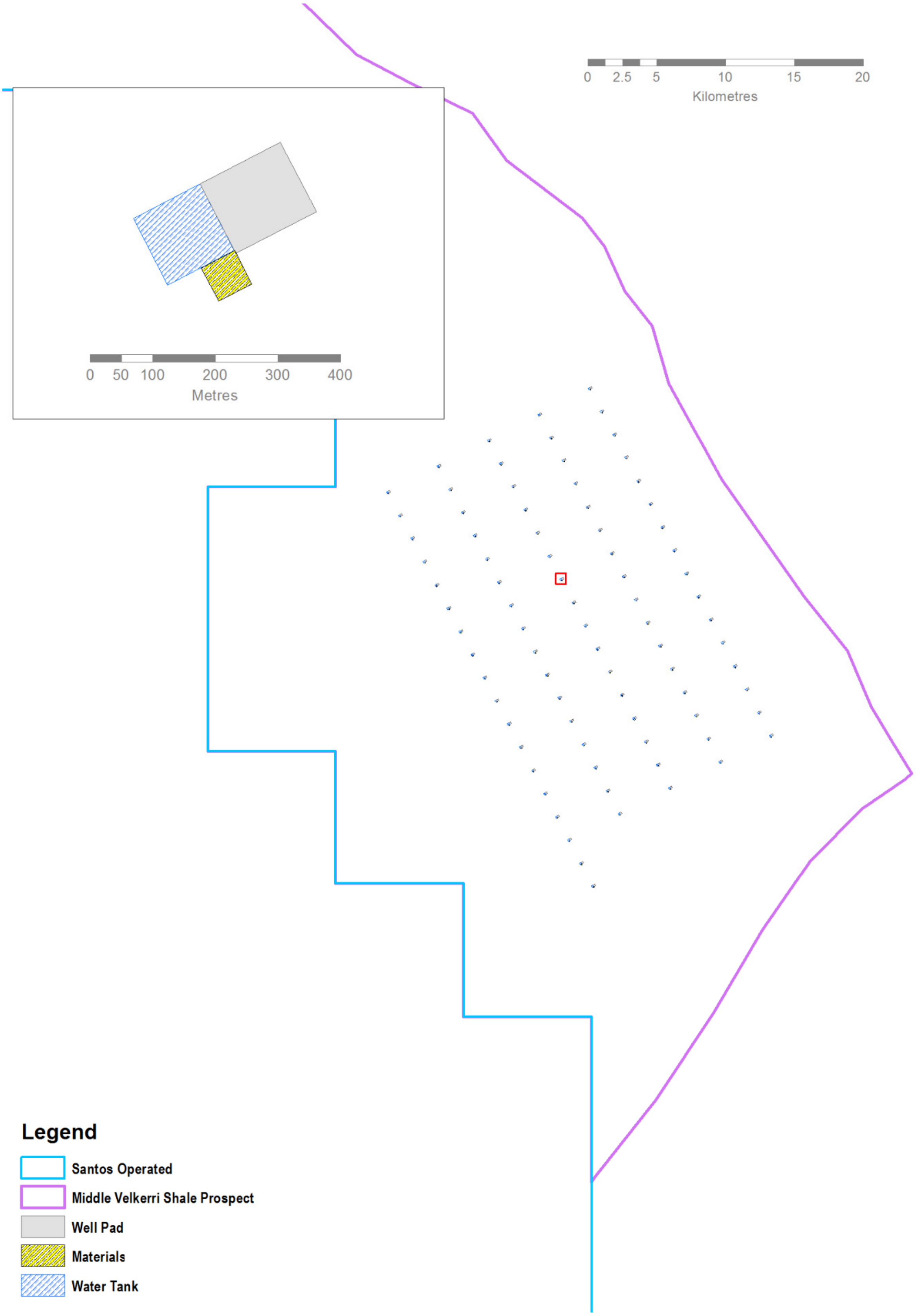
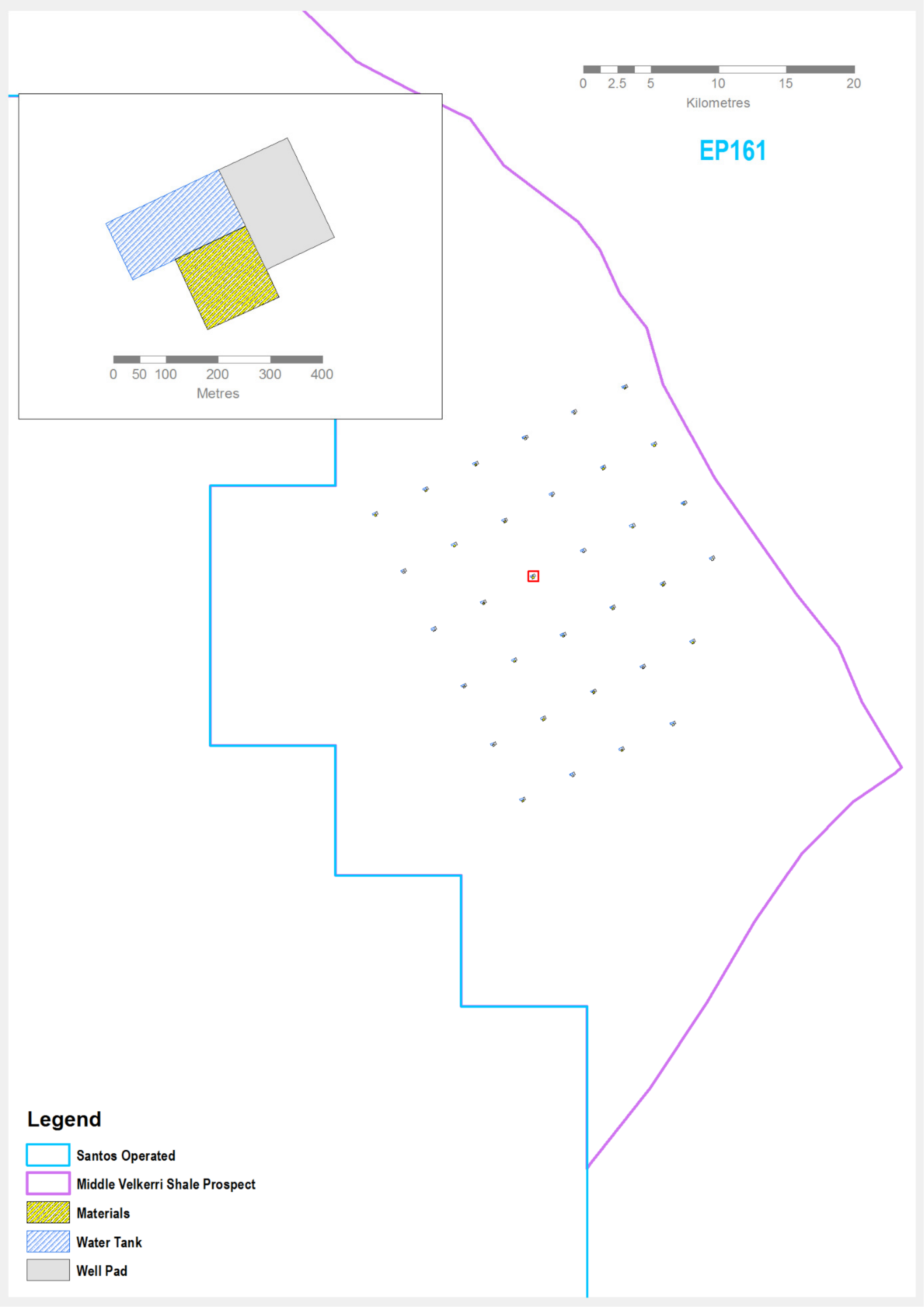


Figure 24 Ten-well lease development concept (to-scale)



5.0 Setting of Santos tenements

The following sections provide the background to social and environmental aspects related to the Santos tenements, in particular, the focus area within EP161. This section describes the physical, biological and social environment, where the environment being defined comprises land, air, water, organisms and ecosystems.

5.1 Land resources

This section describes the land use and land resources relevant to the target area within EP161. Land-related risk themes are considered in Appendix A (Risk themes mitigation matrix).

5.1.1 Land use

The target area in EP161 predominantly lies within Roper Gulf Local Government Area, with a small area in the southern portion lying within Barkly Local Government Area.

Land use within the target area of EP161 is pastoral. Two pastoral leases (landholders) account for 100% of the target land area with cattle grazing representing the principal pastoral activity. The 'Tanumbirini' homestead is located in the centre of the area. Tenure and land use of the target area of EP161 is depicted in Figure 25.Tanumbirini Station is a 5,000 km^2 cattle grazing property located 420 km southwest of Katherine in the McArthur Basin.

Santos has an executed Landholders Access and Compensation Agreement in place (Tanumbirini Station leaseholders) which prescribes the landholders consent to the petroleum activities conducted by Santos as well as prescribed access arrangements, the obligations of the operator along with an agreed compensation regime based on deprivation/impact to land.

Tanumbirini-1 and Marmbulligan-1 wells are both located on Tanumbirini Station and during these drilling programs Santos ensured compliance by engaging early, involving the Station leaseholders in the planning of activities, maintaining ongoing communication and ensuring agreed access arrangements such as the installation of grids at agreed locations and the upgrading and maintaining of roads affected by the programs.

Santos works with the Station leaseholders to ensure activities have minimal disruption to pastoral activities along with ensuring that rehabilitation of affected areas is undertaken as per the terms of the access agreement.

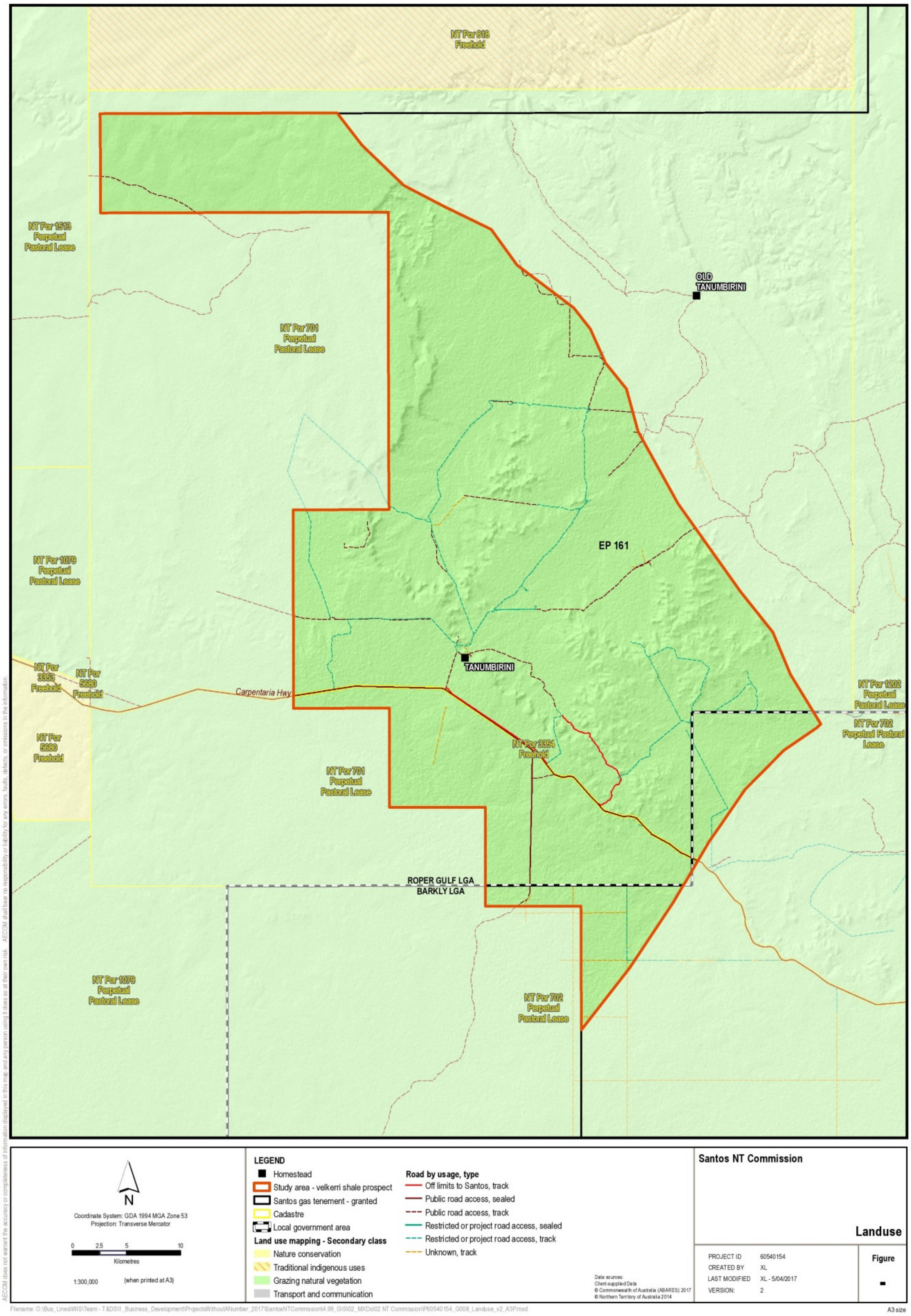
5.1.2 Topography and soils

The topography is predominantly flat lying; the landform comprises gently undulating plains and valleys that drain outcropping Proterozoic rocks towards the Gulf of Carpentaria.

Soils are dominated by tenosols, kandosols and vertosols with rudosols associated with more rugged rock terrain.

- Tenosols are weakly developed or sandy soils, commonly shallow (slightly more developed than Rudosols), although they can include the deep sand dunes of beach ridges, granitic soils and sand dunes of deserts; show some degree of soil profile organisation (minor colour or soil texture changes in subsoil). Due to poor water retention and low fertility, tenosol soils are mainly suited to grazing of native pastures (CSIRO, 1996).
- Kandosols are massive and earthy soils (formerly red, yellow and brown earths) that are widespread across the Sturt plateau regions. Mostly well drained, permeable soils with low fertility used for extensive agriculture; grazing lands may be susceptible to surface soil degradation (CSIRO, 1996).
- Vertosols are cracking clay soils which may or may not be poorly draining (Santos, 2016) mainly suited to grazing of native pastures (CSIRO, 1996).
- Rudosols are very shallow soils or those with minimal soil development and include very shallow rocky and gravely soils across rugged terrain.

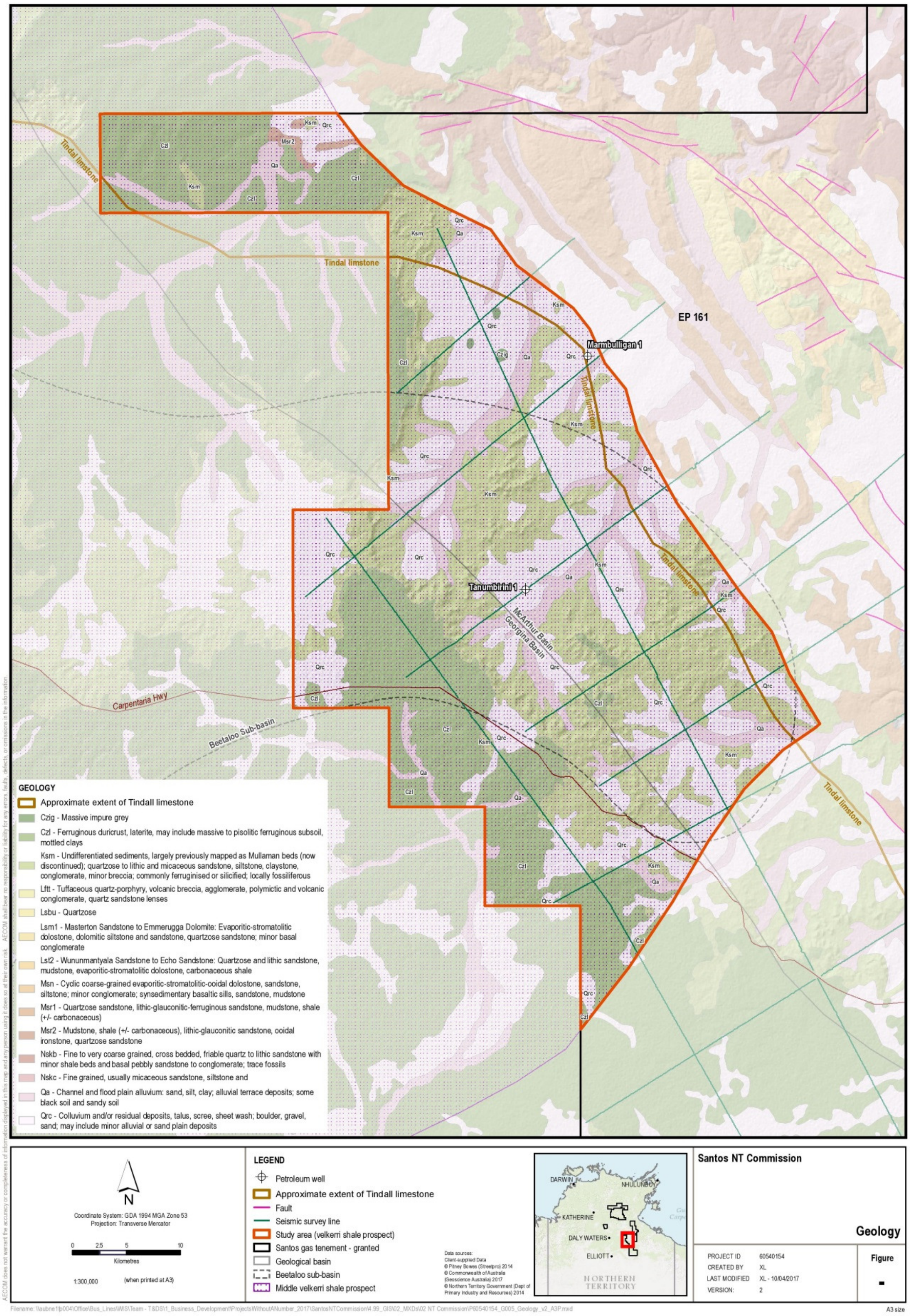
Figure 25 EP161 target area tenure and land use



5.1.3 Regional geology

Figure 26 illustrates the geology of the study area.

Figure 26 Geology of the Study Area



The Palaeo-to Mesoproteozoic McArthur Basin is exposed over an area of about 180,000 km^2 in the northeast Northern Territory. Phanerozoic strata of the Georgina, Carpentaria and Arafura basins unconformably overlie the McArthur Basin succession, with McArthur Basin strata extending southwest beneath Phanerozoic cover to the Tomkinson Province of the Tennant Region (Ahmad, Dunster, & Munson, 2013).

The McArthur Basin contains an unmetamorphosed and relatively undeformed succession of sedimentary and minor volcanic rocks with a preserved thickness of up to 10 km (Plumb & Wellman, 1987). In the southern McArthur Basin, this succession has been subdivided, in ascending stratigraphic order, into the Tawallah, McArthur, Nathan and Roper groups. The rarity of limestone distinguishes the Roper Group lithologically from the underlying sedimentary successions of the McArthur Basin (Munson, 2014).

The regionally extensive Roper Group is widespread throughout the McArthur Basin (Figure 28). The Roper Group comprises six upward-coarsening cyclic successions of mainly marine mudstone alternating with sandstone (Ahmad, Dunster, & Munson, 2013). Evidence for a marine setting includes the presence of glauconite and marine microfossils at numerous stratigraphic levels, the high compositional maturity of the sandstones, and the lateral continuity of sedimentary facies. The Roper Group succession accumulated over a period between 1.49 and 1.43 billion years ago with a later mafic sill and dyke intrusion event occurring 1.32 billion years ago.

In a large-scale sense, the Roper Group succession is broadly wedge shaped the preserved thickness ranging from greater than 3,000 m in the Greater Beetaloo Basin, to 1,500 m in the Maiwok and Bauhinia sub-basins (Figure 27 and Figure 28). There is no evidence for continental slope or deep basin deposits as are typical outboard of present-day open-marine continental shelves (Munson, 2014).

In the Greater Beetaloo basin, a greater rate of subsidence is indicated by greater thickness of strata, but the succession of facies is the same in other areas of deposition indicating that rates of deposition were generally equivalent to rates of subsidence Figure 27. The component sub-basins of the Greater Beetaloo basin are largely flat-lying depocentres with uplifted erosional margins.

Two significant sandstone units in the area of interest are the Bessie Creek Sandstone and the Moroak Sandstone. The Bessie Creek Sandstone is located below the lower Velkerri Formation shales and the Moroak Sandstone is above the upper Velkerri Formation shales. Both sandstones are saline aquifers. Similar, less well developed sandstones are present in the Kyalla Formation. The prospective middle Velkerri Formation shales are bounded above and below by low permeability, non prospective shales of the lower Velkerri Formation (below) and upper Velkerri Formation (above).

Unconformably overlying the Roper Group succession in the Greater Beetaloo Basin is an unnamed group comprising the Neoproterozoic (circa 800 million years ago). Jamison Sandstone and Hayfield Mudstone units (Figure 27 and Figure 29).

This package of Neoproterozoic sediments is in turn unconformably overlain by a relatively thin Georgina Basin succession that includes the Ediacaran Bukalara Sandstone, the Early Cambrian Antrim Plateau/Helen Springs Volcanics and the Middle Cambrian Top Springs/Tindall Limestone.

The Tindall Limestone is a significant regional fresh water aquifer that can attain thicknesses of 200 m and is present in the near subsurface over much of the Greater Beetaloo Basin. The Basin is topped by a thin continuous veneer of undifferentiated Cretaceous sediments of the Carpentaria Basin.

Figure 27 South-north Greater Beetaloo Basin schematic cross-section (Close et al, 2017)

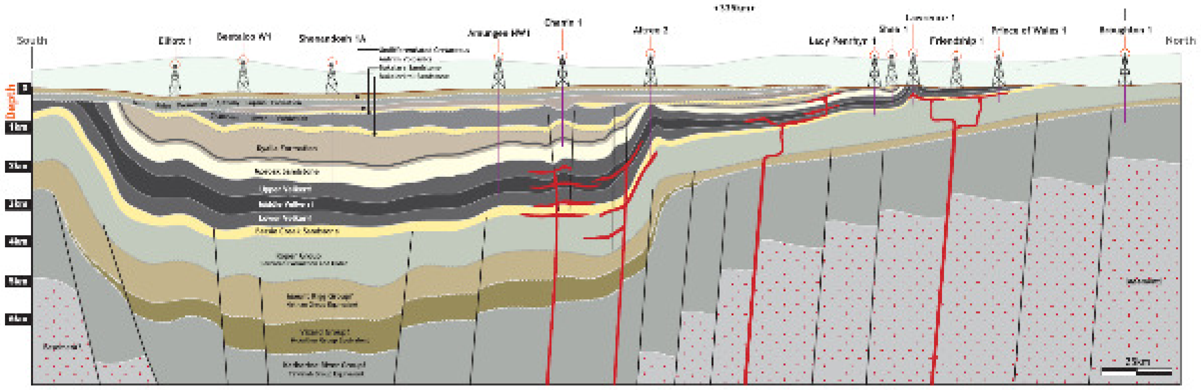


Figure 28 McArthur Basin and component Roper Group sub-basins

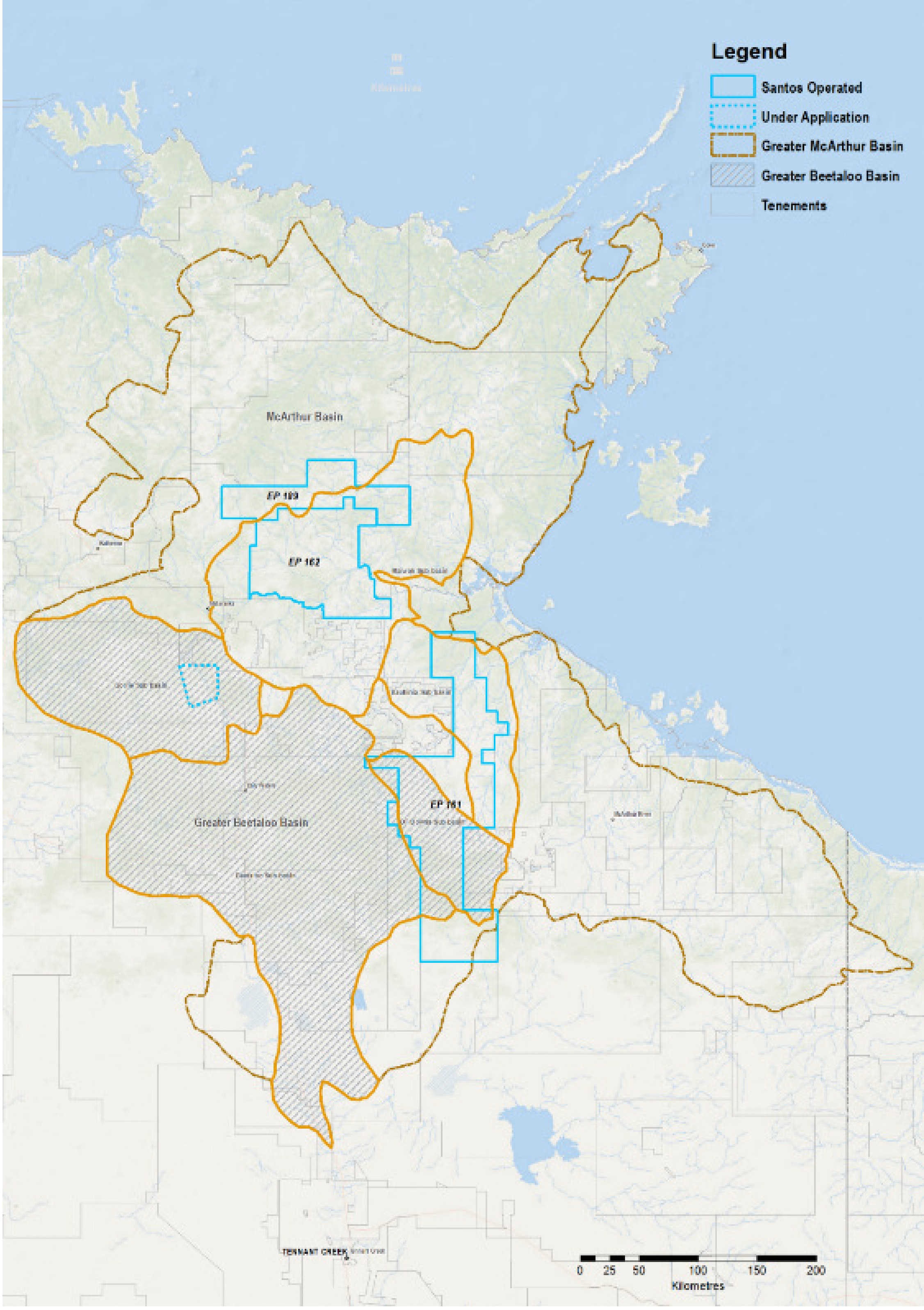


Figure 29 Northwest-southeast geological cross section across the OT Downs Sub-basin, Greater Beetaloo Basin

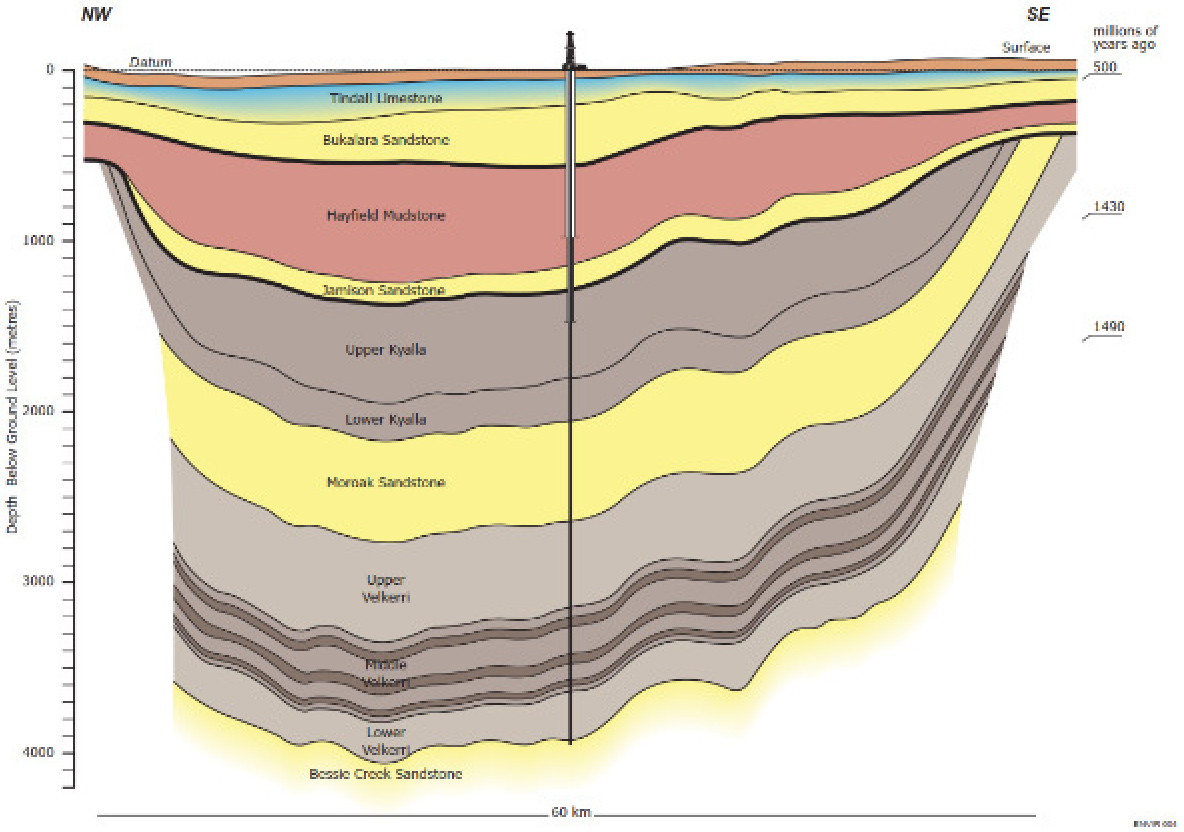


Figure 29 displays a cross section through the Tanumbirini-1 well location. The section demonstrates the separation between the prospective middle Velkerri Formation shales and the Tindall Limestone groundwater aquifer.

Initial petroleum exploration in the Greater Beetaloo Basin in the late 1980s and early 1990s targeted conventional accumulations in the Neoproterozoic Jamison Sandstone, and the Moroak and Bessie Creek sandstones of the upper Roper Group (Lanigan, Hibbird, Menpes, & Torkington, 1994). This work, including regionally extensive 2D seismic surveys and exploration wells, confirmed the presence of thick, laterally extensive and thermally mature, organic rich hydrocarbon source rocks in the middle Velkerri and lower Kyalla formations of the upper Roper Group. These organic rich rocks are now recognised as shale gas reservoirs hosting substantial volumes of natural gas.

The maturity levels of the Kyalla and Velkerri formations within the Greater Beetaloo Basin demonstrate that, as well as the hydrocarbons that are now retained in the shales, very large volumes of oil and gas have been generated and migrated out of the shales. These hydrocarbons are either trapped in the subsurface as discrete accumulations, dissolved in connate water in the deeper sandstone aquifers or are migrating over geological time to the surface of the earth or into the atmosphere via faults or subcropping strata.

Evidence for these migrated hydrocarbons has been found in several exploration wells.

Minor gas was encountered in the Cambrian Antrim Volcanics in Ronald-1 at 361-368.0m. Minor amounts of gas were flowed from the Jamison Sandstone in Jamison-1 and gassy formation water has been encountered in or recovered from the Jamison and Moroak Sandstones at a number of locations. Oil shows have also been found in shallower formations in several wells (e.g. below 638m in Balmain-1).

Along the basin margins where subcropping strata provide escape routes for migrating hydrocarbons, minor gas may be encountered in waterbores. Alternatively natural gas may result from bacterial breakdown of organic matter present in organic rich shales in the shallow sub-surface. An example in the Greater Beetaloo Basin is a water bore on Gilnockie Station that encountered gas (ABC, 2016) relatively close to the sub-crop edge of the Velkerri Formation. The presence of gas bubbles exuding from middle Velkerri Formation shales in the Marmbullligan-1 well on the eastern basin margin confirms the presence of natural gas in the shallow subsurface.

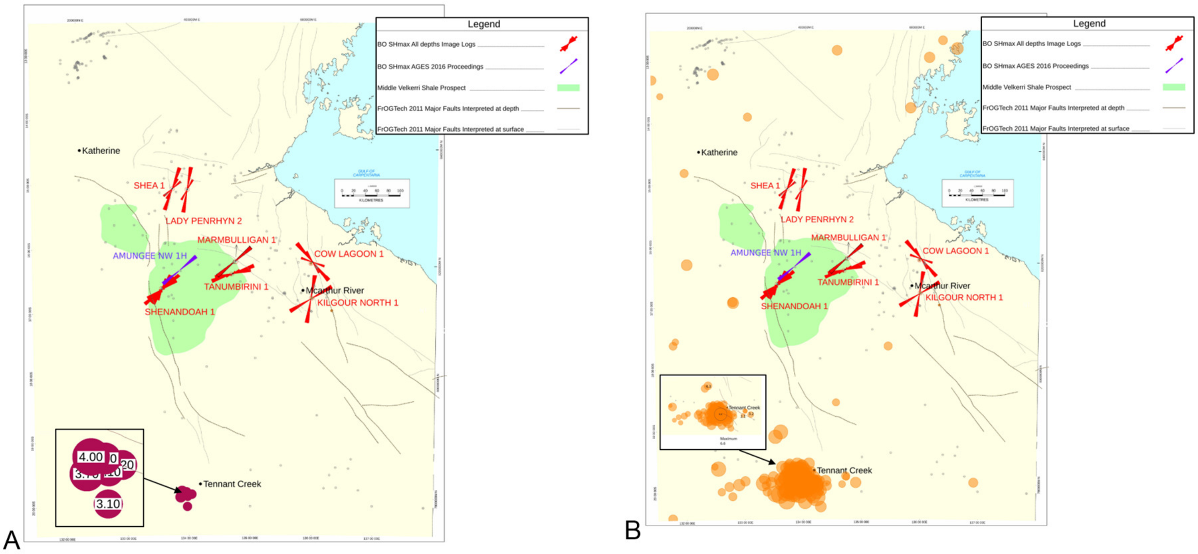
The pre-development evidence for the presence of shallow hydrocarbons in the Greater Beetaloo Basin demonstrates that this is a natural phenomenon. Extending baseline surveying and monitoring away from areas of planned activity to the basin margins should capture the presence of any detectable natural gas emissions associated with gas bearing, subcropping strata.

5.1.4 Seismicity

Australian earthquakes occur in a “stable” continental region, so are infrequent compared to those in plate boundary settings. In a typical region an event is only felt on average each 5 to 10 years. The whole continent experiences about 600 recorded events each year, with 2 events of magnitude greater than 5 on the Richter scale (Leonard, 2008). Moderate magnitudes occur within 25 km every few thousand years. Large magnitudes occur within 50 km each 20,000 to million years (Gibson & Sandiford, 2013).

Official records on seismic activity in the Northern Territory go back to February 1986. There are also newspaper and other unofficial reports of earthquake activity in the Northern Territory dating back to 1869 (Jones, 1988a), (McCue K. , 1990a). The Tennant Creek Earthquake in 1988 is one of the highest magnitude events located in Australia at 6.7 M (Evans, 1988). Seismic activity data measured by Geoscience Australia (2017) has been mapped for the past year and past 50 years Figure 30. It has been demonstrated that all seismic activity has occurred at locations well away from the Velkerri shale play. There are no major faults within the Velkerri Shale play limits; those that exist at the boundaries can be avoided when locating wells.

Figure 30 Stress orientation, mapped faults and measured seismic activity last 12 months (A) and last 50 years (B)



5.2 Water resources

This section describes the water resources relevant to the target area within EP161. Water-related risk themes are considered in Appendix A (Risk themes mitigation summary).

5.2.1 Surface water

The majority of catchments within EP161 drain north-easterly towards the Gulf of Carpentaria. Major rivers include Limmen Bight River, October Creek and Cox River.

The highest flow for these rivers occurs during the wet season, predominantly due to cyclones and monsoonal rainfall. Approximately 90% of the rainfall occurs during the wet season (AECOM, 2016), and leads to highly variable stream flows in catchments located within the region (Santos, 2016). Smaller streams such as the Lansen, Inacumba, Tanumbirini and Lagoon Creeks are largely ephemeral and usually run dry during the dry season. Ephemeral streams are subject to short flow duration and high turbidity.

Water usage in the Limmen Bight river region includes bores and rainwater, and supplies water to cattle from bores, dams and waterholes (Zaar 2009).

There is also a range of small waterholes associated with sinkholes and minor depressions in the generally flat landscape. Isolated waterholes have been identified in the Cox and upper Limmen Bight Rivers associated with groundwater discharge and fractured and weathered rocks (Zaar 2009). Riparian zones of these rivers and wetlands are generally in fair to good condition, affected mostly by access by livestock and feral animals and weeds.

A number of hot spring have been identified on Tanumbirini Station, identified in Table 4.

Table 4 Hot springs on Tanumbirini Station

Site	Site Name	pH	TDS mg/L	Hardness mg/L	Calcium mg/L	Magnesium mg/L	Sodium mg/L	Chloride mg/L
G9055076	Hot spring R/B Lagoon Ck	6.8	350	77	20	7	76	155
G9055086	Very hot spring on tributary to Beauty Creek	7.2	310	108	31	7	48	97
G9055081	Spring area to upper Cox River, Tanumbirini Station	6.8	280	58	15	5	59	119

Significant construction activities can be timed to avoid wet season constraints. Stream crossings (if required) can be undertaken at times of no flow given the ephemeral nature in the area.

5.2.2 Groundwater

The hydrostratigraphy of the Beetaloo Basin is included in Table 5. This allows for the identification of usable groundwater resources (identified as aquifers), aquitards and separation between target shale formations and the usable groundwater resources. The table includes the geological units comprising the Roper Group to surface (Section 5.1.3).

The main groundwater resources are associated with the Gum Ridge Formation and the Anthony Lagoon Beds, which make up the Cambrian Limestone Aquifer.

Proterozoic age fractured rock aquifers are used in areas across the Beetaloo Basin where the Cambrian Limestone Aquifer is absent. The Bukalara Sandstone is an example of a productive local fractured rock aquifer.

These “shallow” (younger sediments) groundwater resources are separated from the target shale formation, the Velkerri Formation, by the Hayfield Mudstone, Jamison Sandstone, Kyalla Formation, and Moroak Sandstone.

The Velkarri Formation is a substantial shale and siltstone sequence, up to 879 m thick, which is extensive across the entire Beetaloo Basin. This formation provides a competent seal for the underlying Bessie Creek Sandstone, i.e. this formation is a regional aquitard, which isolates the underlying Roper Group from the overlying Cambrian and Mesozoic systems.

The Moroak Sandstone, comprising mostly cemented fine to medium sand, which is fractured in places. The secondary permeability, as a result of fracturing, ranges from 0.05 to 0.23 m/day. There are no recorded water bores in the Moroak Sandstone within the Beetaloo Basin.

The Kyalla Formation is a continuous aquitard across the Beetaloo Basin, some 700 m thick. This predominant mudstone sequence retards vertical groundwater flow.

The distribution of the Jamison Sandstone is restricted to the Beetaloo Basin and has an average thickness of 100 m. Permeability is low within the fine grained sandstone sequence, <0.1 m/day. No groundwater intersections have been recorded from water bores intersecting this unit, however, local aquifers could form where fracture development has enhanced groundwater potential.

The Hayfield Mudstone is a fine grained mudstone and claystone sequence, some 230 m in thickness. This unit acts as a continuous aquitard across the Beetaloo Basin. This unit is unaffected by deeper seated faults but where it contains large sandstone inliers permeability can be up to 0.02 m/day.

It is therefore recognised that there is a thick sequence of low permeable sediments between the target shale units and the Cambrian Limestone Aquifer.

Table 5 Hydrostratigraphy (source: CloudGMS, 2015)

Basin	Formation	Lithology	Thickness	Aquifer Classification	Comment
-	Cenozoic deposits	Laterite, limestone, alluvial	< 25 m	None - unsaturated	Perched seasonal water tables in wet season
Carpentaria	Undifferentiated Cretaceous	Siltstone, claystone, sandstone	0 – 130 m	Aquitard with local aquifers	Basal sandstone forms local aquifer with restricted recharge / sustainable yields
Georgina	Anthony Lagoon Beds	Fractured dolomite, dolomitic sandstone, fine grained sandstone	0 – 205 m	Regional aquifer	Karst aquifer (dolomite)
	Gum Ridge Formation	Fractured and karstic limestone	0 – 295 m	Regional aquifer	Karst aquifer (limestone)
	Antrim Plateau Volcanics	Basalt with minor interbedded sandstone	0 – 440 m	Regional aquitard	Thick undeformed basalt aquitard
	Bukalara Sandstone	Jointed sandstone and minor siltstone (discontinuous)	0 – 73 m	Local aquifer	Secondary permeability due to jointing
Beetaloo	Hayfield Mudstone	Mudstone, claystone with sandstone interbeds	0 – 450 m	Aquitard with local aquifers	Mudstone aquitard with minor sandstone aquifers
	Jamison Sandstone	Fine grained quartz sandstone	0 – 160 m	Local aquifer	Requires secondary permeability and porosity for aquifer development
	Kyalla Formation	Silty mudstone with thin siltstone and sandstone beds	0 – 776 m	Aquitard	Thick mudstone unit
	Moroak Sandstone	Fractured quartz sandstone	0 – 483 m	Local aquifer	Requires secondary permeability and porosity for aquifer development
	Velkerri Formation	Mudstone, claystone, siltstone	709 – 879 m	Regional aquitard	Continuous across basin, shale gas target
	Bessie Creek Sandstone	Fine grained silicified quartz sandstone	442 m	Local aquifer	Requires secondary permeability and porosity for aquifer development
	Corcoran Formation	Mudstone, siltstone and fine interbedded sandstone	> 40 m	Aquitard	Inferred aquitard based on dominant lithology
	Abner Sandstone	Massive quartz sandstone	660 m (inferred)	Local aquifer	Weathered outcrop provides groundwater resource

Basin	Formation	Lithology	Thickness	Aquifer Classification	Comment
	Crawford Formation	Fine micaceous sandstone with interbedded siltstone	200 m (inferred)	Possible aquifer	No data
	Mainoru Formation	Siltstone, mudstone, shale with minor interbedded sandstone	730 m (inferred)	Aquitard	Based on dominant lithology
	Limmen Sandstone	Fine to coarse grained sandstone with interbedded siltstone	330 m (inferred)	Possible aquifer	Based on lithology

5.2.2.1 Shallow Groundwater Resources

The most comprehensive investigation of water resources in the Beetaloo Basin region was undertaken by the NTG Water Resources Division (WRD), currently part of the Department of Land Resource Management (DLRM). Between 1996 and 2009 WRD completed three water resource assessment projects: the Barkly Tablelands (Tickell, 2003) , the Sturt Plateau (Yin Foo & Matthews, 2000) and the Gulf Study (Zaar, 2009). Combined, these studies map the shallow groundwater resources over approximately 95% of the Beetaloo Basin.

Identified high yielding aquifers within the region include the Cambrian aged Anthony Lagoon Beds and Gum Ridge Formation (both limestone aquifers which make up the Cambrian Limestone Aquifer), located within the central region of EP161. The Gum Ridge Formation forms an extensive area from Tennant Creek to Mataranka, with a regional flow system that flows roughly northward towards Mataranka (URS, 2015).

5.2.2.2 Groundwater uses

Baseflow

During the dry season aquifers within the Roper River catchment provide some 95,000 to 126,000 ML/yr as baseflow through the river bed and springs. The baseflow is sourced from the Cambrian aged limestone aquifer(s) in the headwaters of the perennial Roper River.

Little or no baseflow to the Hodgson, Strangeways, and Elsey Creek rivers occurs due to the underlying (aquitard) geology.

Community water usage

An estimate of groundwater usage by communities in the Beetaloo Basin, based on per capita water consumption, is estimated to be 1,800 litres per person per day.

Based on town populations, community (groundwater) supplies are in the order of 400 ML/year.

Stock and Domestic water usage

Due to data paucity regarding stock numbers a rough estimate of stock water use was compiled assuming a stocking rate of 4 to 5 head per km^2. Using this stocking rate and an area of 60,000 km^2 there is approximately 240,000 to 300,000 cattle currently being watered from the Cambrian aged limestone aquifer(s). Applying an average consumption rate of 50 litres/head/day, the stock water use is estimated at 4,380 to 5,475 ML/year.

5.2.2.3 Groundwater quality

Groundwater quality data for samples collected during exploration drilling is included in Table 6.

Table 6 Groundwater quality in the Beetaloo Basin

Aquifer	EC (µS/cm)	pH (mean)	Sodium mg/L Na	Potassium mg/L K	Calcium mg/L Ca	Magnesium mg/L Mg	Bicarbonate mg/L HCO_3	Sulfate mg/L SO_4	Chloirde mg/L Cl
Cambrian Limestone Aquifer									
Gum Ridge Formation	350 – 3,000	7.5	2 - 438	2 - 90	16 - 204	11 - 116	56 - 676	6 - 650	2 - 620
Anthony Lagoon Beds	670 – 6,470	7.6	9 - 381	9 - 98	12 - 303	25 - 134	86 - 525	18 - 979	16 - 570
Fractured Rock Aquifer									
Bukalara Sandstone	130 – 2,130	7.4	14 - 224	3 - 36	3 - 120	2 - 98	40 - 447	8 - 665	9 - 340
Antrim Plateau Volcanics	400 – 1,840	7.9	43 - 166	2 - 6	8 - 76	2 - 64	178 - 380	17 - 176	4 - 327
Proterozoic	180 –	7.5	2 - 376	1 - 32	6 - 89	7 - 84	74 - 493	5 - 325	2 - 427

Aquifer	EC (µS/cm)	pH (mean)	Sodium mg/L Na	Potassium mg/L K	Calcium mg/L Ca	Magnesium mg/L Mg	Bicarbonate mg/L HCO_3	Sulfate mg/L SO_4	Chloirde mg/L Cl
outcrop	2,320								
Formation water									
Roper Group	32,000 – 159,000	-	6,100 – 64,500	300 – 1,500	1,400 – 30,000	600 – 5,900	30 - 50	40 - 800	13,500 – 147,800

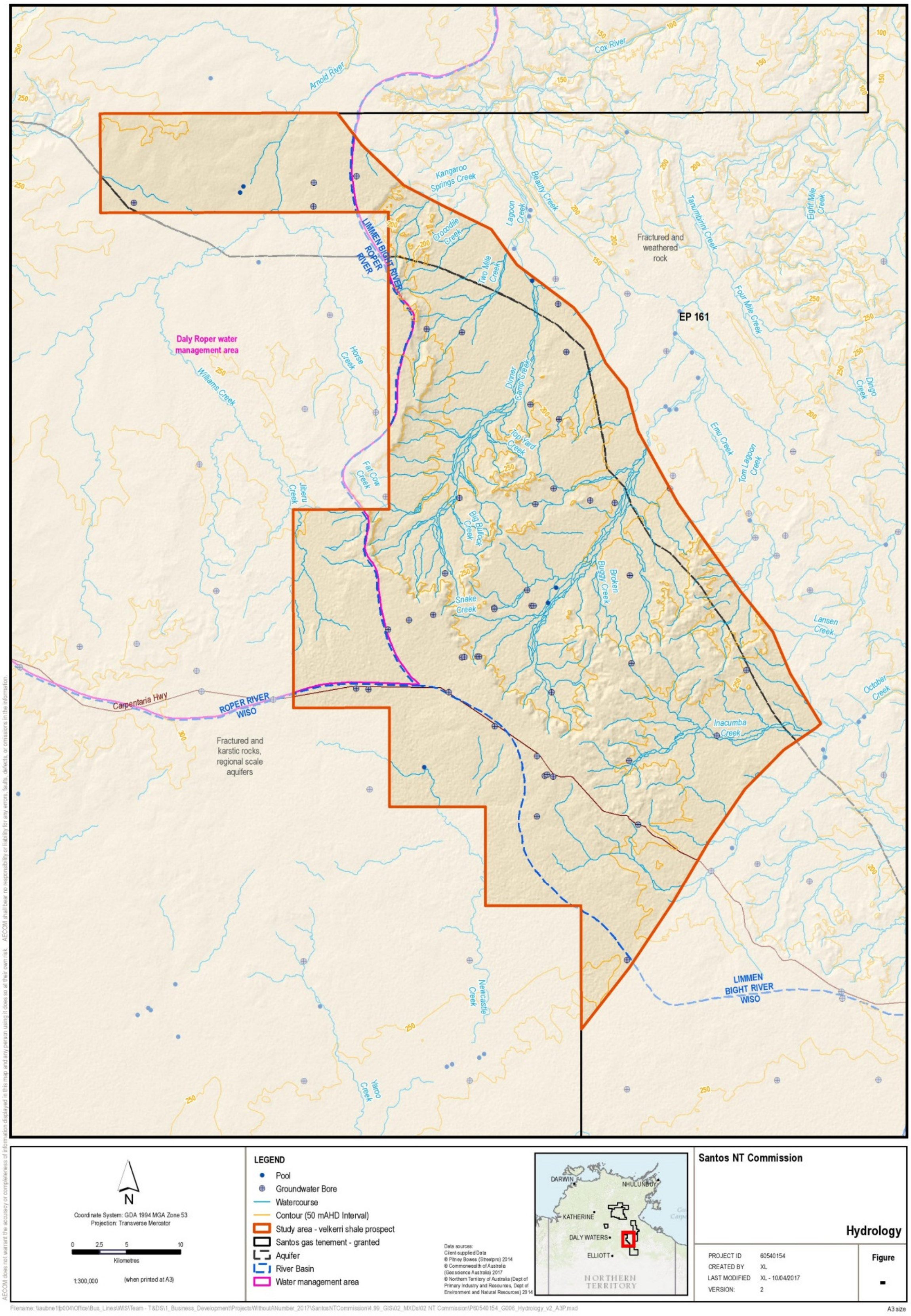
Groundwater resources used within the Beetaloo Basin are of good quality, with average electrical conductivity (EC) within the acceptable limit for potable water (1,875 µS/cm). The freshest groundwater is associated with the fracture rock aquifers, possible due to rapid regular (seasonal) recharge with shorted flow paths.

The limestone and dolomite (Cambrian Limestone Aquifer) aquifers have high proportions of Ca-Mg-HCO_3 and thus increased EC concentrations.

The formation water is hyper-saline and considered connate water, sourced from depths of 780 to 1,350 m below surface. The groundwater EC range from 31,800 µS/cm (Hayfield Mudstone) through to 159,000 µS/cm (Moroak Sandstone).

A figure showing the location of known groundwater bores in the area is provided in Figure 31.

Figure 31 Hydrology of the Study Area, including known groundwater bores



Data sources:
Client supplied Data
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© Northern Territory of Australia (Dept of Primary Industry and Resources, Dept of Environment and Natural Resources) 2014

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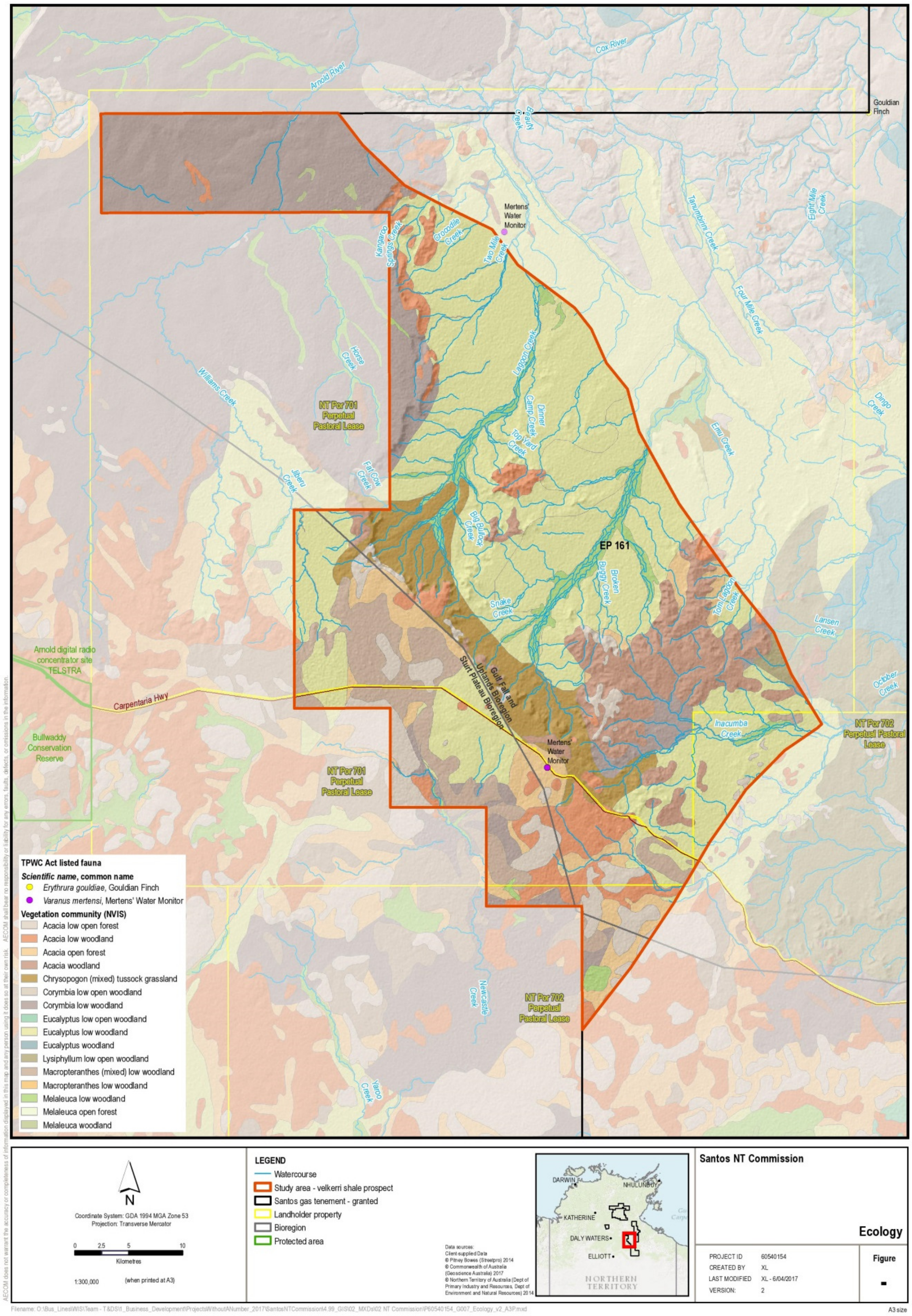
5.3 Ecological values

This section describes the ecology resources relevant to the target area within EP161 as illustrated in Figure 32. Terrestrial ecology is covered under land-related risk themes and aquatic ecology is covered under water-related risk themes discussed in Appendix A (Risk themes mitigation matrix).

Figure 32 EP161 target area ecological values



5.3.1 Bioregions

EP161 overlies the Sturt Plateau and the Gulf Falls and Uplands bioregions as shown in Figure 32 and introduced in the following sections.

Stuart Plateau bioregion

The Sturt Plateau bioregion dominates most of the southern part of EP161, south of the Carpentaria Highway. It mostly comprises a gently undulating plain on lateritised Cretaceous sandstones. Soils are predominantly neutral sandy red and yellow earths. The most extensive vegetation is eucalypt woodland (dominated by Variable-barked Bloodwood Corymbia dichromophloia) with spinifex understorey, but there are also large areas of Lancewood (Acacia shirleyi) thickets, Bullwaddy (*Macropteranthes keckwickii*) woodlands, Acacia shrub lands on deep sands, and eucalypt open forests (dominated by a range of species including Darwin Stringybark Eucalyptus tetrodonta) over tussock grass understorey (Santos, 2016).

The Sturt Plateau bioregion includes the most extensive areas of the distinctive lancewood-bullwaddy vegetation associations, with associated fauna including the Spectacled Hare-wallaby (Santos, 2016).

Most of the bioregion is generally in moderate to good condition, due at least in part to the lack of intensive development. There are pervasive, but generally minor impacts associated with weeds, feral animals, pastoralism and changed fire regimes. Notwithstanding the recent establishment of a conservation reserve selected to include lancewood-bullwaddy associations, the existing reserve system is meagre and does not include representation of the range of environments within the bioregion (Santos, 2016).

Extension of the reserve system and enhancement of integrated management of weeds, feral animals, and fire has been identified as management priorities for the bioregion. The bioregion is targeted for intensification of development, including subdivision of existing pastoral properties, horticultural development, and more widespread planting of exotic pasture grasses (Santos, 2016).

Gulf Falls and Uplands Bioregion

The Gulf Falls and Uplands bioregion occurs in the northern half of EP161, north of the Carpentaria Highway, and on the southern boundary of the EP. It comprises undulating terrain with scattered low, steep hills on Proterozoic and Palaeozoic sedimentary rocks, often overlain by lateritised Tertiary material. Soils are mostly skeletal or shallow sands. The most extensive vegetation is woodland dominated by Darwin Stringybark Eucalyptus tetrodonta and Variable-barked Bloodwood C. dichromophloia with spinifex understorey, and woodland dominated by Northern Box Eucalyptus tectifica with tussock grass understorey (Santos, 2016).

The ranges of this bioregion have some significant refugial values, and include some endemic or near-endemic species and many geographically disjunct occurrences. The bioregion is generally in good condition, but this is being eroded by continuing increases in the number of feral animals (especially pigs, buffalo, donkeys and cattle) and weeds, and broad-scale changes in fire regime (Santos, 2016).

5.3.2 Flora

Vegetation types within EP161 include woodland, open woodland, open forest, tussock grassland and hummock grasslands (Santos, 2016).

The dominant species within the vegetation communities present include Darwin Stringybark *Eucalyptus tetrodonta* and Variable-barked Bloodwood *C. dichromophloia* with spinifex understorey, and woodland dominated by Kullingal *Eucalyptus pruinosa* or *Melaleuca* spp. with tussock grass understorey. There are also large areas of Lancewood (*Acacia shirleyi*) thickets, Bullwaddy (*Macropteranthes keckwickii*) woodlands and Acacia shrublands on deep sands (Santos, 2016).These vegetation communities are mapped in Figure 32.

5.3.3 Fauna

The region supports a diverse range of fauna. Over 435 vertebrate species have been recorded from the Gulf Falls and Uplands bioregion, including 24 species that are rare or threatened. Ten species in this bioregion are listed as threatened at a Territory or national level. The Sturt Plateau bioregion is known to support over 350 vertebrate species, including six species listed as threatened at a Territory or national level (Santos, 2016).

The sandstone ranges and stony hills of the region support a number of endemic species, while the major river systems are important environments for many species because of the much lower annual rainfall than the more northern savannas, and the very high summer temperatures (Santos, 2016).

The region's eucalypt woodlands support a relatively diverse range of birds, with nectarivorous species such as honeyeaters, friarbirds and lorikeets extremely abundant when the dominant trees flower. The diversity and abundance of small mammal species in the region's woodlands are low compared with higher rainfall woodland to the north, possibly because of limited availability of daytime refuges among small trees (Santos, 2016).

5.3.4 Protected or conservation areas

The Limmen National Park overlaps the northern section of EP161 while a separate section of the park lies to the east of and outside the EP161 boundary. No exploration, appraisal or production activities are currently proposed within either section of the National Park. The Bullwaddy Conservation Area is west of and outside the EP161 permit area. No sites identified as of conservation significance for biodiversity values in the NT occur within EP161.

5.3.5 Threatened flora and fauna

Interrogation of databases and a review of published material indicate that a number of rare or threatened species have been recorded within the region. A search of online databases for flora and fauna species listed under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act) and a review of NT flora and fauna databases was undertaken on 31 March 2017 to identify nationally listed threatened flora or fauna that may occur or are likely to occur within EP-161. The search identified 12 Nationally Threatened species, 11 Listed Migratory Species, and 16 Listed Marine Species as potentially occurring within the study area. The search did not identify any Threatened Ecological Communities in the area (DOEE, 2017).

Due to the small nature and scale of the disturbance footprint associated with the development scenario and the flexibility of location selection, no threatened species or species habitat are considered likely to be significantly impacted. This would however need to be assessed once planning has progressed.

5.3.6 Significant habitat

No sites of conservation significance for biodiversity values have been formally identified within the project area. Habitats of particular significance in the region include riparian and wetland systems, particularly deep gorges with deep permanent water (which provide important refuges), and sandstone ridges, stony hills and rocky ranges, which have also been identified as a significant biological refuge. Large trees with hollows provide important habitat for a range of species, including a number of threatened species (Santos, 2013).

5.4 Land Rights, Native Title and Sacred Sites

EP 161 is located on land subject to native title and on that basis, Santos has an executed Co-operation and Exploration Agreement with the Native Title parties and the Northern Land Council. This agreement provides an agreed process for the lifecycle of exploration activities in EP 161 including traditional owner engagement, site clearances (sacred site) environmental compliance, employment and training opportunities and compensation based on a percentage of program cost. The agreement also has provision for a production agreement to be negotiated which ensures traditional owners are compensated for the lifecycle of petroleum activity.

The agreement prescribes the requirements for work programs to be submitted on an annual basis to ensure traditional owners are consulted and informed of all activities. This generally involves meetings and community consultations 'on country' and also ensures traditional owners are involved in the process to undertake sacred site clearances to obtain certification.

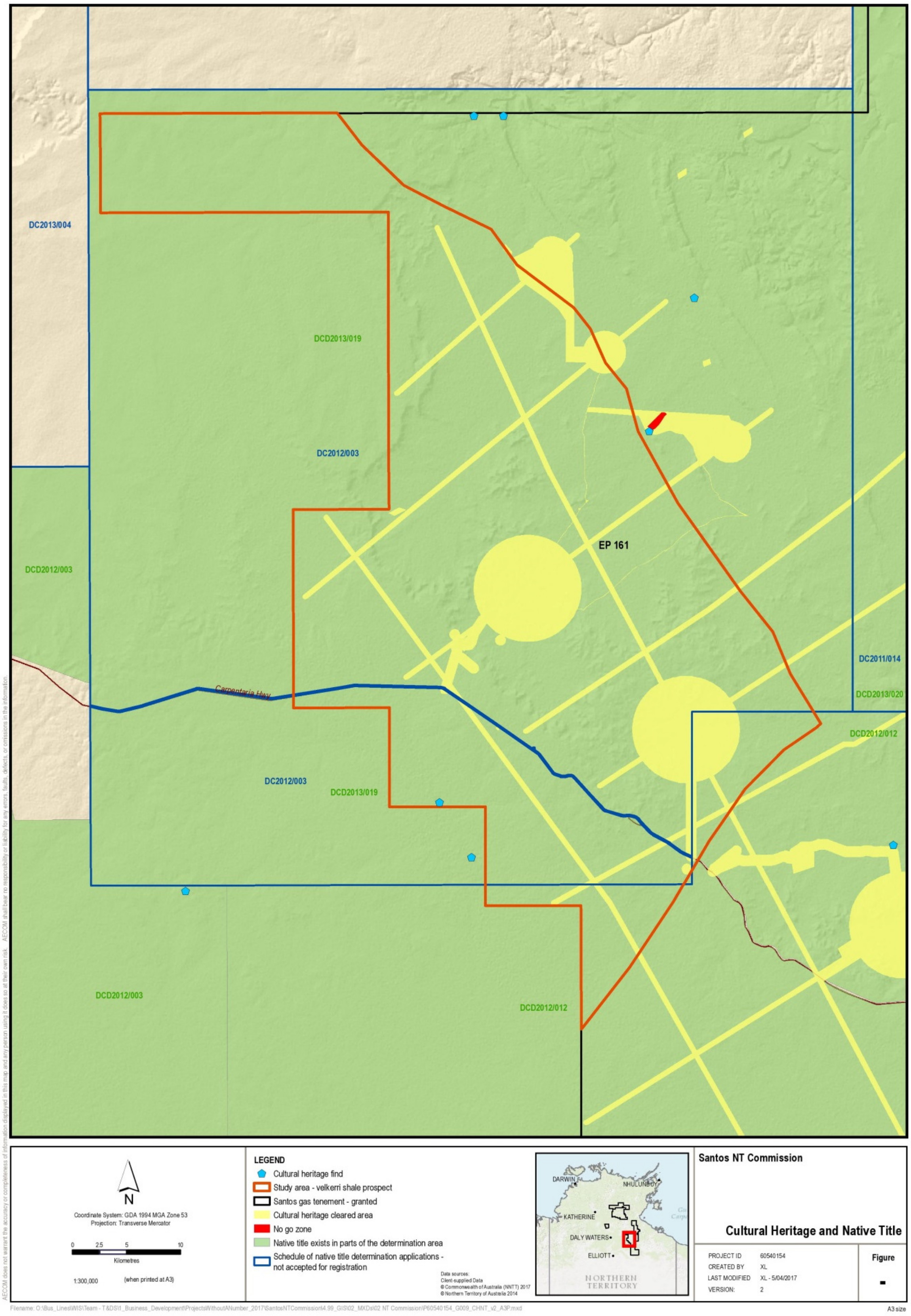
All Santos activities to date across EP161 have been subject to sacred site certification through the Aboriginal Areas Protection Authority in accordance with the Sacred Sites Act 1989.

Any new activity that is located outside of an area subject to clearance and certification will be subject to a new work program in consultation with the Northern Land Council and traditional owners.

The values of land rights and sacred sites are considered in Appendix A (Risk themes mitigation summary).

As part of planning exploration, and future appraisal and production activities, these sites will be avoided with positioning of well sites, camp sites and access tracks based on the conditions of the sacred site certifications. Santos works closely with the Northern Land Council, Traditional Owners and Aboriginal Areas Protection Authority in the identification and protection of sacred sites. Figure 33 presents the cultural heritage values of the target area.

Figure 33 EP161 target area cultural heritage values



6.0 Regulatory context

The following sections describe the current and emerging regulatory context relevant to hydraulic fracturing assessment and approvals, including:

- Commonwealth legislation, assessment and approvals (Section 6.1)
- Northern Territory legislation, assessment and approvals (Section 6.2)

Whether conventional or unconventional gas resources are being targeted, proposed construction, operation and decommissioning processes are assessed in Australian states and territories and abroad under relatively similar regulatory frameworks and assessment and approval models that offer confidence and assurance to the regulator, community and business.

6.1 Commonwealth

Operators are responsible for determining if a self-referral to the Commonwealth Government for assessment is required under the *Environment Protection and Biodiversity Protection Act* (EPBC Act).

The EPBC Act provides a legal framework to protect and manage impacts upon matters of national environmental significance, which include listed threatened species and communities, listed migratory species, wetlands of international importance, nuclear actions, Commonwealth marine areas, World Heritage properties and National Heritage places.

Matters of national environmental significance also include water resources in relation to coal seam gas and large coal mining development. The Commonwealth Government established the Independent Expert Scientific Committee on Coal Seam Gas and Large Coal Mining Development (IESC) as a statutory body under the EPBC Act. The IESC provides advice to Commonwealth and state government regulators on water-related impacts of coal seam gas and large coal mining development proposals. These arrangements are supported by a National Partnership Agreement on Coal Seam Gas and Large Coal Mining Development, a joint initiative of the Commonwealth Government and participating states (New South Wales, Victoria, Queensland and South Australia) (Santos, 2017).

In 2013, the Council of Australian Governments' (COAG) Standing Council on Energy and Resources (SCER) published a national harmonised regulatory framework for coal seam gas to address concerns based on four key areas: water management and monitoring; well integrity and aquifer protection; hydraulic fracturing; and, chemical use (Santos, 2017). The COAG Energy Council (previously SCER) continues to monitor implementation of the framework across participating states and territories.

In December 2013, the Council of Australian Governments (COAG) recommitted to reform environmental assessment and approvals systems. Accordingly, the Australian Government committed to delivering a 'one-stop-shop' for environmental approvals that will accredit State/Territory regulatory systems under national environmental law to create a single environmental assessment and approval process (Hawke, 2015).

6.2 Northern Territory

The NT Government supports the responsible development of an onshore oil and gas industry that has the potential to provide significant, long term economic benefits for Territorians (DPIR, 2016), including employment opportunities, regional economic and infrastructure development and future royalties.

6.2.1 Petroleum tenure

The *Petroleum Act 2016* (Petroleum Act) and the *Schedule of Onshore Petroleum Exploration and Production Requirements 2016* are the principal legislation addressing petroleum tenure, exploration and production activity in the NT. The Petroleum Act is the legal framework that ensures companies undertake effective exploration for petroleum and any benefits of petroleum production and development is returned to the NT.

Operators secure land tenure through an Exploration Permit (EP). In applying for a permit, operators outline a five year work program, taking into account relevant information such as environmental protection, heritage and cultural issues, which could add requirements or conditions onto the permit.

If an operator’s application meets the requirements and is approved, an EP is issued, which gives the holder exclusive right to explore for hydrocarbons and undertake activities such as seismic surveys and drilling and completions within the permit area in accordance with the Act, the Schedule and the permit conditions (Hawke, 2014).

Santos currently holds exploration permits EP161, EP162 and EP189 in Beetaloo Basin, with EP288(A) and EP299(A) currently under application – refer Section 4.1.

6.2.2 Land access

Consultation and negotiation with third parties who have a recognised interest in or ownership of the land included in the permit area must be undertaken and their permission to access the land for exploration secured. This includes following the legislated processes associated with obtaining access with pastoralists under the Petroleum Act and traditional owners under the Land Rights and Native Title Act.

Santos has fully executed Co-Operation and Exploration agreements in place with the relevant land councils i.e. Northern Land Council (Northern Land Council) for McArthur permits EP161, EP162 and EP189. Santos has 29 executed land access agreements in place across its NT permits.

6.2.3 Exploration

Through the exploration phase (detailed in Section 3.2.1), the explorer progressively builds on the understanding of the resource and surrounding conditions in order to make informed decisions about whether there is a gas reserve suitable for production. Depending on the results of the exploration wells, the explorer may decide to drill and to undertake hydraulic fracturing tests on the well. Based on the information gained through exploration, the explorer will decide whether production is viable and determine the land area required for production purposes (Hawke, 2014).

6.2.4 Securing a production licence and operational phase

If the operator has defined an oil or gas resource and plan to move forward to production they need to apply for a Production Licence (PL), which will typically be over an area smaller than the initial EP. The PL provides exclusive access to the land for the purpose of production.

Typically an application for a PL will include all of the following:

- Survey program including the area of the seismic survey
- Environmental management plan (EMP) including measures that will be put in place to protect the environment (including rehabilitation and conservation planning) in the location of the seismic survey and EMP summary
- Safety management plan
- Insurance certificate(s)
- Emergency response plan
- Oil spill contingency plan
- Environment rehabilitation security calculation form
- Stakeholder consultation log
- Cultural/sacred site clearances
- Land access agreements/notice of entry.

Unless addressed within the EMP, 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.

Operational approvals are required for regulated activities including seismic surveys, any drilling, side tracking a well, well suspension, well abandonment, well completion, flow testing and hydraulic fracture stimulation. Each operational approval requires a separate EMP (Hawke, 2014).

6.2.5 Drilling and well construction

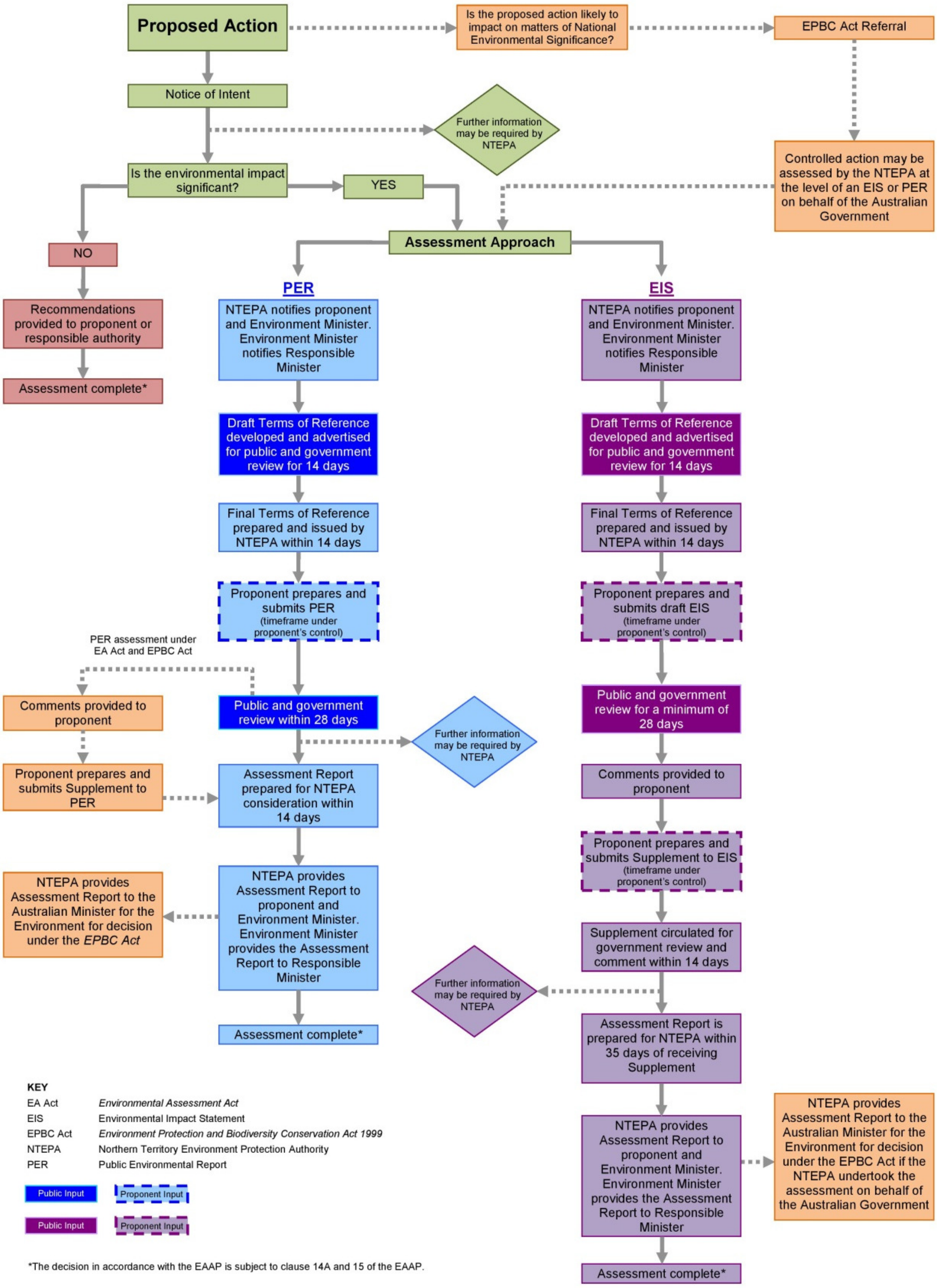
In the NT, well design and well integrity are addressed in Clauses 501-532 of the Schedule of Onshore Petroleum Exploration and Production Requirements (2012) under the Petroleum Act. A work program is submitted as part of the project assessment process, which includes details relating to well design, construction and integrity. Internal DPIR checklists ensure that the operator has addressed critical operational and well safety issues including:

- Activities and material meet or exceed API standards
- Blow out preventer (BOP) systems
- Cementing of all casing strings to surface
- Mandatory water quality testing, before during and after the activity
- Mandatory validation of casing and cement using Cement Bond Logs (CBL)
- Mandatory validation of all barriers by pressure testing
- Mandatory Formation Integrity Testing (FIT)
- Pressure monitoring provides confirmation that well integrity has not been impacted by fracture stimulation activities, and
- Installation of a Completion Tubing string.

Environmental impact assessment

The NT Environment Protection Authority (NT EPA) is responsible for administering the *Environmental Assessment Act* (EA Act) and the subordinate Environmental Assessment Administrative Procedures (EAAP), the key legislation used to perform the Environmental Impact Assessment (EIA) of proposed actions in the NT (NT EPA, 2017).Section 7 (2) of the EA Act authorises the NT EPA to request the preparation of an environmental impact statement. Figure 34 illustrates the process of environmental impact assessment in the NT.

Figure 34 Northern Territory EIA Process. Source: NT EPA



Water management

The NT has declared Water Control Districts where there is a need for enhanced management for the sustainability of groundwater reserves and river flow, pertaining to the groundwater bores drilled within the district, water allocation plans and water extraction licences where required (declared under section 22 of the *Water Act, 2016* (Water Act)). The values of surface and groundwater within the NT are described in seven categories, namely agriculture; aquaculture; public water supply; environment; cultural; industry; rural stock and domestic. Each beneficial use has water quality guidelines based on scientific evidence or judgement to help protect, maintain and achieve a high water quality for the long term.

In the NT when water is used for extracting petroleum resources (such as shale gas) it is not subject to regulation under the Water Act.

6.2.6 Hydraulic fracturing

Hydraulic fracturing is an activity regulated by the NT Department of Primary Industry and Resources (DPIR). The *Petroleum (Environment) Regulations* form part of a regulatory framework for the onshore oil and gas industry that requires environmental risks and impacts of an oil and gas activity to be identified and reduced to an acceptable level i.e. as low as reasonably practical (ALARP).

The Regulations achieve these objectives by requiring operators to submit an EMP to the Minister and relevant Land Council(s) for approval before undertaking a ‘regulated activity’. The requirements of an EMP are detailed in Schedule 1 (Information to be included in environment management plan) of the Regulations. Approved EMPs are made public and are legally binding documents meaning that companies must comply with their approved plans.

The EMP must provide a description of the proposed activities, description of the existing environment, assessment of environmental impacts and environmental risks, environmental outcomes and environmental performance standards, details of systems, monitoring and testing. The plan also details water management; type and quantities of chemicals used in the hydraulic fracturing; well integrity; communication and reporting. Chemical disclosure statements and summaries of EMPs are available on the government’s website.

Stakeholder engagement (including landholders and traditional owners) in relation to the regulated activity forms part of the EMP. Stakeholders must be given information about *Petroleum (Environment) Regulations*:

a. give each stakeholder information about:
   i. (the regulated activity the interest holder proposes to carry out; and
   ii. the location (or locations) where it is proposed to carry out the activity; and
   iii. the anticipated environmental impacts and environmental risks of the activity; and
   iv. the proposed environmental outcomes in relation to the activity; and
   v. the possible consequences of carrying out the activity to the stakeholder's rights or activities; and
b. allow a reasonable period for the stakeholder to respond to the information given by the interest holder.

The approval criteria of an EMP must include all applicable and appropriate information required by the regulation in relation to the activity including sacred site certification, evidence traditional owners have been consulted and the execution of a land access agreement and demonstrate that the activity is carried out in a manner environmental impacts and environmental risks of the activity will be reduced to a level that is as low as reasonably practicable and acceptable. The Minister must also take into account the principles of ecologically sustainable development when considering approval of an EMP or previous environmental report recommendations in relation to the regulated activity.

The process from securing land for exploration until the operational phase, and the permits and/or approvals to be obtained will be discussed below.

Management and monitoring

The key environmental document in the NT approval process is the EMP, which clarifies the regulatory expectations for environmental management of petroleum activities in NT. The *Petroleum (Environment) Regulations* (the Regulations) require an EMP, which, once approved, is a statutory document that is enforceable. Approval of an EMP is necessary for all activities that have an environmental impact or risk but is only one of several approvals required for the activity to proceed. When an EMP is written, it requires the operator to detail what it is going to do, the environmental risks associated with what it is going to do and how those risks will be managed. If Santos was planning to undertake hydraulic stimulation (in the absence of a moratorium), it would need to submit an EMP which details the proposed hydraulic fracture, the relevant risks associated with that activity and how they would be monitored and managed. Once an EMP is approved, the program of works cannot be varied without approval. EMP's are made publically available by the NT Government at - https://dpir.nt.gov.au/mining-and-energy/public-environmental-reports/reports-for-petroleum-operational-activities

Recommendations from Hawke Reform reports

The NT *Inquiry into Hydraulic Fracturing and the Potential Impacts on the Environment* (Hawke, 2014) recommended that the *NT Environment Assessment Act* (and by extension, its implementation) be reviewed in concert with creating a robust regulatory system for hydraulic fracturing. Recommendations from the report include:

- Align the petroleum and mineral royalty frameworks
- Restructure the *NT Environmental Assessment Act* in light of the reform report and the proposed bilateral agreements with the Commonwealth on environmental assessments and approvals
- Form a Cabinet Sub-Committee, chaired by the Deputy Chief Minister and comprising the Ministers whose portfolios cover Lands, Planning and Environment; Land Resource Management; Mines and Energy; and Primary Industry and Fisheries to oversee the work required for the NT to set the standard for a best practice regulatory regime
- There is no justification for the imposition of a moratorium of hydraulic fracturing in the NT
- Environmental risks associated with hydraulic fracturing can be managed effectively subject to the creation of a robust regulatory regime (Hawke, 2014).