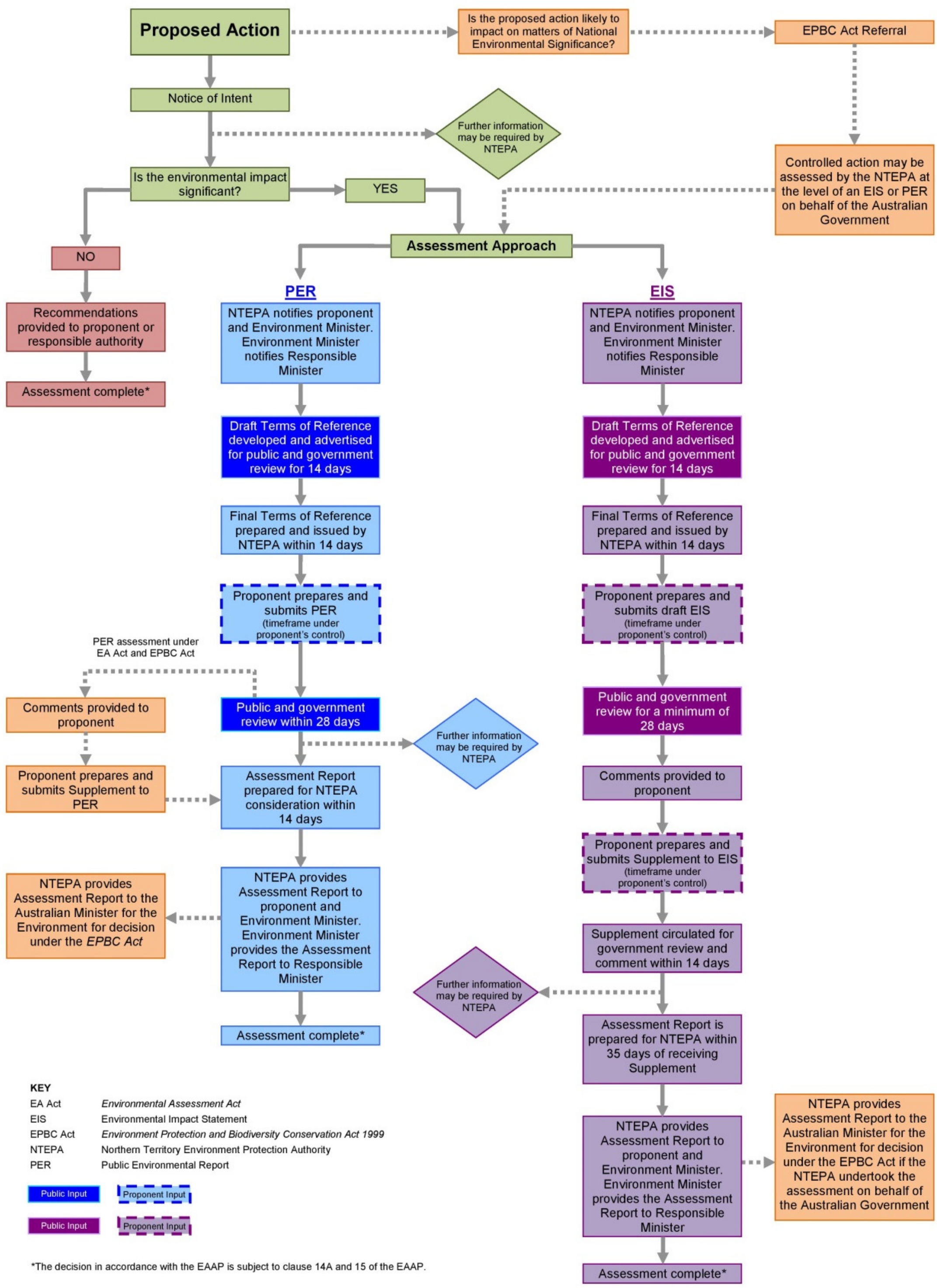
Figure 34 Northern Territory EIA Process. Source: NT EPA



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

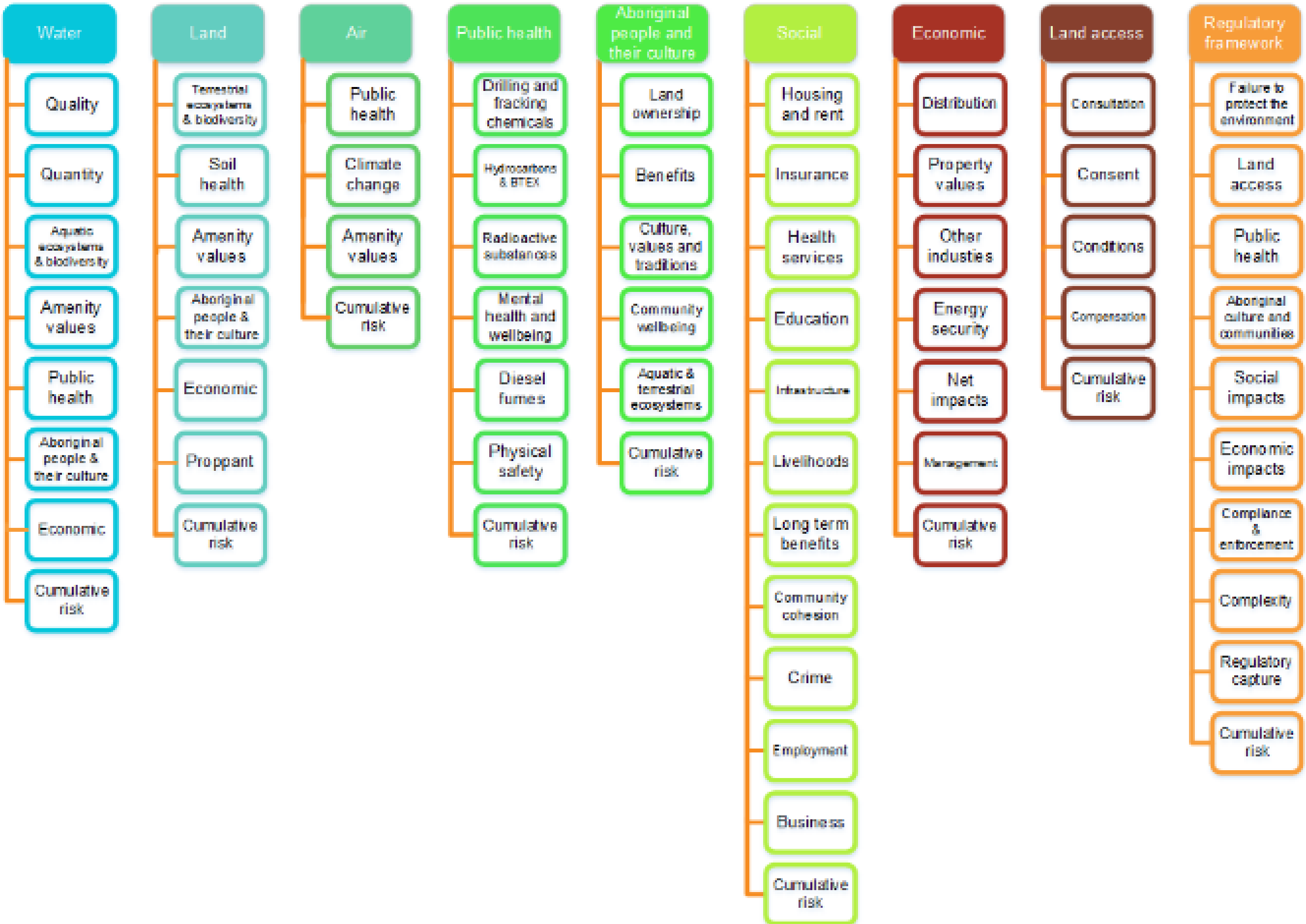
The NT *Inquiry into Hydraulic Fracturing and the Potential Impacts on the Environment* (Hawke, 2014) recommended that the *NT Environment Assessment Act* (and by extension, its implementation) be reviewed in concert with creating a robust regulatory system for hydraulic fracturing. Recommendations from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

7.0 Hydraulic fracturing risk themes and focus areas

This submission recognises the risk themes (Figure 35) that are understood to be of high priority and greatest concern for the NT Government, traditional owners, landholders, local communities and businesses. Each risk theme is examined and appropriate mitigation identified with supporting evidence in Appendix A.

Figure 35 Risk themes



Source: (NT Government, 2016)

In this section, Santos presents a more focussed and practical discussion of certain activities or potential impacts that are attributed to hydraulic fracturing and recognised as areas of concern to the Inquiry; each of these discussions will deal with any number of the risk themes identified by the panel in a practical way. Each discussion builds a scientific basis that draws on available domestic and international evidence to justify the realities of the potential risk and demonstrate the effectiveness of Santos and industry mitigation to reduce risks to an acceptable level or as low as reasonably practical.

The identified focus areas discussed in this section include:

- Well integrity
- Fracture growth
- Induced seismicity
- Water supply and containment
- Wastewater and waste management
- Hydraulic stimulation chemicals

- Fugitive emissions
- Construction noise, diesel emissions and dust
- Land access and compensation
- Economics.

7.1 Well integrity

Well integrity describes a well's ability to isolate fluids within the well from the surface and sub-surface zones exterior to the well during its working life and beyond, including after it has been formally abandoned by the mandated well abandonment processes.

To inform the assessment of risks associated with mechanical integrity of wells during hydraulic fracturing within a shale gas production area, well design, engineering and construction must be understood – refer to Section 3.2.2.

7.1.1 Activity

Robust well design, engineering, construction and eventual abandonment ensures that well integrity is maintained at all times, including during the application of high pressures for multiple hydraulic fracture stimulation events.

Well failure can occur due to incorrect well construction, incorrectly sealed wells, or through deterioration due to pressure, stresses and corrosion. If the cement or casing around the well fails then contaminants can migrate through them and cause groundwater pollution to overlying aquifers (US EPA, 2012).

Inadequate construction, operation or decommissioning can severely impact on a well's integrity and eventually, cause well failure. Without sufficient management controls in place, potential issues may include:

- Migration of stimulation fluids or natural gas to surrounding geological formations or aquifers
- Uncontrolled pressurised stimulation fluid release at surface
- Migration of groundwater including mixing of groundwater sources
- Migration and uncontrolled release of natural gas at surface.

7.1.2 Scientific evidence

Well integrity ensures that fluids produced by onshore gas wells (gas/water from underground geological formations) are contained in such a way as to protect the environment and assure the safe flow of gas to the surface (GasFields Commission Queensland, 2015).

International experience demonstrated that well integrity failures are rare; for example, data from 253,090 wells in Texas found that only 4 in every 100,000 (0.004%) wells constructed to modern standards experienced a loss of well integrity, compared to 0.2% for older wells (King & King, 2013).

In regards to other Australian experience (GasFields Commission Queensland, 2015), there have been 21 statutory notifications (a rate of 0.3%) under the well construction code concerning suspect downhole cement quality during construction. For all 21 notifications in Australia, the gas

There are detailed codes and standards for design, construction and testing. Santos would be supportive of legislative or regulatory amendment to adopt a best practice code in the NT.

Well design, materials selection and construction is highly engineered and controlled, using specialist materials and equipment – above and beyond design specifications, materials used and verification testing performed by other industries that drill through aquifers and aquitards such as water bores.

Materials and construction are subject to multiple verification testing events. Well performance is verified prior to hydraulic fracturing, and well integrity is monitored during stimulation.

companies followed up with subsequent testing to assess well integrity and determine any remedial work. The Petroleum and Gas Inspectorate followed-up on all 21 notifications to ensure that the tests, and any required remediation work, conducted on the well was successful before gas production commenced. In all cases the ongoing monitoring programs were put in place to ensure ongoing integrity of the well.

In relation to these notification examples:

- The ultimate cementing 'failure' rate after testing, remediation, and follow-up according to the Code stands at 0%.
- The likelihood and therefore risk of a subsurface breach of well integrity is assessed to be very low to near zero.

Given national and international experience, the potential for an "issue" to occur over a well's operating life is considered possible. The risk of migration of fluids (gas or water flow) between formations and / or to surface is managed through the lifecycle management of well integrity. This includes the wells' initial design (codes / standards), materials sections, installation, verification and performance monitoring and ultimately decommissioning.

Based on Santos' experience within Australia applying such national and international guidance and implementing a well management integrity system, the risk of migration of fluids (gas/water) between formations and/or to surface is considered low.

An August 2011 report from the USA's Groundwater Protection Council examined more than 34,000 wells drilled and completed in Ohio between 1983 and 2007, and more than 187,000 wells drilled and completed in Texas between 1993 and 2008. It found only 12 incidents in Ohio that related to failures of (or graduate erosions to) casing or cement – a 0.03% failure rate. In Texas, the failure rate was only about 0.01%. Based on Pennsylvania Department of Environmental Protection data compiled by the American Petroleum Institute, only about 0.33% of all oil and gas wells drilled in Pennsylvania since 2005 have failed (APPEA, n.d.).

In Alberta (Canada), Watson and Bachu (2009) used data from 315,000 oil, gas and injection wells to assess gas leakage pathways. They found gas migration leakage in 0.6% of wells and surface-casing vent-flow in 3.9% of wells, and reported that exposed (uncemented) casing was the main factor in the occurrence of leakage and casing failure. Some leaky wells had only a single casing or were left uncased below the surface aquifer, had not been cemented or cementation had not reached required depth. They concluded that leakage was mostly due to mechanical factors controlled during wellbore drilling, construction and abandonment, mainly cementing (Hawke, 2014).

For North America, ALL Consulting (2012) list many of the most prominently reported oil and gas well related incidents of ground water contamination between 2001 and 2012. Many of these cases involved leaks from old abandoned wells, leaks associated with poorly constructed, sealed or cemented wells, or surface spills or improper release of chemicals and waste water, but in none of these listed cases was hydraulic fracturing itself unequivocally determined to be the pathway for ground water contamination (Hawke, 2014). Groat and Grimshaw (2012) also analysed numerous reported environmental incidents associated with oil and gas development concluding that there was little or no evidence of ground water contamination resulting directly from hydraulic fracturing (Hawke, 2014).

A few studies have attempted to estimate failure or leakage rates from data across a large number of wells. In US, Kell (2011) examined ground water incident investigations in Texas (between 1993 and 2008) and Ohio (1983-2007). Most of the 396 reported incidents were related to construction and maintenance of reserve pits, waste management and disposal, or orphaned wells, and a large proportion of incidents occurred early in the study periods. In Ohio, where over 33,000 wells were drilled in the study period, 12 had incidents related to well construction deficiencies, and six of these wells had the surface casing sealed with clay rather than cement. In Texas (187,888 wells) only two incidents were attributable to deficient well construction practices, including one caused by a short surface casing that did not adequately isolate the basal section of the useable ground water aquifer. During the study period for Texas, over 16,000 horizontal shale gas wells with multi-stage hydraulic fracturing were completed. No ground water contamination incidents were reported from any of the drilling, construction, fracturing or production operations of these horizontal gas wells (Hawke, 2014).

When effectively regulated and executed, a properly constructed well is the key to addressing most of the subsurface environmental concerns raised by the community.

In the Cooper Basin (SA), Santos has more than 50 years of drilling experience, and almost 50 years of hydraulic fracturing experience. Although the formations targeted in the Cooper Basin are generally different (sandstone instead of shale), the drilling and hydraulic fracturing principles remain consistent. The tight sandstones of the Cooper Basin are analogous from a well design standpoint to the NT shales due to:

- Similar formation depths and separation from aquifers
- Similar formation permeability is low requiring hydraulic fracture stimulation to produce
- Multiple fracture stages required per well
- Similar requirements for casing and cement design (drilling, fracturing and production load cases).

As such, the Cooper Basin provides a good analogy to provide community, stakeholder and regulator confidence in the principles and practices implemented by Santos in over 50 years of operatorship.

Properly undertaken, with careful site characterisation included as part of the well and fracture design, hydraulic fracturing is unlikely to create connections between previously unconnected aquifers as tools and monitoring processes are available to sufficiently manage the risks (IESC, 2014).

7.1.3 Santos and industry mitigation

Santos defines a well barrier to be a containment device designed to prevent the flow of formation fluid into overlying aquifers or to surface. During well construction, multiple barriers are installed to provide redundancy should one fail. A well failure is defined as a complete loss of well barriers resulting in the potential for migration of gas or fluid or a loss of surface barriers resulting in an uncontrolled release of wellbore fluid/gas at surface.

Santos adheres to the Santos Well Integrity Procedure (WIP), which governs the integrity level for each well in the Cooper Basin, and would be applied to the wells in the NT. The well integrity level assessment is used to define the integrity management plan required for each well.

Figure 36 lists the well integrity level rating associated with the condition of the wellbore barriers. If a well has a well integrity level of 1 or 2, a generic integrity management plan (IMP) is used to manage risk. If a well has a well integrity risk of 3 or above, a well specific IMP is required. Well specific IMPs are completed during the risk assessment process and contain additional controls over and above those specified in the generic IMP. These risk assessments are reviewed periodically commensurate with risk, and management plans are updated as a minimum of once every five years, or as triggered by inspection or monitoring data.

Note - Surface casing is not considered a barrier for well integrity in the table below. However, in wells constructed from 2000 onwards, it provides an additional barrier for shallow aquifers.

Figure 36 Well integrity risk level ratings.

Well Integrity Level	Condition of Barrier(s)
1	As new with all required barriers tested and verified to be in place.
2	Evidence of some degradation of any or both barriers.
3	Primary or secondary barrier failed. Remaining barrier intact.
4	Primary or secondary barrier failed. Remaining barrier suspect, i.e. condition deteriorated or suspect that its integrity is being compromised.
5	Both primary and secondary barriers failed or unable to hold the required pressure. Condition intolerable.

To date, Santos has drilled approximately 2,736 wells in the Cooper/Eromanga Basin (2,276 of which are active and 460 are decommissioned). Through the effective implementation of a well integrity management plan, there are currently no high risk wells (level 4 or level 5 risk). This means that the well integrity management plan (design, procurement, construction, verification and operational monitoring and remedial actions) has successfully ensured that at least one barrier is in place to prevent unwanted gas or fluid migration.

Over the 60 year history of the Cooper/Eromanga Basin, 11 of the 2736 wells (0.4%) have been assigned a Level 4 integrity rating at some stage over their life: meaning that at that time there is one barrier remaining in the well, that is the surface casing or wellbore fluid with a higher hydrostatic pressure than that of the formation. All of these wells have been decommissioned or remediated to restore well bore barriers to allow continued production in accordance with well integrity management plan procedures.

Over the 60 year history of the Cooper/Eromanga Basin, only two of the 2736 wells (0.07%) have been assigned a Level 5 integrity rating at some stage over their life, meaning that at that time there were no barriers remaining in place to manage the risk of unwanted gas or fluid migration. For one of these wells the barrier failure was at surface (i.e. downhole barriers remained in place). Both of these wells were either remediated or decommissioned.

Since 1992 well design specifications, cementing practices and an improved well integrity monitoring program were introduced. As a result, only one well out of the 1,727 wells (0.06%) drilled during this period reached a Level 4 rating. This well was identified and remediated in accordance with the well integrity management plan and at all times the risk of unwanted gas or fluid migration was managed. During this same period, zero wells out of the 1,727 wells (0%) drilled have reached a Level 5 rating.

In summary, since 1992, the improved well design standards and cementing practices has reduced the risk of barrier issues and failures. Under both designs however, an effective well management system which includes operational testing and monitoring, identified and managed risks through the implementation if remedial actions.

Santos and industry mitigation actions are widely accepted and implemented to ensure well integrity, including:

- Codes of practice and industry best practice
- Well design, materials selection and construction
- Well integrity management and monitoring
- Well decommissioning and abandonment.

Codes of practice and industry best practice

The principle of well integrity is to ensure compliance to high design standards, robust safety obligations and industry best practice for monitoring and maintenance that will preserve the well and its equipment in a suitable condition for a well's useful life. Well integrity management systems for subsurface assets aim to ensure the wells meet operational availability and well integrity goals.

To ensure the well design and construction meets international best practice policies and procedures are developed by Santos to meet or exceed the regulatory framework and industry standards such as those specified by the American Petroleum Institute (API).

The most cited industry guidelines for shale gas well construction and integrity are from the API, notably the *Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines* (API, 2009) and associated standards, and most major shale and coal seam gas proponents operating in Australia state that they adopt (or exceed) these as the minimum standard. Various industry documents and the submission from the Australian Petroleum Production and Exploration Association (APPEA) also refer to the APPEA Code of Practice for Hydraulic Fracturing.

Wells should be constructed and decommissioned based on international standards such as the API standards or guidelines such as the *Queensland Code of practice for constructing and abandoning petroleum wells* (DEEDI, 2011), (Australian Petroleum Institute (API), 2002), (API, 2009) and the NSW *Draft code of practice for coal seam gas exploration* (NSW Government, 2012), both of which have set minimum standards to achieve long term well integrity. Both codes mandate that the design basis for wells must:

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

Each Code also mandates monitoring and maintenance requirements, and specifies mandatory well abandonment requirements.

Drilling wells to target the shale play in EP161, Santos proposes to apply the principles and mandatory requirements outlined in the Code of Practice: For the construction and abandonment of petroleum wells and associated bores in Queensland (DEEDI, 2011) – the most rigorous in Australia for well construction and abandonment. The Code of Practice (DEEDI, 2011) mandates the following:

- The petroleum tenure holder must be able to demonstrate that verification of well integrity and barriers exists through maintenance and monitoring through the establishment of a well integrity management system. Monitoring mechanisms and frequencies are to be determined by a risk assessment or asset integrity management guidelines.
- The well integrity management system must outline:
    - Regular wellhead maintenance and inspection for leaks
    - Routine operational visits
    - Monitoring of annuli pressures

- Barrier maintenance and verification
- Risk assessment and response levels for impaired barriers
- Steps for re-establishing barriers when compromised
- Well integrity records to be maintained.

- The petroleum tenure holder is responsible for ensuring current documented records are maintained clearly stating the existing risk level of wells and any other observations related to well integrity. The documented records shall also contain the operational status and completion status of wells.
- In order to continue operating a well which has a certain assigned risk level, a risk assessment must be conducted based on the severity of exposure in line with the petroleum tenure holder's risk assessment process.

Santos will adhere to the principles and mandatory requirements in Queensland's code. The code states the following as good industry practice, which Santos also adheres to:

- Well barriers should be identified and monitored/tested along with their related function and associated acceptance criteria as necessary. The barriers should be maintained as necessary through the well life cycle and re-established / compensated for when impaired. Parameters that could affect well integrity negatively should be monitored.
- Casing and tubing wear due to corrosive fluids and erosion should be assessed during the well life cycle and its impact on well integrity.
- An annulus pressure management plan should be in place for wells with trapped annuli from installation to final abandonment. Monitoring of the annuli should take place periodically by the Petroleum tenure holder over the life of well to allow for effective engineering design for future workover operations.

Pending the outcomes of this Inquiry, Santos would be supportive of legislative or regulatory amendment enabling best practice, including decommissioning best practice. This may include the Code of Practice for Constructing and Abandoning Coal Seam Gas Wells and Associated Bores in Queensland or Guidance and Specifications provided by American Petroleum Institute (API).

Well design, materials selection and construction

Well design, materials selection and construction is highly engineered and controlled, using specialist materials and equipment. This is above and beyond design specifications, materials used and verification testing performed by other industries that drill through aquifers and aquitards such as water bores.

Well construction

Throughout the well design and construction process stringent quality control procedures and testing are employed to ensure the integrity of the well before it is hydraulically fractured. Aspects of the well design and construction phases that ensure well integrity include:

- Design of the well construction considering local sub-surface conditions
- Construction materials suitable for the pressures to which the well will be subjected during in its lifetime
- Down-hole geophysical survey (wireline logging) prior to the installation of well casing
- Using appropriate cementation materials and techniques
- Pressure testing of the casing after installation and cementation, and
- Conducting down-hole surveying (wireline logging) following cementation to confirm integrity (cement-bond log).

These procedures are discussed in Section 3.2.2.

Casing and cementing

The correct construction of a well, especially the casing and cementing process, is crucial in containing contaminants and protecting groundwater. A properly constructed well reduces the likelihood of contaminating zones adjacent to the well because both fluids and gases are confined within the casing (IESC, 2014).

Well integrity relies on the performance of barriers used to achieve zonal isolation. Zonal isolation involves constructing wells to prevent the flow of gas or water between different geological layers. This ensures isolation of hydraulic fracturing fluids and formation fluids from non-target layers and formations. Barrier performance is influenced by well preparation, drilling fluid operations, casing material procurement, casing installation, cement mixture, preparation and cement placement.

The following management controls within the below sections demonstrates that well integrity is established and then maintained throughout the life of the well. This includes materials selection, engineering design, installation methodologies and equipment selection and then construction and operational monitoring and testing. Specifically:

- Casing design installation - during drilling phase
- Cement design and placement - during drilling phase
- Well integrity testing and checks prior to fracture stimulation
- Well integrity monitoring during the fracture stimulation phase
- Well integrity testing, maintenance and monitoring and rehabilitation during the production phase.

Well integrity management and monitoring

Following the construction of the well the key to a successful and contained hydraulic stimulation treatment is a detailed stimulation model. The model is developed using specialist software and calibrated using historical data. During operations real-time monitoring is undertaken by Santos stimulation engineers and expert contractors of each targeted reservoir zone. During stimulation treatment computer assisted live monitoring allows for potential problems (surface or down-hole) to be identified and corrected quickly. In the event that a problem develops on the surface (e.g. leak in line, pumps shut down), the use of live monitoring as a control measure for early detection can prevent the problem from escalating. 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 well's integrity has been compromised and the treatment will be stopped immediately.

In SA, 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.

The stimulation treatments for reservoir layers are modelled using a numerical model / hydraulic simulator. Based on the final pumping schedule from the optimised design, predicted fracture geometry and expected pressures are generated. During the stimulation treatment key parameters such as surface, bottom-hole and annular treatment pressures, proppant concentrations, volume of injected fluid and fluid additives are monitored. The modelled pressures are compared with the actual pressures and the overall pressure response can provide useful information in evaluating the overall fracture growth. Post-treatment parameters are also monitored and are entered into the model following the treatment to achieve a history match and predict the actual fracture geometry. This calibration process is used to refine and improve subsequent designs as part of the management process.

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

- "cased-hole logging", which includes a cement bond log (CBL) or similar evaluation logs from an acoustic device run inside the casing, that transmits and receives a sound signal to test the completeness and quality of the cement bond between the casing and formation wall; and

- Pressure testing, to ensure that a seal has been achieved and that casings have the required mechanical integrity and strength. Pressurising the well bore with water up to ~ 700 atmospheres (70 megapascals) for hold times of ten minutes is typical, but may be higher to exceed maximum expected hydraulic fracturing pressure (ACOLA, 2013).

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

Monitoring impacts resulting from hydraulic fracturing should be undertaken to determine a baseline prior to fracturing then during and after the fracturing event through to after the well has been decommissioned. This includes monitoring well integrity and monitoring the environment surrounding the well for any changes. Well integrity is tested through pressure tests and running cement bond logging (CBL) equipment down the well to check that the cement is still intact (IESC, 2014).

Well integrity can be determined by Mechanical Integrity Tests, for both mechanical and tubular portions of the constructed well, and the effectiveness of the cementing by measuring the absence of presence of fluid movement past the cement. CBLs simply measure whether cement is present or absent and the quality of the cement bond (IESC, 2014).

Well integrity can be checked using CBLs, as recommended by (DEEDI, 2011). These logs are produced by a tool that uses sound waves to measure the quality of the bon d between the casing and the cement placed in the annulus between the casing and the well.

Santos uses AIMS to ensure that the management of operated wells complies with Santos standards and government regulations and to identify any potential well construction or operational issues. AIMS requires regular monitoring of cased, suspended, or producing wells to ensure the effectiveness of well barriers. This surveillance includes visual checks for any leaks at surface and monitoring of annulus pressure. Annulus pressure is the pressure between the different layers of casing. If sustained annulus pressure is identified, this is a signal that a well barrier such as the casing or cement has failed and is no longer effective (Santos, 2016).

The well integrity management system must outline:

- Regular wellhead maintenance and inspection for leaks
- Routine operational visits
- Monitoring of annuli pressures
- Barrier maintenance and verification
- Risk assessment and response levels for impaired barriers
- Steps for re-establishing barriers when compromised
- Well integrity records to be maintained.

Well abandonment and decommissioning

When a well reaches the end of its productive life, it is abandoned and the surface location rehabilitated in accordance with company policies, procedures and all regulatory requirements. For an onshore location, this includes removing all above ground infrastructure including the wellhead, backfilling the cellar, replacing top soil and reprofiling the area (if required). The end goal of any well abandonment program is that there should be minimal evidence that oil and gas operations have taken place. Well abandonment is closely managed at Santos through a number of internal and external processes to ensure that Santos meets its standards and policies. In addition, all well abandonment programs must be approved by the relevant regulatory authority (Santos, 2016).

In order to abandon a well, cement plugs are strategically placed in the well to isolate all hydrocarbon and water containing formations. The combination of cement and steel ensures geological layers are hydraulically isolated (Santos, 2016).

The placement and verification of the integrity of the cement plugs during abandonment is a critical step that is highly regulated in order to ensure that the remaining hydrocarbons cannot leak into overlying formations and cause contamination. After placement, various methods of verification, including mechanical and hydraulic tests, are used to ensure the plugs were placed at the correct location and are providing an acceptable hydraulic seal (Santos, 2016).

Fracture height growth has been extensively measured using microseismic monitoring in the US and Cooper Basin (SA) – average growth of 100 m with maximum typically around 300 – 350 m. No evidence of fracture growth into shallow aquifers has been recorded.

Given the present day stress regime and the hardness and stress state of intervals above the prospective shale in the Beetaloo Basin, fracture propagation is expected to be horizontal with limited potential for vertical growth.

The Beetaloo Basin does not contain significant faults at reservoir depth.

Santos' prospective shale in the Beetaloo Basin is located approximately 1,100 to more than 3,000 m below the regionally important Tindal Aquifer.

Given the fault and stress setting of the basin and significant distance between the shale reservoir and shallow aquifers, the risk of fracture propagation to the aquifer is remote.

Baseline water quality assessments will be undertaken to characterise pre-activity conditions.

7.2 Hydraulic Fracture propagation

Hydraulic fractures are tensile fractures that open in the direction of least resistance (in most cases least principal stress). In situ stresses (present day stresses that originate due to plate boundary forces) control the orientation and propagation direction of hydraulic fractures.

7.2.1 Activity

Hydraulic fracturing improves hydrocarbon flow by creating fractures in the formation that connect the reservoir and wellbore. Hydraulic fractures are caused by injecting fluid into a target rock formation. Fluid is pumped into the formation at pressures that exceed the fracture pressure (the pressure at which rocks break). At the surface, a sudden drop in pressure indicates the fracture initiation, as the fluid flows into the fractured rock.

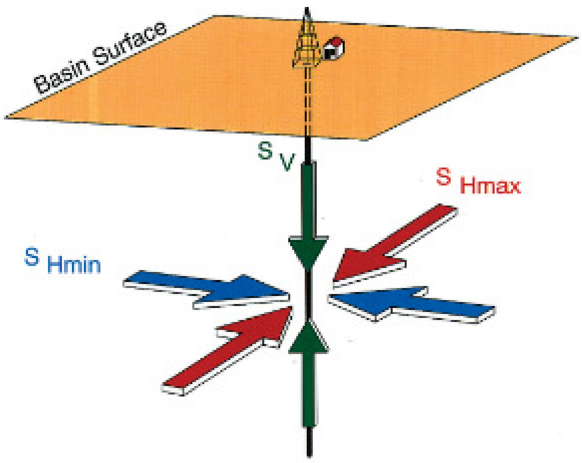
7.2.2 Scientific evidence

The propagation of hydraulic fractures obey the laws of physics relating to stress and strain behaviour of rocks. In situ stresses control the pressure and direction of fracture initiation and growth.

Assuming fluid volume, viscosity and proppant load are consistent then hydraulic fracture formation and propagation are primarily controlled by the present-day stress regime, rock properties, rock heterogeneity and pore pressures (Peska & Zoback, 1995). The orientation and magnitudes of the three principal stresses influence the size and orientation of fractures formed through hydraulic stimulation (Anderson, 1951), (Hubbert & Willis, 1972).

To describe the state of stress at a point in the subsurface, it is necessary to determine the magnitudes and orientations of three orthogonal principal stresses referred to as the largest (S_1), intermediate (S_2) and smallest (S_3) principal stresses (Jaeger, Cook, & Zimmerman, 2007).

Figure 37 Subsurface stresses

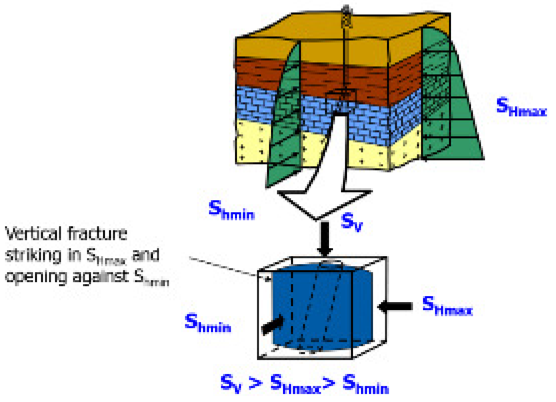


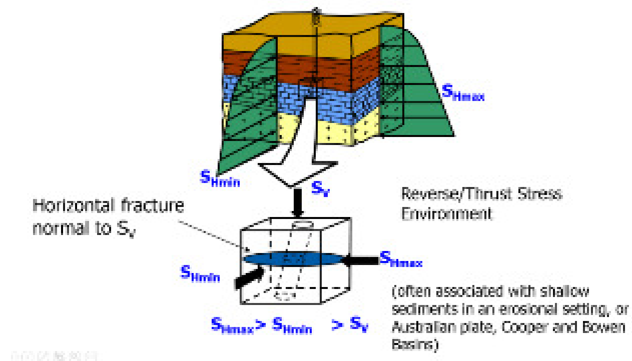
http://ags.aer.ca/publications/chapter-29-in situ-stress Principal Stresses

In normal and strike-slip faulting stress regimes, tensile fractures (such as those induced through hydraulic fracturing) are observed to form vertically, as $S_3 = S_{hmin}$ (Anderson, 1951) (Hossain, Rahman, & Rahman, 2000) (Sibson, 1990), (Zoback, 2007)). In reverse-faulting stress regimes induced tensile fractures are observed to form vertically at the wellbore wall owing to hoop stress effects (Zoback, 2007), before rotating to horizontal as they propagate out of the perturbed stress field surrounding the wellbore as $S_3 = S_V$ (Hossain, Rahman, & Rahman, 2000), (Zoback, 2007), (Hubbert &

Willis, 1972), (Sibson, 1990).

Figure 38 Vertical and horizontal fractures

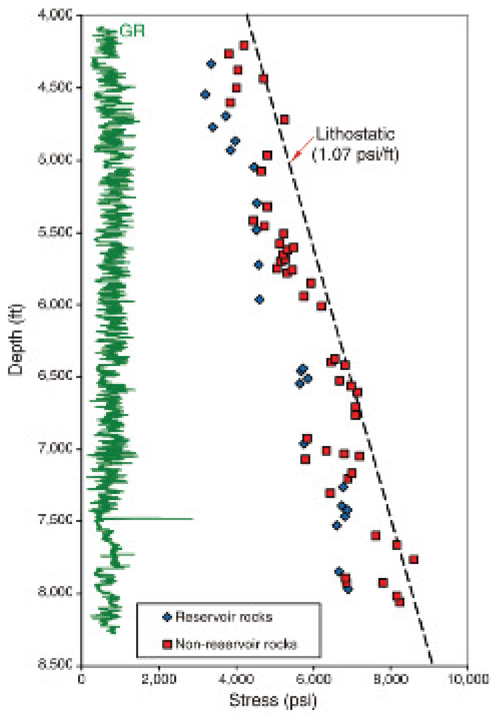




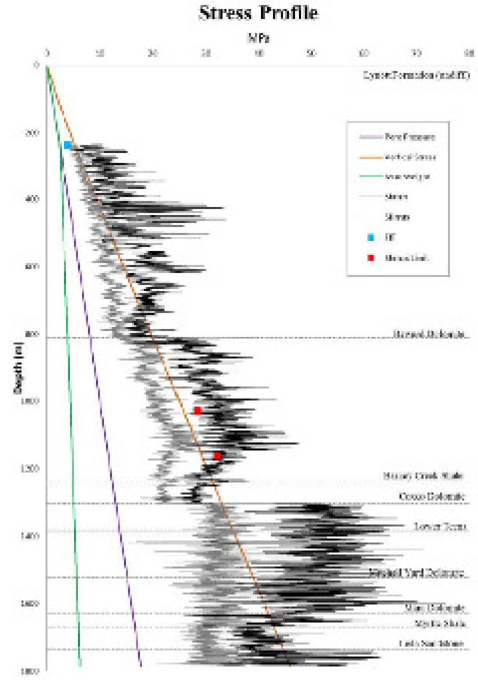
Vertical Fracture – Normal or Strike Slip Stress regime	Horizontal Fracture – Reverse stress regime

Whilst the far-field in situ stress regime is a function of plate tectonic process (Coblentz, Sandiford, Richardson, Zhou, & Hillis, 1995), the stress at a particular wellbore is a function of the plate-scale tectonics and the elastic properties of the rocks intersected by the well. These local stress variations are defined by the poro-elastic stress equations and are referred to as “mechanical stratigraphy” (Blanton & Olsen, 1999)

The importance of stress contrasts to hydraulic fracture growth was recognised very soon after fracture stimulation began (Perkins & Kern, 1961). It has been demonstrated in minebacks (Jeffrey, Byrnes, Lynch, & Ling, 1992), numerical modelling, microseismic and through use of tracer data (Barree, Barree, & Craig, 2007). One of the most complete records of stress with depth comes from the Piceance basin in Colorado (Warpinski, Wilmer, & Branagan, 1985), (Warpinski & Teufel, 1989), (Branagan, Peterson, Warpinski, Wolhart, & Hill, 1997)). The figure below shows that whilst the general trend is increasing stress with depth, large stress variations exist between the reservoir and non-reservoir rocks. High stress units act to “trap” fractures in low stress zones because fractures require less energy to grow against low stress (Veatch, 1983), (Daneshy, 1978) (Warpinski N. S., 1982) and (Miskimins & Barree, 2003). Lithological stress variation was noted in the Cow Lagoon 1 well in the McArthur Basin (Mildren, Clark, & Holford, 2014). It can be seen in the mechanical earth model below that the shale reservoirs are much lower stress than the bounding non-reservoir units.

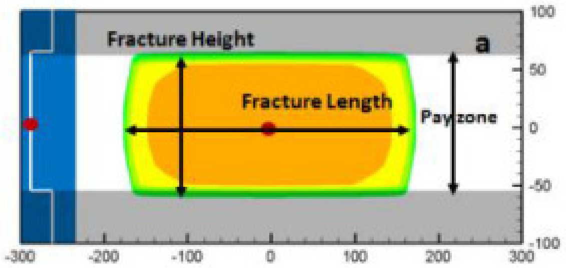


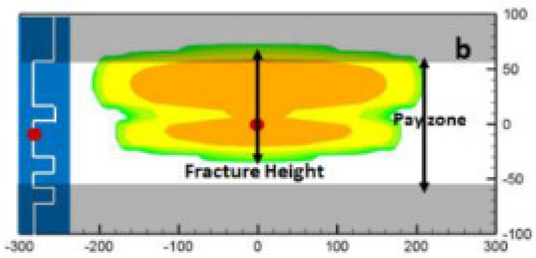
(Fisher & Warpinski, 2011)

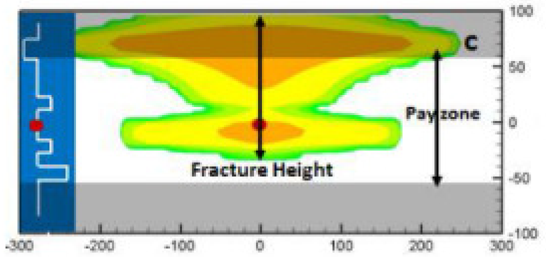


(Mildren, Clark, & Holford, 2014) Cow Lagoon-1 stress profile showing formations.

The impact of mechanical stratigraphy on fracture height growth may be modelled using finite element or similar methods. The figure below shows the impact of stress on hydraulic fracture height growth for a simulated fracture. It shows that complex stress contrast results in irregular fracture geometry and limited height growth (Huang, Ma, Shahri, Safari, Yue, & Mutlu, 2016). Note that the same constant rate and friction reduced water injection is applied for all three cases. However, the fracture geometry (length, height, and conductivity) evolves differently as in situ stress contrast changes.



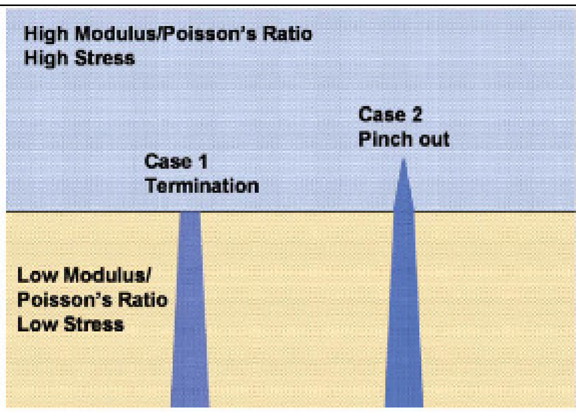




Simulation results with different stress contrasts. White curves represent Shmin profile; red dots indicate well location (Huang, Ma, Shahri, Safari, Yue, & Mutlu, 2016)

Hydraulic fracture height growth may also be impacted by weak interfaces such as are often present at shale/sandstone and coal/sandstone boundaries (Nierode, 1985), (Jeffrey, Byrnes, Lynch, & Ling, 1992), (Zhang, Jeffrey, & Theircelin, 2007). The diagram below shows that as a hydraulic fracture grows, the increasing stress of a bounding layer can cause the fracture tip to pinch out as in Case 2 or completely terminate as in Case 1. As discussed and shown above horizontal stresses will tend to be amplified in the stiffer layers associated with the increased load bearing capabilities. Increased stress will tend to limit fracture growth for similar fracture pressures, due to a lower net pressure acting on the fracture face. In addition, fractures in the stiffer rocks will open less for a given pressure increase, limiting their ability to accommodate fluid. Together the stress and elastic properties define the geomechanical conditions that tend to restrict hydraulic fracture height growth.

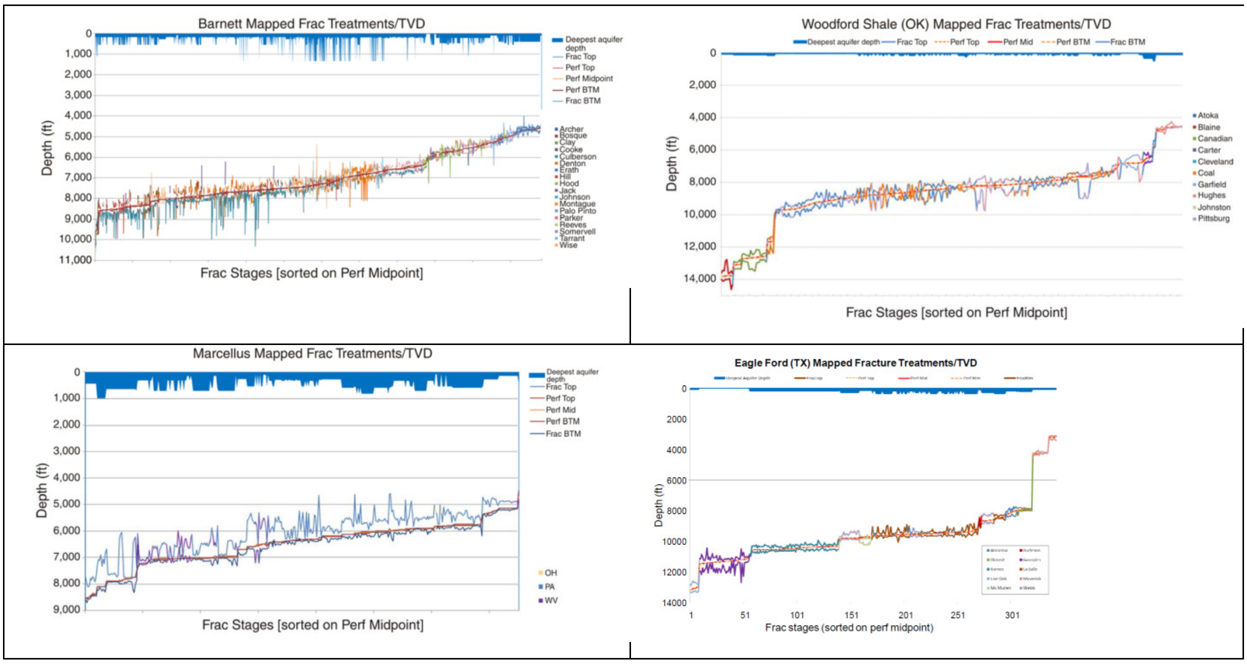
If the bedding plane (either between two lithologies, or within the reservoir itself) is mechanically weak and allows the two layers to move independently, the fracture opening in one layer may not translate to fracture propagation/growth in the second layer. Instead the fracture may either terminate or grow along the interface depending on the geomechanical and hydrodynamic conditions (Case 1 below). Composite layering in rocks tends to limit the overall hydraulic fracture height growth, and fracture simulations have found these to be an equally important factor together with geomechanical variations (Maxwell, 2011) .The combined impact of these factors limits fracture height growth, both for natural and hydraulically created fractures. It is interesting to note that many of the dolerite sills observed in the McArthur Basin utilise a similar mechanism and are often have considerable lateral extent but are confined to the Velkerri Shale (Ahmad, Dunster, & Munson, 2013)., (Krassay, Connors, Pryer, & Jorand, 2013).



Schematic diagram of end member scenarios when fractures grow between layers of different properties member scenarios when fractures grow between layers of different properties (Maxwell, 2011).

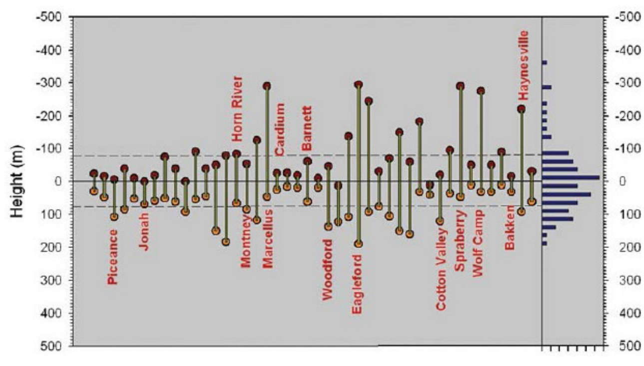
In order to effectively stimulate shale gas wells horizontal wells are drilled towards SHmin. This is to create multiple fractures from the one lateral section to maximise the surface area able to flow gas into the well. Whilst the well geometry does impact on the initiation pressure and fracture geometry it does not impact fracture height growth. This is still constrained by stress and mechanical contrasts in the interburden as described above (Rahim et al. 2012; Moos and Zoback 1990).

Microseismic is often used to monitor height growth associated with Hydraulic Fracturing of shale reservoirs. (Fisher & Warpinski, 2011) summarised thousands of hydraulic fracture treatments in North American Shale plays. Their findings are summarised in the figures below. Each of the graphs illustrates the fracture top and bottom for all mapped fracture treatments from early 2001 to end 2010. All depths are in true vertical depth. The dark red lines illustrate the perforation depths with the mapped fracture top and bottom illustrated by the coloured curves. The deepest reported drinking-water levels in each basin are marked in blue. The presence of faults is generally indicated by large upward and downward growth spikes, but overall vertical growth is still limited to several hundreds of feet and separated from the local aquifers by at least several thousand feet.



Source: (Fisher & Warpinski, 2011)

Other authors have produced similar plots to those above including the one below from (Maxwell, 2011). The graph again shows that the average fracture upward or downward growth is around 100m with a maximum height growth of 300m. In the McArthur Basin at the Tanumbirini 1 location the maximum depth of the base of the potable (Tindall) aquifer is 201m TVD and the midpoint of the Velkerri C (shallowest shale) is 3237 m. There is no example of a hydraulic fracture growing to this height. At the shallowest limit of what might be considered for Shale Gas exploitation the middle Velkerri C shale is at a depth of 1330m and the Base of the Tindall Limestone is at 100m so even at its most shallow point there is enough interburden to contain the hydraulic fracture based on US example.



Hydraulic fracture height growth in established shale reservoirs. Average upward and downward growth are represented by dashed lines (Maxwell, 2011).

Santos modelling in McArthur Basin

Modelling of the in situ stress state in the McArthur Basin is ongoing (currently limited by the low number of well penetrations); however the conclusions to date are consistent with other studies undertaken. Santos geo-mechanical and structural models will be continually updated and refined as more data becomes available through the experience of Santos and other operators.

Santos has also created mechanical earth models (MEM's) across the McArthur Basin to understand the stress distribution between the shales and interburden. Below we summarise our preliminary model for the Santos drilled Tanumbirini 1 well. It should be noted that no DFIT was conducted in

Tanumbirirni so pore pressure estimates have been made using the offset Shenandoah well and validated against the recent Origin Energy well (Close, et al., 2017).

The overall stress state through the shallow section of Tanumbirini 1 is thrust regime shallow (S_{Hmax}>S_{hmin}>S_v) transitioning to borderline thrust/strike slip (S_{Hmax}>S_v>S_{hmin}) with depth. However the Velkerri Shale unit is characterised by much lower stress anisotropy and is modelled to be in a Normal Fault stress state. The stress state in the shales is consistent with those modelled for the Barney Creek and Myrtle shales in the South Nicolson (Johnson, Mildren, Warner, & Titus, 2013) (Mildren, Clark, & Holford, 2014) and the overall stress state is consistent with other geomechanical studies undertaken in the Georgina Basin (Bailey et al, 2017), the South Nicolsen Basin (Johnson, Mildren, Warner, & Titus, 2013), (Mildren, Clark, & Holford, 2014) and the McArthur Basin (Theologou, 1991).

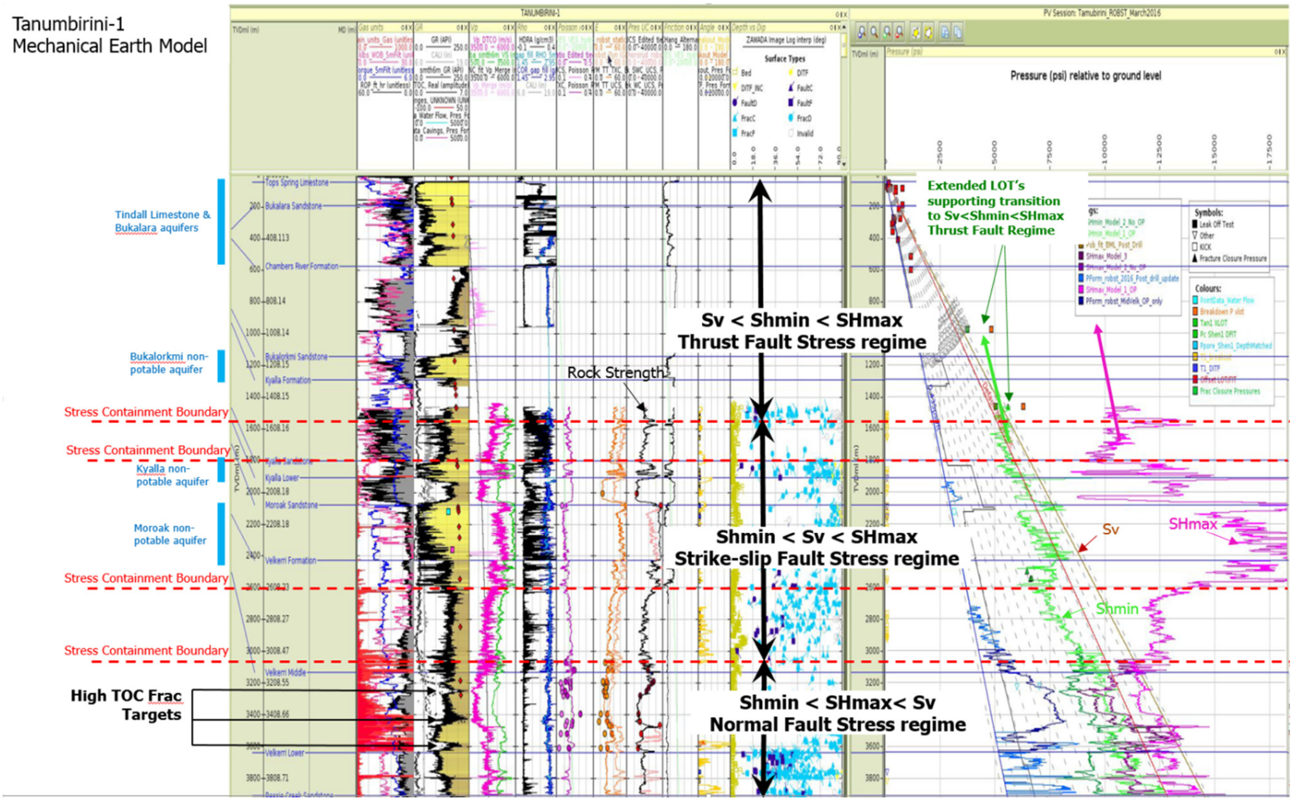
The MEM for Tanumbirini illustrated below incorporates wireline log (eg RhoB, DT and DS), drilling (eg ROP, WOB and Torque), gas, laboratory rock strength tests and leak-off test data. The model shows a range of Pore Pressures illustrating the uncertainty that is associated with the model until a DFIT can be undertaken. The expected case pore pressure used in the model is consistent with the offset Shenendoah well (0.75 psi/ft) and the (shallower) recent Kalala S-1 well (0.52 – 0.55 psi/ft; (Close, et al., 2017). Although the log coverage in Tanumbirini 1 doesn't extend to the shallow aquifer units at Tanumbirini-1 the two extended leakoff test results are indicative of a reverse stress regime. The model suggests that this stress state exists from surface to the upper Kyalla formation. As discussed above, in a reverse stress-state the tendency is for fracture treatments to propagate as a horizontal "pancake" due the principal stress with the least magnitude being overburden (S_v). The aquifers of the Bukalormi and Bukalara Sandstones as well as the Tindall limestone are interpreted to be in this reverse stress state.

Below the Upper Kyalla, the stress state is dominantly strike-slip to the middle Velkerrie Formation although a zone at the top of the Moroak sandstone exists where a thrust stress state is modelled to exist over an ~20-30m interval. The change in stress state is due to the extremely high rock strength and Youngs modulus in the Moroak as measured in laboratory tests and shown in the model. The combination of high stress, hard rock and thrust regime suggests it is likely that any hydraulic fracture that propagated upward from a depth deeper than the Moroak would not penetrate this unit.

Below ~3050m TVDBGL in the Velkerri shale unit the stress state changes again to be dominantly a Normal Fault stress regime. The high total organic carbon (TOC) reservoir targets reside in this interval and rock strength testing has shown much lower rock strength than the sandstone units of the Moroak and Kyalla Formations. The lower stress and rock strength is partly due to the mechanical properties of the shale (higher Poisson's ratio, lower Young's modulus) due to the organic content of the shale and also the elevated pore pressure which resists the compaction effects of a very high overburden gradient. Lower rock strength and a normal fault stress-state should result in good hydraulic fracture placement that is dominantly confined to the reservoir.

In summary, in the McArthur Basin the Velkerri shale is at lower stress than the bounding sandstones and siltstones. A number of stress contrasts at varying scales exist to provide adequate overburden containment of any vertical fracture propagation. It is therefore unlikely that the hydraulic fractures can grow very much out of zone, if at all. A Groundwater and Geophysical Research Letters paper by Flewelling et al. conducted in 2013 found: "It is not physically plausible for induced fractures to create a hydraulic connection between deep black shale and other tight formations to overlying potable aquifers, based on the limited amount of height growth at depth and the rotation of the last principal stress to the vertical direction at shallow depths (Flewelling, Warpinski, & Tymchak, 2013)." Santos modelling suggests this statement is true for fracture stimulation in the Velkerri Shale in the McArthur Basin as well.

Figure 39



Santos experience in horizontal fractured wells

Operators design hydraulic fracture stimulation treatments to control fracture propagation and to ensure that the hydraulic fracture stays within the reservoir and does not grow into the adjacent formation. Engineers carefully monitor the stimulation process to ensure it goes safely and as planned by tracking small fragments of rock the break (as fracturing fluid forces the rock to crack) causing tiny seismic emissions (microseisms).

The table below summarises the horizontal wells drilled and fracture stimulated as part of exploration campaigns in onshore Australia. Santos has fracture stimulated 4 horizontal wells in the Cooper Basin. Roswell 2 (Roseneath Shale), Moomba 193 (Murteree Shale), Cook 29 (Murta Oil), Merrimelia 64 Murta Oil. Moomba 193 had a 1,000 m lateral drilled into the Murteree Shale (2,742.6 m TVD), 10 stages were stimulated. Roswell 2 had a 500 m lateral drilled into the shallower Roseneath shale over 5 stages.

High angle wells with lateral lengths deviated more than 75 degrees have also been stimulated including Moomba 118 DW in the Cooper Basin and 32 coal seam gas wells in the Bowen Surat Basin in QLD. None of the stimulated wells have had hydraulic fractures propagate into the shallow aquifers.

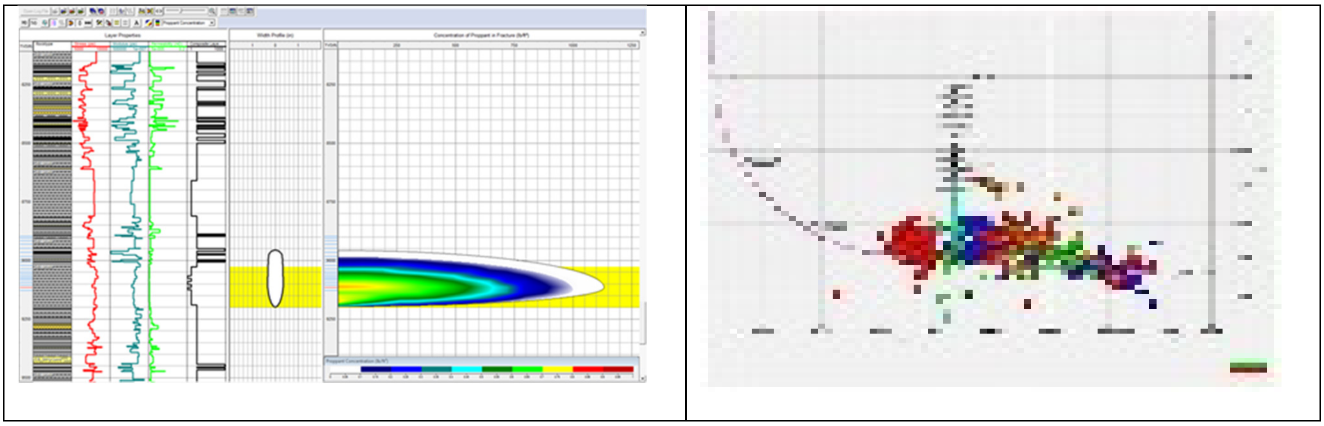
Table 7 Horizontal wells drilled and fracture stimulated as part of exploration campaigns in onshore Australia

Well	Operator	Formation	Approx. Lateral length	Stimulation stages
Boston 3	Beach	Basin Centered Gas		1
Holdfast 2	Beach	Murteree Shale	600 m	7
Moomba 193H	Santos	Murteree Shale	1,000 m	10
Roswell 2H	Santos	Roseneath Shale	500 m	5
Baldwin 2H	Petrofrontier	Arthur Creek "hot shale"	876 m horizontal	10
MacIntyre 2H	Petrofrontier	Arthur Creek "hot	1,023 m	9

Well	Operator	Formation	Approx. Lateral length	Stimulation stages
		shale"	horizontal	
Owen 3H	Petrofrontier	Arthur Creek "hot shale"	966 m horizontal	10
Egilabria 2 DW1	Armour	Lawn Hill Shale	587 m	8
Amungee NW 1	Origin	Velkerri Shale	1,000 m	11

Surface and downhole microseismic and tracers were used to map hydraulic fracture growth in Moomba 193, the largest fracture height was 76.2 m, which appeared to be reasonably well centred in the shale interval with upward growth of around 38.1 m (Camac, Donley, Waldron, & Hunt, 2012). When compared with the pre-fracture simulation the containment matched the model well, with the exception of a few events located within 250m TVD of the wellbore.

Figure 40 Stimulation in Moomba 193 showing the pre-fracture simulation



The Moomba 193 well is a good analogy to the proposed hydraulic fracture stimulations in the NT. The stages pumped averaged 50,000 gallons versus the 417,500 gallons proposed for the OT Downs stimulations as per the schedule below. The stress state in the Cooper Basin is similar to that of the McArthur Basin. An example MEM from the Moomba Field has been included below and it can be seen that whilst the stress in the Murteree is higher overall than in the Velkerri (figure above), the fractures still did not grow into any of the lower stress units either above or below the shale which are within a closer proximity than any groundwater systems are to the Velkerri in the McArthur Basin.

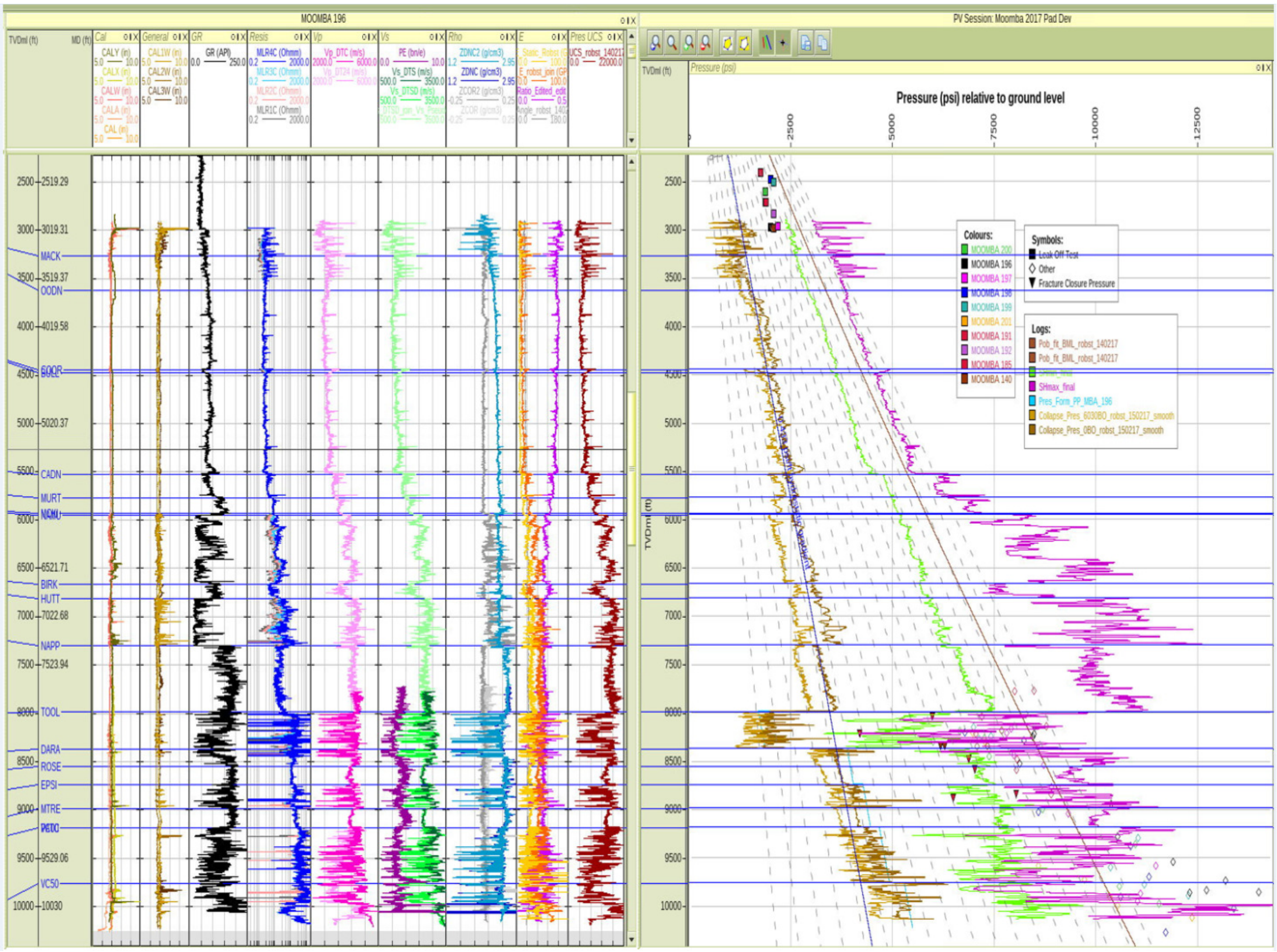
Figure 41 Hydraulic fracture staging schedule

Standard Design - Slick 300 klb

Stage	Fluid Type	Description	Clean Vol (gals)	Prop Conc (lb/gal)	Prop Type	Proppant (lbs)
1	Linear	Breakdown	1000			0
2	7.5% HCl	Acid Spearhead	1500			0
3	Linear	Pad	30000			0
4	Linear	Pad	30000	0.25	100 Mesh Sand	7500
5	Linear	Pad	30000	0.50	100 Mesh Sand	15000
6	Linear	Pad	30000			0
7	Linear	Slurry	30000	0.10	Main Proppant	3000
8	Linear	Slurry	30000	0.25	Main Proppant	7500
9	Linear	Slurry	35000	0.50	Main Proppant	17500
10	Linear	Slurry	35000	0.75	Main Proppant	26250
11	Linear	Slurry	35000	1.00	Main Proppant	35000
12	Linear	Slurry	35000	1.25	Main Proppant	43750
13	Linear	Slurry	35000	1.50	Main Proppant	52500
14	Linear	Slurry	30000	1.75	Main Proppant	52500
15	Linear	Slurry	30000	2.00	Main Proppant	60000
						0
						0
						0
						0
Total			417500			

Stage Type	Rate	Prop Conc	Clean Vol	Stage Length	Cumm Time	Fluid Type	Proppant Type
Main frac pad	5	0.00	1000			20#WG-11	
Main frac pad	5	0.00	1500			7.5%HCl Acid	
Main frac pad	60	0.00	30000			20#WG-11	
Main frac pad	60	0.25	30000			20#WG-11	100Mesh
Main frac pad	60	0.50	30000			20#WG-11	100Mesh
Main frac pad	60	0.00	30000			20#WG-11	
Main frac slurry	60	0.10	30000			20#WG-11	40/70 ISP
Main frac slurry	60	0.25	30000			20#WG-11	40/70 ISP
Main frac slurry	60	0.50	35000			20#WG-11	40/70 ISP
Main frac slurry	60	0.75	35000			20#WG-11	40/70 ISP
Main frac slurry	60	1.00	35000			20#WG-11	40/70 ISP
Main frac slurry	60	1.25	35000			20#WG-11	40/70 ISP
Main frac slurry	60	1.50	35000			20#WG-11	40/70 ISP
Main frac slurry	60	1.75	30000			20#WG-11	40/70 ISP
Main frac slurry	60	2.00	30000			20#WG-11	40/70 ISP
Main frac flush	60	0.00	10000			20#WG-11	
Shut-In	0	0	0	5			

Figure 42 Hydraulic fracture modelling



7.2.3 Santos and industry mitigation

Fracture growth is highly dependent on the conditions at the site, including the geology, in situ stress and injection pressure. Various methods can be used prior to and during hydraulic fracturing to design and control fracture growth. In addition, ensuring well integrity is important in protecting the environment.

The risk of migration of gas or fluids to aquifers and surface waters is a major concern with gas extraction and associated fracturing operation. The process of hydraulic fracturing brings the risk that fracturing may allow the migration of fluids, oil or gas through rock strata to contaminate aquifers (Hawke, 2014).

Petrophysical logs, rock strength testing and leak-off tests have been used to constrain the present day stress and mechanical stratigraphy at the Tanumbirini 1 well location. The shallow potable aquifers of the Tindall formation are located in a reverse stress regime which extends into the upper Kyalla formation. It is anticipated that any hydraulic fracture initiated within this unit would propagate horizontally rather than vertically. This means there could be no interaction between the deeper Velkerri Shale formation and the shallow Tindal aquifer which are separated by a minimum of 1230m at the shallowest limit of what might be considered for Shale Gas exploitation in the Greater Beetaloo Basin.

Several high stress sandstone intervals that will also act as barriers to vertical fracture growth exist between the Velkerri Shale and the Upper Kyalla formation. It is also likely that weak horizontal bedding boundaries exist within the shale units that will also retard vertical fracture growth. This is somewhat analogous to the dolerite sills which appear to travel significant horizontal distances along weak boundaries in the Velkerri Shale (Sever 1 well (Krassay, Connors, Pryer, & Jorand, 2013).

The only exception to the above discussion on vertical growth of hydraulic fractures in the Velkerri Shale Play would be if hydraulic fractures were to grow along existing faults. However, as with the US shales, the increase in height growth would be expected to be very minor where faults of sub-seismic resolution are encountered.

It should be noted that the modelling work done by Santos is preliminary due to minimal well data and particularly DFIT and mini-frac data. However the conclusions made are consistent with other studies undertaken in the Georgina Basin (Bailey, Tenthorey, & Ayling, 2017), the South Nicolsen Basin (Mielke, Anadon, & Narayanamurti, 2010), the McArthur Basin (Theologou, 1991). The Santos geomechanical and structural models will be continually updated and refined as more data becomes available through the experience of Santos and other operators.

The potential risk of induced seismicity in the Beetaloo Basin from hydraulic fracturing is considered remote and unlikely due to:

- *Relative seismic stability of the NT region*
- *No significant faults extending to reservoir depth*
- *Induced seismicity from hydraulic fracturing is rare.*

Potential risk can be effectively mitigated by understanding the stress setting; this has been done and stress regime in the McArthur Basin (NT) assessed as low risk.

Globally, only two cases of "felt" induced seismicity have been confirmed to have been caused by hydraulic fracturing for shale gas development; both events due to hydraulic fracture growth into pre-existing critically stressed faults.

The Oklahoma Geological Survey (OGS) claims that an increase in the frequency of earthquakes since 2009 is triggered by the injection of produced water and not from hydraulic fracturing; OGS states "only a small percentage of the water injected is generated from hydraulic fracturing".

7.3 Induced seismicity

Induced earthquakes are those triggered by human activities, including filling of large water reservoirs, mining and activities involving pumping fluids into and out of subsurface reservoirs, such as required in hydrocarbon, geothermal energy and some water resource activities.

Induced seismicity from (uncontrolled) fracture propagation is recognised as a potential risk of shale gas production (Healy, 2012). The changes to rock fractures and deformation due to hydraulic fracturing induced seismicity may change the pathways for groundwater, gas and contaminant flow (Beck Engineering, 2013). This could result in the migration of contaminants from the formation into adjacent aquifers via these new fractures.

7.3.1 Activity

As hydraulic fracturing is undertaken in shales, movement and stress changes occur within the formation (Beck Engineering, 2013). When fractures in rock are generated or deformed, the existing stress state in the rock changes resulting in some seismic activity. This is referred to as seismicity induced by hydraulic fracturing (or induced seismicity).

Monitoring of microseismic events provides an important mechanism for mapping and modelling fracture propagation.

The nature of the shale or similar rocks targeted for fracturing limits the magnitude of seismicity (shale does not require much energy to build up before breaking), as does the depth at which fracturing occurs. The pressure effects leading to seismicity are also constrained by the limited volume of rock affected, the limited timescale, and dissipation of pressure as fractures are created (Zoback, 2012).

Inducing a seismic event requires a triggering event that will increase the shear stress, reduce the normal effective stress on the fault and/or reduce the fault frictional resistance. However, to cause a significant event requires activating slip over a large enough area (e.g. a seismic event of magnitude (M) 4), involves a fault area of about 1.4 km^2 and a slip of about 1 m (NAS, 2012).

Although induced seismicity may not be of sufficient magnitude to be felt (or damaging) at the surface, there is a risk of damage to well integrity, if the well casing is deformed at depth (The Royal Society and Royal Academy of Engineering, 2012), (Hawke, 2014).

Larger seismic events induced by hydraulic fracturing can occur when pressure effects intersect an existing pre-stressed fault, causing it to "slip" and release stored energy.

The consensus is that any seismicity induced by fracturing is unlikely to be at a magnitude greater than -3ML (Green, Styles, & Baptie, 2012), which is felt by few people and results in negligible, if any, surface impacts (Hawke, 2014).

A good understanding of fault structures in the vicinity of the fracturing operation is therefore desirable and best practice would include mapping local fault structures with 3D seismic and avoidance of fracturing adjacent to active faults. The risk of seismic events can be minimised by understanding the local subsurface fault system and seismic history of a region, appropriate site selection and monitoring of pressure changes in a well before, during and after hydraulic fracturing (IESC, 2014).

Santos has no plans for water injection in the NT at this stage. Any future water injection plans will be subject to a range of comprehensive hydrogeologic and geochemical studies and government assessment and approval before implementing. Induced seismicity as a result of waste-water is summarised below for reference and comparison with fracture stimulation only.

7.3.2 Scientific evidence

Induced seismicity has been addressed in some studies (National Academy of Sciences, 2012), (Leith, 2012) and other hydraulic fracturing inquiries (The Royal Society and Royal Academy of Engineering, 2012), (ACOLA, 2013) which have concluded that the risks are small: "… the process of hydraulic fracturing a well as presently implemented for shale gas recovery does not pose a high risk for inducing felt seismic events" (Leith, 2012).

No microseimic or seismic activity related to hydraulic stimulation of shales has been recorded as having any impact on groundwater systems as a result of these events (NAS, 2012). The US data referenced throughout this paper indicates that faults do not provide a mechanism whereby created fractures are able to propagate significantly upwards, towards the surface. Even in the presence of faults overall vertical growth is still limited to several hundreds of feet and are separated from the local aquifers by at least several thousand feet (Fisher and Warpinski, 2011).

Hydraulic fracture induced seismicity

In 2012, the US National Research Council on behalf of the US Department for Energy conducted a review entitled "Induced Seismicity Potential in Energy Technologies" (NAS, 2012).This review found that 35,000 hydraulically fractured shale gas wells existed at the time in the US and of these wells only one case of felt seismicity (magnitude (M) 2.8) had been described in which hydraulic fracturing for shale gas development was suspected, but not confirmed, as the cause (Holland A. , 2011). Whilst there is no confirmed cases in the US, confirmed cases of "felt" induced seismicity have been reported globally.

Globally, only two cases of "felt" induced seismicity have been confirmed to have been caused by hydraulic fracturing for shale gas development. These include Preese Hall 1 well in England (M 2.3) and a fracture stimulation in the Tatoo region of the Horn River Basin in British Columbia (M 3.8). Both these events are believed to have been due to hydraulic fracture growth into critically stressed faults. Neither of these events had an effect on shallow aquifers or the environment (BC Oil and Gas Commission, 2012), (Green, Styles, & Baptie, 2012). Evidence for the lack of impact on shallow aquifers is through microseismic monitoring during the hydraulic fracture stimulation operation.

The first event occurred at the Preese Hall-1 well in the Blackpool area of England, in 2011. The earthquake was felt in northern England and was widely reported in the press. The well was drilled and hydraulically fractured by Cuadrilla Resources to explore the gas potential of the Bowland Shale Formation. The Preese Hall-1 exploration well was stimulated vertically to 9,004 feet measured depth with five hydraulic fracture stages. The M 2.3 event occurred during stage 2, and the M 1.5 occurred during stage 4. In addition, approximately 50 weaker events were detected after additional seismic stations were deployed (Pater & Baisch, 2011).

Cuadrilla Resources initiated an extensive study of the incident, including installing portable seismic stations and a detailed seismic analysis as well as geomechanical studies and core studies, which were released to the public on their website. The research determined that the hydraulic fracturing induced the seismic events. The hydraulic fracturing is believed to have reactivated a nearby, apparently unstable fault (Harper, 2011) (Pater & Baisch, 2011).Bedding at the well location was significantly steep and was shown to have signs of previous slip in core. The fracture is believed to have grown along the steep bedding plane and intersected the fault away from the well (Pater & Baisch, 2011).

At Preese Hall 1 it was also shown that there was substantial impermeable rock between the reservoir and the aquifers and the aquifers themselves that shale smear and the "tight-rock on tight-rock" geometry would not facilitate fluid flow or cross-flow. This is consistent with the geology in the McArthur basin and the overburden above the Velkerri shale play (Pater & Baisch, 2011), (Green, Styles, & Baptie, 2012), (Geoscience Australia, 2017).

The second confirmed example of felt seismicity being induced during fracture stimulation in shale was in the Horn River Basin in British Columbia between Dec 8 and Dec 13 in 2011. The events ranged between M 2.2 and M 3.8. An investigation into the events was conducted by the BC Oil and Gas commission in 2012. They determined that the induced seismicity was caused by fluid injection during hydraulic fracturing in proximity to pre-existing faults. Analysis of the microseismic data by the Commission found that fracture growth was confined to the target shales except where the fractures grew downward into fault zones (BC Oil and Gas Commission, 2012).

Another possible earthquake sequences that may be associated with hydraulic fracturing in shale was recorded in Oklahoma, in 2011. The largest event was M 2.8 ((Holland A. , 2011)). The close proximity and timing of the earthquakes to the hydraulic fracturing well suggested a possible, but not fully established, link. However, the quality of the event locations was not adequate to fully establish a direct causal link to the hydraulic fracture treatment.

Potential for induced seismicity

As discussed above, the likelihood for induced seismicity due to fracture stimulation in shales globally is extremely low. In the few documented cases in the literature where “felt” seismicity has been proven or even possibly related to hydraulic fracturing in shale there has been no disruption to aquifers of groundwater systems.

As shown in Section 5.1.4, the McArthur Basin is seismically stable, with all seismic activity in recorded history located well away from the Velkerri shale target region and basin bounding faults. In addition to this, current subsurface geological fault interpretation does not contain significant faults at reservoir depth that could interfere with ground water systems (Northern Territory Government, 2017).

In the case of the Blackpool (UK), the hydraulic fracture was shown to have re-activated a pre-existing fault. The reactivation pressure of a fault depends on the orientation of the fault within the present day stress environment and the mechanical properties of the fault itself (Jaeger, Cook, & Zimmerman, 2007). Whilst there have been studies conducted on the in situ stress in the McArthur Basin ((Mildren, Clark, & Holford, 2014)) no specific study has been done yet on the reactivation potential of the basin bounding faults; however the Basin Bounding faults in the McArthur are currently sealing. This is evidenced by the significant overpressures that have been maintained in the Velkerri shale for over 1400 million years as documented in Shenandoah and Amungee wells (McConachie et. al. 2015; (Close, et al., 2017). In the Velkerri Shale play, bedding dip is close to horizontal (to a maximum of 10 degrees) with no unstable faulting identified within the proposed development area of the OT Downs sub-basin relegating the risk of reactivation to very low.

Other than the basin bounding faults, the OT Downs Sub-basin is reasonably unstructured. There are likely to be smaller more localised faults throughout the Basin, however as discussed above, Fisher and Warpinski (Fisher & Warpinski, 2011) show that even where these local faults exist the maximum hydraulic fracture growth evidenced by the microseismic) is a maximum of 2,000 ft (607m). In the McArthur Basin at the Tanumbirini 1 location the maximum depth of the base of the potable aquifer (Tindall Limestone) is 201 m TVD and the midpoint of the Velkerri C (shallowest shale) is 3,237 m. Even at the shallowest limit of what might be considered for Shale Gas exploitation the middle Velkerri C shale is at a depth of 1330 m and the base of the Tindall Limestone is at approximately 100 m. Even at its most shallow point there is enough interburden to contain a hydraulic fracture that is influenced by a sub-seismic fault.

It should also be noted that in the case of the Blackpool seismicity, despite the reactivation, the fault remained impermeable. Fault permeability is low in regions where shale content is high (Yeilding, Freeman, & Needham, 1997). This is the case in the McArthur Basin. In the Tanumbirini 1 well location the total shale in the well is greater than 60%. Whilst no studies have yet been completed it is highly likely that this volume of shale will prevent juxtaposition of sandstones and provide shale smear that would prevent flow of fluid along the fault plane (as has been the case with the Basin bounding faults for the past ~350 million years).

7.3.3 Santos and industry mitigation

To minimise risks associated with induced seismicity, potential mitigation may comprise:

- Develop the necessary scientific background on stress, mechanical stratigraphy, seismicity and structural geology, including:
  - Mapping and characterising stresses and faults (orientations and slip tendencies)
  - Mapping direction of bedding planes within the shales

  - Updating mechanical earth models with new data
  - Using “best practice” to simulate hydraulic fracture growth and refining these with microseismic data
- Building ground motion prediction models for affected regions.

It is important to place the scale of water requirements for hydraulic fracturing in the context of other water uses. (Moore, 2012) estimated that the water requirement of a shale gas well over a decade was equivalent to that needed to water a single golf course for one month, or to run a 1000 MW coal-fired power plant for 12 hours.

Of all major energy sources, natural gas produced from shale is among the least water consumptive energy resources per MMBTU (Range Resources, 2017).

Important aquifers within the region include the Cambrian aged Anthony lagoon Beds and Gum Ridge Formation (both limestone aquifers).

Resource companies actively exploring in the Beetaloo Basin/OT-Downs in the NT (including Santos) are entering into an agreement with the CSIRO to establish a coordinated research 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.

7.4 Water use, supply and containment

Water use, and competition for water resources with other current and potential users and environmental requirements, is recognised as a potential significant issue for shale gas development and hydraulic fracturing.

Groundwater and surface water values in the target area, discussed in Section 5.2, represent valuable resources for the NT and mitigation measures are covered for each of the related risk themes in Appendix A. This section discusses the specific activity of water use, supply and containment as it relates to hydraulic fracturing and, with supporting evidence, demonstrates how Santos and industry mitigation reduces these risks to an acceptable level.

7.4.1 Activity

In shale gas development, water is required during drilling of the well and then for each hydraulic fracture stage. Water is sourced locally and stored on site in temporary engineered containment structures before mixing with proppant and chemical additives for hydraulic fracturing.

Once the well is complete and producing, there are no planned water requirements at the well, unless one of the workover scenarios listed in Section 3.2.4.1 are required. It is noted, unlike coal seam gas, no groundwater extraction is required to depressurise and release shale gas.

7.4.2 Scientific evidence

Water requirement

Hydraulic fracturing of shale gas formations requires volumes of water to transmit the proppant down the well and into the formation. The volume of water used during hydraulic fracturing is dependent on several factors including the type of well and the depth at which fracturing occurs, the number of fracturing stages, the fracturing fluid composition and the local geological conditions.

In the USA, hydraulic fracturing in the Marcellus shale gas play (analogue) requires, on average, about 17 ML per well (Beauduy, 2011) (Pacific Institute, 2012) to 20 ML per well (Chesapeake Energy, 2010); with the median volume per shale gas well in four USA shale gas plays ranging from 10.6 ML to 21.5 ML (Beauduy, 2011) (Nicot & Scanlon, 2012). Whereas, the scientific assessment of shale gas development in the Central Karoo district of South Africa, reported each well requires in the order of 10.5 ML of water to be fractured (Scholes, 2016). Beach Energy indicated in its submission to the SA Inquiry that typical fracture stimulation in low-permeability shale in the Cooper Basin (SA) requires 1.3 ML to 1.6 ML per treatment (Beach Energy, 2015). For conventional wells in the Cooper Basin (SA), Santos has indicated water consumption of 1 ML for each fracturing stage.

Hydraulic fracturing requires access to volumes of water that are generally not large compared to other uses, such as irrigation, large industrial users and town water supply. Data from the Australian Bureau of Statistics (ABS) shows that agriculture has consistently consumed the largest volume of water in the NT, and more than half of Australia's water consumption (ABS, 2011).

As part of independent research in the United Kingdom (UK), Moore (2012) estimated that the water requirement of a shale gas well over a decade (19 ML) was equivalent to that needed to water a single golf course for one month, or to run a 1000 MW coal-fired power plant for 12 hours. Compared to other energy resources, the water intensity of natural gas produced from shale was found to be relatively low (Mielke, Anadon, & Narayanamurti, 2010) (Range Resources, 2017). In Pennsylvania, USA, shale gas extraction (based on 800 well completions per year) made up 0.1% of consumptive water (Kenny, Barber, Hutson, Linsey, Lovelace, & Maupin, 2009) compared to 0.65% for livestock, 1.0% for mining, 1.6% for domestic water supply, 5.5% for public water supply, 5.5% for aquaculture, 8.1% for industry and 67.8% for thermoelectric power (Hawke, 2014).

Water source

Water that is not potable or only suitable for stock use (i.e. due to higher salinity) may be usable for hydraulic fracturing. Alternatively, blending of water sources may be possible. There are some technical difficulties in mixing fracturing fluid that can meet the required functions using saline water, and this is an area of current research and development, although seawater is already sometimes used for fracturing in offshore production. (King & King, 2013) described an example in British Columbia of fracturing operations that used sour brine (high Cl and H_2S) from deep (2440 m) formations, in a closed loop system that also minimised water storage requirements (Hawke, 2014).

In the Marcellus Shale Play, Range Resources (Range) maintains a robust water-recycling program that uses permanent and temporary water transfer pipelines which significantly reduces truck traffic. Additionally, when trucks are used during water transfer, Range requires reduced idling times at its locations. Trucks are tracked by satellite to promote efficient and safe operations possible. Water is closely monitored and regulated in the states where Range operates (Range Resources, 2017). In 2009, Range pioneered technology that allows for the recycling and reuse of nearly 100 percent of the water across its Pennsylvania operations. Today, these recycling practices have become more common across our industry, greatly expanding the environmental and economic benefits (Range Resources, 2017).

Developments in hydraulic fracturing and water management methods are likely to lead to a reduction in total water use per well and/or a reduction in conflict with other potential users. Flowback water (and subsequently process water) can be reused for subsequent fracturing operations if it can be treated to the required standard in an economically viable way (Section 5.5). Santos informed the Inquiry that water recycling was introduced as standard practice in fracturing operations in the Moomba field by 2015 (Santos, 2017).

In addition to the mitigation measures discussed above, water resource monitoring can be undertaken to proactively manage water use, supply and containment.

Water containment

Various reviews have indicated the impact of any accidental releases, leaks and/or spills of flowback water and hydraulic fracturing fluid may be mitigated by adopting standard or best practice management practices (The Royal Society and Royal Academy of Engineering, 2012).

Such practices include conducting regular maintenance of infrastructure and equipment associated with managing flowback, ensuring ground pits (turkeys nests) or tanks are of sufficient size to store the volume of flowback and lining storage ponds to minimise seepage to shallow groundwater aquifers (DEEDI, 2011).

7.4.3 Santos and industry mitigation

Water sourcing

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

- Recycled flowback water
- Surface water sources in accordance with permits and approvals
- Local boreholes (which will draw the water from groundwater) in full consultation with the land holder or in accordance with permits or approvals, and/or
- Other supply (i.e. trucked to site).

Important Aquifers within the region include the Cambrian aged Anthony lagoon Beds and Gum Ridge Formation (both limestone aquifers). Without adequate assessment and management controls in place, there is the potential risk for perceived or actual impacts to groundwater users.

Bore owners are to be consulted and relevant authorisations obtained from the NT Government prior to undertaking works on existing bores or sinking new water bores (where required).

Santos will not obtain water from an aquifer where there is a risk of adverse impact to other users of water or groundwater water dependant ecosystem that can't be mitigated or managed or made-good.

With advances in fluid chemistry, high quality water (i.e. potable) is no longer required for hydraulic fracturing. This facilitates opportunities for reuse or recycling of flowback water or blending water from various 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 5.5 GL (assumes 50% flowback recycling) to 11 GL (no recycling) over 30 years(refer to Figure 21 in Section 4.3). This equates to an average of approximately 183 ML/year to 367 ML/year respectively. The underlying assumption is that 1 ML 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 35 ML per well has been used.

Baseline assessment

Resource companies actively exploring in the Beetaloo Basin/OT-Downs in the Northern Territory (including Santos) are entering into an agreement with the Commonwealth Scientific and Industrial Research Organisation (CSIRO) to establish a coordinated research 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/OT-Downs area and include sufficient area around these permits to apply a more regional understanding of groundwater, including water quality.

The CSIRO has extensive experience in managing integrated and diverse research programs including the monitoring of environmental variables, conducting bioregional assessments and characterising unconventional hydrocarbon resources. The Project will link closely with established research programs, including the CSIRO led GISERA program (http://www.gisera.org.au/) which undertakes research into the social, economic and environmental impacts of the natural gas industry; and through CSIRO's collaboration with the federally funded Bioregional Assessments Programme (http://www.bioregionalassessments.gov.au/) whose goal is to provide transparent scientific information to better understand the potential impacts of coal seam gas and coal mining developments on water resources and water-dependent assets such as wetlands and groundwater bores.

Baseline assessments are intended to:

- Provide a measure of security for both bore owners and resource tenure holders by providing information about the current condition and pumping capacity for a water bore.
- Provide a reference point for comparison with subsequent bore assessments to assist in the negotiation of make good agreements and assist in the development of underground water data modelling.
- Assist in resolution of any future disputes that may arise between bore owners and resource tenure holders following a bore assessment or in the negotiation of a make good agreement.
- However, it should be noted that comparison with baseline assessments will be only one consideration when determining impaired capacity through bore assessments.

Previous projects undertaken by Santos, such as the Narrabri Environmental Impact Statement (EIS) and Santos GLNG Gas Field Development Project EIS included a Water Baseline and Water Monitoring Plan. These assessments as part of the EIS demonstrate compliance against performance criteria to protect water quality, quantity and other associated values.

The Santos GLNG Gas Field Development Project EIS also contained a Stimulation Impact Monitoring Plan and an overview is provided in Section 7.6.3. A stimulation impact monitoring plan includes steps to determine a baseline prior to fracturing then during and after the fracturing event through to after the well has been decommissioned (IESC, 2014).

Water management

Santos' sustainable approach to water management revolves around a hierarchy of avoidance and reduction using advanced rig technologies and reduction and recycling through use of treated or recycled water dust suppression, civil works and drilling activities (Santos, 2017). Water use and wastage will be minimised, where possible. The use of recycled water for hydraulic fracturing will assist to reduce the volume of water needed for hydraulic fracturing.

When Santos moves from the exploration phase to development, 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 (Santos, 2017).

7.5 Wastewater treatment and waste management

Without adequate management controls in place, waste water produced during unconventional gas activities may pose a risk to surface water and shallow ground water resources, and requires careful and appropriate management. Waste water management is an issue common to conventional oil and gas extraction and other forms of resources and industrial activity, so many of the same principles and practices apply, although there are some features of waste water specific to hydraulic fracturing and deep shale gas wells.

7.5.1 Activity

In unconventional gas extraction, waste water is generated during drilling (as drilling “mud”) and particularly during the “flowback” period following hydraulic fracturing

At the surface, waste water is either stored in temporary storage tanks or ponds, or is transported by pipeline to a waste water treatment facility.

Without adequate management controls, there is potential for accidental releases, leaks or spills due to pond or pipeline failure. Potential incidents are summarised in (ACOLA, 2013) and include:

- Spillage, overflow or water ingress or leaching from cuttings/mud pits;
- Spillage of flowback fluids during transfer to storage;
- Loss of containment of stored flowback fluids;
- Spillage of flowback fluid during transfer from storage to tankers for transport; and
- Spillage of flowback fluid during transport to waste water treatment works (Hawke, 2014).

7.5.2 Scientific evidence

The IAH(NT) (IAH, 2014) submission notes that safe containment, treatment and disposal of waste water at the surface is particularly difficult in the monsoonal north; and that one problem with trying to manage containment dams in high rainfall areas is that the NT has no dam safety regulations. The IAH(NT) submission recommends that waste water storage should be in lined ponds with a flood immunity of 1,000 years (Hawke, 2014).

Shale gas differs significantly from coal seam gas, in that the volume of produced water from shale gas is much lower and of poorer quality than from CSG production. Therefore the (high-profile) water management issues associated with CSG production do not necessarily apply to shale gas, but neither are some of the reuse and recycling options developed for CSG (such as beneficial use priorities under the *Queensland Coal Seam Gas Water Management Policy 2012*) applicable to shale gas (Hawke, 2014).

Flowback water from unconventional gas wells cannot generally be treated by typical municipal waste water treatment plants due to high salinity and the possible presence of NORMs (CCA, 2014). Other treatment methods that may allow treated water to be discharged have high costs (although these have been predicted to decline as demand increases and technology improves) and hence deep-well injection has been the preferred disposal option in North America when geology is suitable.

There are risks with deep disposal of waste water including ground water impact and induced seismicity, which can be mitigated by a detailed understanding of the stratigraphy and hydraulic properties of the formations used, and low injection pressures and rates (CCA, 2014), (Hawke, 2014)

7.5.3 Santos and industry mitigation

Santos uses a number of practices to minimise risk from waste water. Flow-back pits are lined with UV-stabilised high-density polyethylene liners, and earthen bunds are built around flow-back pits to prevent surface water ingress. During operations, tanks and ponds are inspected at least daily for potential breaches or leaks and repaired as required. A minimum of 300mm freeboard in tanks and pits is maintained to prevent overflow associated with flooding or surface water ingress. Emergency shutdown systems are installed on equipment to prevent uncontrolled release of flowback water or other chemicals, and there is routine inspection of flow-back lines, connections, high pressure equipment and trip systems.

Where heavy rainfall or floodwaters pose a risk, produced fluids are removed from pits and transferred to tanks or facilities not subject to flood risk. During Santos' exploration operations, fluids are evaporated in lined pond systems Figure 43. Licenced waste management contractors are then used to transport waste material to approved waste management facilities (such as in Adelaide) for disposal (Santos, 2013), (Hawke, 2014).

As indicated by Hawke review (2014), Santos are undertaking stage-wise improvements towards replacement of lined pits with tanks, including specially designed flowback tanks and pit-less flowback operations; and increasing the extent of recycling of flowback fluid in hydraulic fracturing operations (Hawke, 2014).

Assessment and management of risks are undertaken by reviewing the existing site environment, assessing hazards to determine which chemicals are of most concern, assessing exposure pathways and then characterising and managing the risks appropriately

Monitoring will be undertaken to determine baseline conditions prior to hydraulic fracturing and waster generation and storage, then during and after the fracturing event through to after the well has been decommissioned (IESC, 2014).

Santos proposes that industry should work together to develop a common understanding of "leading practice" for the management of waste water from unconventional gas activities in the NT. This may include developing guidance for preferred approaches in different biomes and climate regimes including, for example, risk management approaches, practices and engineering designs for extreme rainfall or flood events.

Figure 43 Above ground storage pond used for stimulation make-up water storage and flow back water storage in the Cooper Basin. Source: Santos, 2013.

Pending the outcomes of this Inquiry, Santos is supportive of legislative or regulatory amendment that enables best practice

- *Baseline assessment and post stimulation monitoring of water bores located within a 2 km radial distance of a well.*
- *Disclosure of chemical additives and chemical risk assessments for hydraulic fracturing chemicals to Government.*
- *Government disclosure of chemical additives to the public*
- *Best practice code such as the Code of Practice for Constructing and Abandoning of Petroleum Wells and Associated Bores in Queensland or Guidance and Specifications provided by American Petroleum Institute.*

7.6 Hydraulic stimulation chemicals

Hydraulic fracturing fluids are formulated to create and extend the fracture, and transport and place the proppant in the fractures (Montgomery, 2013; (Spellman, 2012), (Gupta & Valko, 2007)

Hydraulic fracturing fluid generally consists of three parts: base fluid (the largest constituent by volume), additives and proppant. Base fluid (water) and proppant (sand) make up 99% of the hydraulic fracturing fluid, with additives making up the remaining 1% (CSIRO, 2012). A typical hydraulic fracturing fluid includes between three and twelve additive chemicals depending on the characteristics of the water and the shale being fractured. Each component serves a specific, engineered purpose (ACOLA, 2013), including the following purposes:

- Viscosity: gelling agents are added to the water to provide viscosity to enable the proppant material such as sand or ceramic beads to be transported down the well and into the created fractures.
- Friction reduction: to reduce the force required to pump the fluid, friction reducers are added, making the fluid more ‘slippery’ and easier to pump at the high pressures and rates required to create the fracture network.
- Biocide: biocides or disinfectants are added to ensure that no microbes or organisms present in the water will destroy the gelling agents and also to ensure they will not enter and contaminate the reservoir.
- Scale and corrosion: scale and corrosion inhibitors are added to prevent deposition of mineral scales and to prevent corrosion of the steel casing or tubing.
- Surface tension: surfactants or surface tension modifiers are added to assist the back flow of fluids from the formation (Santos, 2017).

7.6.1 Activity

Once the well is drilled, casing cemented and perforations made, the well is connected with the target zone and is regarded as completed. The next step is the injection of fluids and particles (proppant) into the well to initiate fracturing (IESC, 2014).

The aim is to design a stimulation that will stay in the “pay zone”, develop maximum producing formation contact and achieve maximum flow of hydrocarbons and minimum flow of produced water. The hydraulic fracturing fluid design specifies volume, rate and other factors to achieve the targeted fracture height, width, length and complexity (ACOLA, 2013).

Chemical mixing

Chemical mixing is an engineered process that requires the use of specialised equipment and a range of different additives to produce the fluid that is injected into a well to fracture the formation. This fluid, the hydraulic fracturing fluid, generally consists of a base fluid (typically water), a proppant (typically sand), and additives (chemicals), although there is no standard or single composition of hydraulic fracturing fluid used. The number, type, and amount of chemicals used to create the hydraulic fracturing fluid vary from well to well based on site- and operator-specific factors. Without adequate controls in place, spills may occur during in the chemical mixing process.

Injection of hydraulic fracturing fluid under pressure

The first phase is the cleaning and preparation of the well. The fluid used in this phase is often referred to as the pre-pad fluid, pre-pad volume, or spearhead. Acid is typically the first chemical introduced. Acid, with a concentration of 3% to 28% (by volume, typically hydrochloric acid, HCl), is used to clean any cement left inside the well from cementing the casing and dissolve any pieces of rock that may remain in the well that could block the perforations.1 Acid is typically pumped directly from acid storage tanks or tanker trucks, without being mixed with other additives. The first, or pre-pad, phase may also involve mixing and injection of additional chemicals to facilitate the flow of fracturing fluid introduced in the next phase of the process. These additives may include biocides, corrosion inhibitors, friction reducers, and scale inhibitors (Carter, Hammack, & Hakala, 2013), (King G. E., 2012), (Knappe & Fireline, 2012), (Spellman, 2012), (Arthur, Bohm, & Layne, 2008).

The chemicals are first mixed into the fluid via a chemical addition trailer and sand (or ceramic particles) is then added via a blender before going to the high pressure pumps and down the well. Pumping of a fracture stage may last between 20 minutes to 4 hours, depending on the design. (ACOLA, 2013)

In the second phase, a hydraulic fracturing fluid, typically referred to as the pad or pad volume, is mixed, blended, and pumped down the well under high pressure to create fractures in the formation. The pad is a mixture of base fluid, typically water, and additives and is designed to create, elongate, and enlarge fractures in the targeted geologic formation when injected under high pressure (Gupta & Valko, 2007) (see Section 6.3 for additional information on fracture growth following injection). A typical pad consists of, at minimum, a mixture of water and friction reducer.

A typical pad consists of, at minimum, a mixture of water and friction reducer. Other additives (see (US EPA, 2015)and Table 5-1) may be used to facilitate flow and kill bacteria (Carter, Hammack, & Hakala, 2013) (King G. E., 2012), , (Spellman, 2012), (Arthur, Bohm, & Layne, 2008)). The pad is pumped into the formation through perforations or sliding sleeves in the well casing.

In the third phase, proppant, typically sand, is mixed into the hydraulic fracturing fluid. The proppant volume, as a proportion of the injected fluid, is increased gradually until the desired concentration in the fractures is achieved. Gelling agents, if used, are also mixed with the proppant and base fluid in this phase to increase the viscosity to help carry the proppant. Additional chemicals may be added to gelled fluids, initially to maintain viscosity and later to break down the gel and decrease viscosity, so the hydraulic fracturing fluid can more readily flow back out of the formation and through the well to facilitate production from the fractured formation (Carter, Hammack, & Hakala, 2013) (King G. E., 2012), (Knappe & Fireline, 2012), (Spellman, 2012), (Arthur, Bohm, & Layne, 2008)).

A final flush or clean-up phase may be conducted after the stage is fractured, with the primary purpose of maximizing well productivity. The flush is a mixture of water and additives that work to aid the placement of the proppant, clean out the chemicals injected in previous phases, and prevent microbial growth in the fractures (Knappe & Fireline, 2012), (Fink, 2003).

The second, third, and fourth phases are repeated multiple times in a well with multi-stage hydraulic fracturing.

As part of the hydraulic stimulation process, the sand or proppant material remains in the low-permeability rock while approximately 30–70% of the fluid is recovered to surface along with hydrocarbons during the wellbore clean-up phase. These fluids are separated from the hydrocarbons, with the wastewater being captured in lined tanks or ponds for disposal via approved means. Any fluid that is not flowed back and recovered stays in the hydrocarbon bearing zone and does not migrate to overlying aquifers.

7.6.2 Scientific evidence

There have been several comprehensive hydraulic fracturing risk assessments completed by the petroleum industry that have been considered and accepted by governments as part of multiple state and federal ministerial project approval processes. These assessments consider real world chemical use and all aspects of risk and risk mitigation and collectively cover over 200 chemicals. (APPEA, 2016). Claims that hydraulic fracturing chemicals have not been assessed for their long-term impacts on the environment and human health are misleading as the National Industrial Chemicals Notification and Assessment Scheme (NICNAS) has not assessed 85% of the 40,000 industrial chemicals used by other industries in Australia (APPEA, 2016).

The US Department of Energy has published a table of additive type, main chemical compounds and common use for hydraulic fracturing (US DOE, 2009). In addition, some service companies have disclosed the nature of hydraulic fracturing fluids – see for example Halliburton's disclosure for the United States, Europe and Australia (Halliburton, 2013). (ACOLA, 2013).

In Australia, the industry discloses chemical additives to government and to landholders as required by law — for example this is a legal requirement in Queensland.

Details of the chemicals used are also available on company and government websites. For example: https://www.ehp.qld.gov.au/management/non-mining/fraccing-chemicals.html

In Queensland, Santos conducts a comprehensive risk assessment on the chemicals used in hydraulic fracturing. The assessment is reviewed by multiple state and federal agencies including the Federal Department of the Environment and the Independent Expert Scientific Committee as part of the Environmental Impact Statement process. The Santos GLNG Upstream Hydraulic Fracturing Risk Assessment has been publically available on the Santos website since 2011.

A scope and methodology to undertake such chemical risk assessments has been provided as available in Appendix B.

Chemical additives can also only pose a risk to human health or the environment if there is a valid or potentially valid exposure pathway. A potential range of exposure pathways and potential management options are discussed below:

- **Fracture Propagation Pathway** - As discussed the risk of fracture propagation surface or to the shallow Cambrian limestone is considered remote and unlikely. This is because of the present day stress regime of the Beetaloo Basin and hard overburden layers resulting in horizontal fracture propagation. The risk is further reduced by the large separation distances between the target shales and the shallow aquifer.
- **Well Casing Migration Pathway -** The risk of a migration pathway to the surface or the shallow Cambrian aquifer is managed through the well integrity process = design, procure, test, construct, verify and then ongoing performance monitoring over the lifecycle. With the implementation of a well integrity program the risk of migration to receptors or the shallow Tindal aquifer is considered remote and unlikely.
- **Fault Migration Pathway** – As discussed, the presence of faults at reservoir depth is limited. Any increase in fracture height increase due to faults in limited. This is because the present day stress regime for the Beetaloo Basin any fault is considered to be sealing. Based on this the risk of faults acting as migration pathways to surface or shallow aquifers would considered remote and unlikely.
- **Surface releases Pathway (spills or leaks)** - The risk of chemical additive spills or leaks to the ephemeral watercourses and / or soils (including subsequent migration to shallow groundwater or run-off to ephemeral watercourses) is managed throughout the transport, storage, mixing, flowback and re-use / disposal stages.
- **Trespasser** - The risk of exposure from a trespasser is manages through:
  - Remote setting – the opportunity for access and therefore exposure is limited
  - Limited opportunity - Chemical additives are only on the lease pad for a few days to weeks over its 20-30 year lift - the opportunity access and therefore exposure is limited
  - Limited opportunity - For the period the additives are present, the operations are manned - the opportunity access and therefore exposure is limited
  - Access deterred to limit the opportunity - Well pads and additive storages are sign posted and labelled according to legislative requirements – this is to deter access and therefore the potential for exposure.

Semi-quantitative and quantitative human health and ecological risk assessments have been performed for a range of exposure scenarios. These assessments are supported with empirical data and direct toxicity assessments. These risk assessments demonstrate that the potential for adverse impacts to human health are limited.

New Chemicals: Chemical rating systems have been developed that 'score' the chemical mix for environmental, toxicological and physical hazards (Jordan, et al., 2010). This has led to the replacement of chemicals by mechanical options and the utilisation of food grade chemicals, biodegradable biocides, and the use of lower volumes of chemicals.

BTEX compounds have been particularly controversial given threat they have been linked to serious health issues. However, the use of BTEX chemicals in hydraulic fracturing has been banned in Queensland, NSW, Western Australia and NT (IESC, 2014).

Monitoring impacts resulting from hydraulic fracturing should be undertaken to determine a baseline prior to fracturing then during and after the fracturing event through to after the well has been decommissioned (IESC, 2014).

Baseline groundwater monitoring is an important step for demonstrating that groundwater quality and quantity remain unaffected by Santos' activities. Prior to hydraulic stimulation, an assessment of groundwater conditions provides a benchmark against which any future variations can be compared. Data obtained can include a record of a bore's groundwater level, water quality and usage, and provide information on bore construction. This assessment also confirms the location and status of existing bores and groundwater use within the vicinity of operations.

The chemicals used in hydraulic stimulation, in the quantities and methodologies employed, do not pose an unacceptable risk to human health or the environment. Extensive quantitative human health and ecological risk assessments have been undertaken for developments in Queensland. These chemicals and quantitative risk assessments have been reviewed or assessed by the relevant government agencies and have had requisite Material Safety Data Sheets (MSDS) prepared. This information is publically available on Santos' website:

- Chemical Risk Assessment - Environmental Management - It can be found at coal seam gas fields / GFD Project – Water Quality Management Plan
- Compendium of Assessed Fluid Systems.

All chemicals are approved for use by the Australian Government (Department of Health) and listed on the Australian Inventory of Chemical Substances (AICS) (maintained under the National Industrial Chemicals Notification and Assessment Scheme (NICNAS)).

All chemicals used within Santos' petroleum activities are provided to the NT Department of Mines and Energy (DME) as part of the Environment Plan approval process. These chemicals, and their associated MSDS, are made publicly available on the DME website.

These chemicals are used for many different household functions and are not specific to hydraulic stimulation. Common uses include toothpaste, baked goods, ice cream, food additives, detergents, cosmetics and soap.

7.6.3 Santos and industry mitigation

Pending the outcomes of this Scientific Inquiry into Hydraulic Fracturing - Santos would be supportive of legislative or regulatory amendment to enable best practice well construction and decommissioning. This may include the Code of Practice for Constructing and Abandoning Petroleum and Associated Bores in Queensland or Guidance and Specifications provided by American Petroleum Institute.

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.

Chemical additives used in hydraulic fracturing fluids are required to be notified and assessed by National Industrial Chemicals Notification and Assessment Scheme (NICNAS), and listed on the Australian Inventory of Chemical Substances (AICS).

- Chemical and Hydraulic Fracturing Risk Assessments have been performed for the Santos GLNG Project
    - These risk assessments have been publically available and updated since 2011 and provide chemical disclosure

- These chemical risk assessments are based on best practice Australian and International guidance, methodologies and assessment tools.
- The risk assessments assess the persistence, bioaccumulation and toxicity of individual chemicals, geogenic compounds in flowback and the total fluid mixture.
- The assessment covers the full lifecycle – transport, storage, mixing, injecting, flowback, reuse, recycling and disposal.
- The chemical risk assessments have undergone various phases of reviewed and / or assessment by State and Commonwealth Governments.
- 792 baseline groundwater bores assessments were completed for the GLNG project
- Further baseline bore assessments have been completed for groundwater bores located within a 2km radius of a stimulation event (13 bores assessed since 2011).

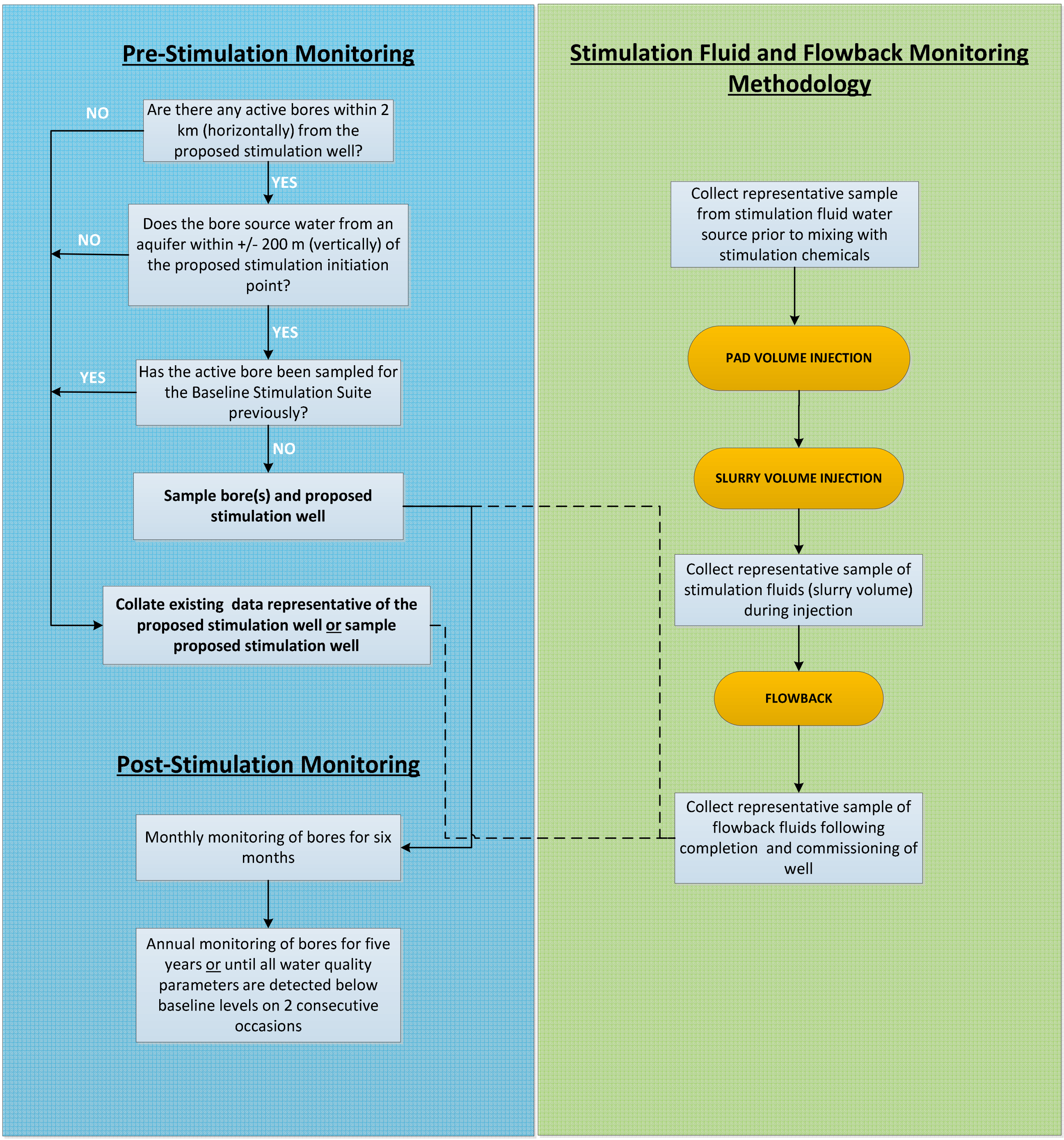
Santos has provided a proposed scope and methodology for chemical risk assessments based on this best practice guidance as part of this submission. This can be found in **Error! Reference source not found.**. Santos is aware that the Commonwealth Government is developing best practice national guidance for chemical risk assessments relating to hydraulic fracturing fluids.

Monitoring

Landholders' bores that are active and proximal to a hydrocarbon well will be included within the baseline assessment program. Santos will arrange for water quality testing of the bore water before and after hydraulic stimulation. These results can be made available to the landowners to provide confidence that their assets are protected and that risk control measures are successful. An overview of an indicative monitoring program is provided in Figure 44.

Pending the outcomes of this Inquiry, Santos would be supporting of legislative or regulatory amendment requiring baseline assessment and post stimulation monitoring of water bores located within a 2km radial distance of a well.

Figure 44 Stimulation monitoring overview



CSIRO research in 2014 on 43 coal seam gas production wells in Queensland identified a leakage emission rate of 0.02% of production.

Given that there are approximately 2 million cattle in the NT, then over 71,000 of these same production wells would be required to equal the same rate of methane emissions to the atmosphere as emitted by the cattle.

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

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

7.7 Fugitive emissions

Fugitive emissions refer to unintended releases of gas from industry operations. In oil and gas, this includes methane released from exploration drilling, production testing and well completion, and gas production activities (APPEA). Fugitive emissions can occur from equipment leaks, venting and operation of gas-powered pneumatic devices, and exhaust from gas-fuelled engines used to power water pumps. Other human induced methane emissions occur through grazing of domestic stock, agricultural production and from landfills (Barrett, 2014).

Methane is also released naturally, seeping from coal seams or other organic rich rocks or from biological processes occurring in wetlands, swamps, rivers and dams (CSIRO, 2015). Natural connectivity along faults, cleavages, and subsurface strata and the atmosphere can result in the seepage of 'background' emissions of methane to the atmosphere (GISERA, 2015).

Natural gas seeps predate gas industry operations. As early as 1889, people drilling for water are recorded to have encountered naturally occurring gas seeps and accumulations – one of these was tapped early last century to light the streets of Roma (GasFields Commission Queensland, 2015).

In the Greater Beetaloo Basin shallow gas accumulations may be encountered in future operations (refer to Section 5.1.3). Moreover elevated atmospheric methane concentrations may occur where gas bearing carrier beds outcrop or subcrop along the basin margins. For example, in Marmbulligan-1 drilled in EP161, gas was encountered in middle Velkerri Formation shales just a few hundred metres below ground surface (refer to Section 4.2.1). 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.

All hydrocarbons are flammable. Methane at ambient temperatures is only flammable when the gas concentration is 50,000 parts per million (ppm) to 150,000 ppm or between 5% and 15% of the total gas/air mixture (GasFields Commission Queensland, 2015). Fugitive emissions are in such low concentrations that the risk of fire is extremely low (APPEA). Nevertheless, the industry takes significant steps to reduce the risk of any fires from petroleum infrastructure.

7.7.1 Activity

Hydraulic fracturing

During hydraulic fracturing, materials that typically consist of water, sand and additives, are injected at high pressure into low-permeability formations. The injection of the hydraulic fracturing fluids creates channels for flow in the formations, allowing methane and other hydrocarbon gases and liquids in the formation to migrate to the production well.

After drilling and fracturing, the well is "completed" to make the well ready for continuous natural gas production. During well completion, the well is cleaned of sand and liquid, after which the well is placed into production. The recovery of these fluids is referred to as a flowback, and gas, including methane, can be dissolved or entrained in the flowback liquids (Allen, 2013).

Some of the methane in the liquids can be sent to sales or emission control devices, but some can be emitted. Over recent decades, natural gas production processes have changed significantly to incorporate operational practices that have equipment in place to reduce methane emissions (losses).

Drilling and other sources

The potential for fugitive releases of methane during drilling is greater if there is free gas within the reservoir (although wells are drilled with blow-out preventers which avoid uncontrolled gas release during drilling). Typically in its virgin state, there is no free gas in an unconventional gas reservoir as the gas is stored within pores and fractures of the original source rock, or by adsorption under pressure of geological formation. Where the well pressure is less than reservoir pressure, gas may accumulate within wellbores and then be released (limited by the wellbore volume).

Other sources of fugitive emissions may comprise equipment leaks, venting, pneumatic device operation and engine exhaust.

7.7.2 Scientific evidence

Typically, greenhouse gas emission analyses have generally been based on either engineering estimates of emissions or measurements made 100 m to a kilometre downwind of the well site. Many measurements in the public domain are outdated by the evolving technology and practices available at that time.

It has been argued that large amounts of gas are directly vented to atmosphere during flow (Howarth, 2011); with some specific assumptions about global warming potential of gas, it has been suggested that the impact of shale gas might be greater than that of coal on a lifetime basis (Howarth, 2011).

The claims are refuted by research undertaken by the CSIRO in 2014 on 43 coal seam gas production wells in Queensland that identified a leakage mean emission rate of 0.02% of production. While it is acknowledged that this leakage rate is for the production well and does not include other supporting infrastructure it is still important to put this leakage in perspective - Given that there are approximately 2 million cattle in the NT, then approximately 71,000 of these same production wells would be required to equal the same rate of methane emissions to the atmosphere as emitted by 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 inform the Australian magnitude of these emissions and to inform managed controls, CSIRO scientists, through the Gas Industry Social & Environmental Research Alliance (GISERA) are undertaking further research into lifecycle methane emissions in Australia including understanding the natural or background emissions of methane. This research will include all activities and infrastructure.

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

Cleaner completions

Along with simply venting gas produced during the completion of shale gas wells, two additional techniques are widely used to handle these potential emissions: gas flaring and reduced emission completions. The use of flaring and reduced emission completions reduce the levels of actual methane emissions from shale well completion operations to about 50 Mg CH_4 per well (O'Sullivan, 2012), a release substantially lower than several widely quoted estimates for venting (data from 4000 horizontal shale gas wells that reported emission estimates of 228 Mg CH_4 per well) (O'Sullivan, 2012).

A robust and comprehensive study undertaken by Dr David Allen reports direct measurements of methane emissions at 190 onshore natural gas sites in the US incorporating operational practices that have been adopted or become more prevalent since the 1990s (Allen, 2013). Emissions including 150 production sites, 27 well completion flowbacks (five of the flowbacks were in the Appalachian region), 9 well unloads and 4 workovers.

"The way in which wells are drilled and brought into production has been evolving," said David Allen, professor of chemical engineering at UT's Cockrell School of Engineering and principal investigator for the study. "The overall goal was to measure methane emissions during production at a large number of recently developed sites, and to assess the national implications for methane emissions. The team performed the first-ever direct measurements of methane emissions from some of these sources."

For well completion flowbacks, which clear fractured wells of liquid to allow gas production, methane emissions ranged from 0.01 Mg to 17 Mg (mean = 1.7 Mg; 95% confidence bounds of 0.67–3.3 Mg), compared with an average of 81 Mg per event in the 2011 EPA national emission inventory from April 2013. The measurements indicate that well completion emissions are lower than previously estimated.

The completions with the lowest emissions were those in which the flowback from the well was sent immediately, at the start of the completion, to a separator, and all of the gases from the separator were sent to sales. The only emissions from these completions were from methane dissolved in liquids (mostly water) sent from the separator to a vented tank.

This study found that the majority of hydraulically fractured well completions, which were sampled during study, had equipment in place that reduces methane emissions by 99 percent. Because of this equipment, methane emissions from well completions are 97 percent lower than calendar year 2011 national emission estimates, released by the Environmental Protection Agency (EPA) in April 2013 indicating the US EPA emission factors from the 1990s may not reflect current practices.

In this work, net or measured emissions for the total of all 27 completions are 98% less than potential emissions. This large difference between the net emissions measured in this work and the net emissions estimated in the national inventory is due to several factors. First, consistent with emerging regulatory requirements (21) and improved operating practices, 67% of the wells sent methane to sales or control devices. Second, for those wells with methane capture or control, 99% of the potential emissions were captured or controlled.

Fugitives monitoring

The potential migration pathway for gas to the surface / atmosphere via the outside of the production case of the well is managed through the well integrity process of design, procure, test, construct, verify and then ongoing performance monitoring over the lifecycle.

Leakage from surface infrastructure is easily monitored using specialist monitoring cameras. Any leaks can be readily identified and then addressed.

In a report prepared for the Department of the Environment by the CSIRO (CSIRO, 2014), emission rates detected “were very low, especially when compared to the volume of gas produced from the wells,” and “were very much lower than those that have been reported for US unconventional gas production.” No evidence of leakage of methane around the outside of well casings was found at any of the wells sampled.

There is a large spectrum of scientific methodologies and technologies that exist to measure baseline and post-development flux (GISERA, 2015) (NSW EPA, 2014) (Day, Connell, Etheridge, Norgate, & N, 2012) (Day, et al., 2013).

CSIRO scientists, through the Gas Industry Social & Environmental Research Alliance (GISERA), are undertaking further research into methane emissions in Australia including understanding the natural or background emissions of methane that come from seeps in the ground. This research aims to identify background sources of methane and determine the best detection and measurement methods (NSW EPA, 2014).

7.7.3 Santos and industry mitigation

Santos has a strong track record of working cooperatively with government, industry and the community to address greenhouse gas emissions with specific focus on addressing energy efficiency, the transition to lower emission technologies and reporting transparency.

Regulatory approvals and compliance

As part of the approvals process, proponents are typically required to prepare a detailed emissions inventory and undertake comprehensive assessment of potential impacts that demonstrates compliance with performance criteria that protect public health, amenity and environmental values and commitments to energy efficiency.

Santos and other proponents are required to prepare comprehensive assessments of greenhouse gas emissions, including fugitive emissions, in accordance with the principles outlined in the Greenhouse Gas Protocol (World Resources Institute, 2005) and methodologies described under the *National Greenhouse and Energy Reporting Act 2007* (Cth) (NGER Act) and NGER Determination.

An example greenhouse gas assessment is available in the detailed Environmental Impact Statement (EIS) for the Narrabri Gas Project, which was prepared and submitted to the Government in February 2017, and is currently being assessed by the NSW Government on behalf of the Commonwealth under the assessment bilateral agreement.

Monitoring and improvement

Implementation of baseline monitoring programs will ensure good understanding of natural methane in the prospective area and surrounds. If baseline data is not collected prior to hydraulic fracturing and methane is detected in groundwater afterwards, it can be difficult to determine whether it is the result of hydraulic fracturing (The Royal Society and Royal Academy of Engineering, 2012).

Santos is in the planning phase of a baseline methane monitoring assessment in the Beetaloo Basin. It is anticipated that this will be performed by CSIRO scientists.

Under the NGER Act, annual reporting for greenhouse gas emissions, energy production and energy consumption must be performed by the proponent. Measurement systems will be incorporated into the design to comply with *NGER Act* requirements. Greenhouse gas emissions will be reported and independently assured on an annual basis in accordance with the *NGER Act.*

Additionally, GISERA is currently undertaking assessments for regional methane emissions in NSW CSG basins. The project will identify and quantify methane emissions such as coal seam gas infrastructure, feedlots, coal mining and legacy bore holes in the Pilliga region (GISERA, 2016).

Management framework

As a global stakeholder in the energy business we recognise that one of our key social and environmental responsibilities is to pursue strategies that address the issue of climate change.

At the highest level, Santos' Climate Change Policy sets out its vision and commitments to achieve this vision. These policy commitments underpin Santos' approach to greenhouse gas emissions management, which is governed through corporate management standards.

In accordance with its Climate Change Policy, Santos will:

- Continue to reduce the carbon intensity of its products by focusing on energy efficiency and technology development.
- Use energy more efficiently by identifying opportunities to implement energy efficiency projects and report their progress.
- Examine the commercial development of low emission technologies, including storage solutions, which will contribute towards long-term emission reduction targets.
- Pursue no flaring or venting of associated gas, unless there are no feasible alternatives.
- Continue to publicly disclose its greenhouse gas emissions profile and carefully examine forecast emissions.
- Understand, manage and monitor climate change risk and develop appropriate adaptation strategies for its business.
- Inform employees about its commitment to climate change and ensure climate change initiatives continue to be implemented.
- Report progress against these commitments to the Board of Santos.

These policy commitments underpin Santos' approach to greenhouse gas emissions management, which is governed through a suite of corporate standards, guidelines and manuals.

Each year, Santos’ greenhouse gas emission reports are assured by an independent third party auditor and reported publicly via Santos’ sustainability reports and to the National Greenhouse and Energy Reporting authority.

Progress against Santos’ Climate Change Policy is reported quarterly to the Santos Environment, Health, Safety and Sustainability Committee of the Board.

7.8 Construction noise, diesel emissions and dust

Without adequate management controls in place, noise and air emissions such as dust and products of fuel combustion (i.e. exhaust) have the potential to impact local amenity and public health.

7.8.1 Activity

Hydraulic fracturing involves the mobilisation and operation of heavy and light vehicles and stationary diesel-fuelled plant and equipment (e.g. high pressure pumps). Particularly during construction, these activities generate noise and air emissions; however these activities and corresponding amenity impacts are not ongoing at well leases such as during operational phase.

7.8.2 Scientific evidence

The currently available evidence (EnRisk, 2016) indicates that the potential risks to public health from exposure to the emissions associated with shale gas extraction are low if the operations properly run and regulated. When potential risks have been identified in the literature, the reported problems are typically a result of operational failure and a poor regulatory environment. Therefore, good on-site management and appropriate regulation of all aspects including exploratory drilling, use and storage of hydraulic fracturing fluid, and post-operations decommissioning are essential to minimise the risk to the environment and public health (Public Health England, 2013).

Noise

Noise is a potential nuisance impacts associated with unconventional gas operations that may affect human health and/or pose an ecological risk to sensitive wildlife. Hydraulic fracturing and drilling noise levels can exceed 64 dB at 75 m from the site and an average 40 dB at 1.5 km away (NSIRP, 2011). Noise predictions will inform landholder discussions and inform location selection, engineering and management controls to mitigate potential impacts to as low as reasonably practical.

Many of the impacts such as noise are of short term duration while specific types of activities are being undertaken (such as drilling or hydraulic fracturing). Once a well enters production and is connected to an underground pipeline gas gathering network, many of the localised impacts such as noise and vehicular traffic are greatly reduced or eliminated entirely (Parliament of Victoria, 2015).

Drilling an unconventional gas well may take 4-5 weeks continuous activity, and several months where multiple wells are drilled and fractured on a single pad. Noise impacts are likely to be of most concern where well development is close to human settlement. However for most operations it is a standard requirement set out in industry codes of practice (e.g. Queensland or NSW examples) that effective sound suppression is undertaken (ACOLA, 2013).

Dust and diesel emissions

There may be a risk of emissions from plant and equipment, such as diesel fumes from drilling equipment and pumps and from off-site increases in road traffic. Land disturbance for new surface infrastructure or access roads and vehicle/equipment movement/operations are potentially sources of dust, particularly in high wind conditions.

GISERA and CSIRO have undertaken a number of air quality assessments to determine the impact of gas activities on air quality. GISERA is currently undertaking ambient air quality observations and modelling in the Surat Basin, Queensland. The model will be used to explore the degree to which different emission sources in the Surat Basin contribute to the levels of air pollution. The model includes a variety of natural and man-made emission sources including the gas industry, power stations, mines, livestock production, motor vehicles, bushfires and vegetation (GISERA, 2016). The data is live streamed and is presented on the Queensland Department of Environment and Heritage Protection website (Department of Environment and Heritage Protection, 2017).

The Narrabri Gas Project EIS Air Quality Impact Assessment (Air Environment Consulting, 2016) provides a comprehensive example of the analysis and assessment undertaken to identify, understand and mitigate potential nuisance impacts on ambient air.

Other nuisance impacts may include light pollution, as well development generally continues 24 hours per day; increased vehicle traffic, often including on public rural roads; odours from various products used during drilling and fracturing; and reduced visual amenity (CCA, 2014), (Hawke, 2014).

7.8.3 Santos and industry mitigation

Santos prospective areas are located in remote and rural areas under pastoral lease – for Santos shale prospect this is limited to two pastoral holdings. Given the remote rural setting of the Beetaloo Basin and that no townships are located in proximity to the prospective areas; the amenity and public health risks to residential receptors and urban environments are considered remote and unlikely.

Impact assessments

Public health and amenity impact assessments are typically developed as part of the approvals process. As part of Santos' Narrabri Environmental Impact Statement (EIS), a Health Impact Assessment (which assessed the potential health impacts from air) was developed (GHD 2016).

Air quality impact assessment are typically developed as part of the approvals process. As part of Santos' Narrabri Environmental Impact Statement (EIS), an Air Quality Impact Assessment was developed (Air Environment Consulting, 2016). These assessments as part of the EIS demonstrate compliance against performance criteria to protect public health. Relevant approvals and licences will be obtained by Santos.

Noise and vibration impact assessments are typically developed as part of approvals processes. As part of Santos' Narrabri Environmental Impact Statement (EIS), a Noise and Vibration Assessment was developed (GHD 2016).

These assessments model potential impacts and apply mitigation to comply with accepted criteria. Should approval be granted, the activity will be designed through this performance criterion to manage the risks associated with public health and amenity. Previous management measures undertaken by Santos have included are discussed below.

Environmental management plans

The activity will be designed through this performance criterion to manage the risks associated with public health – these measures are presented in an EMP. Previous management measures undertaken by Santos have included are discussed below. In the NT, noise is one of the environmental impacts and risks required to be addressed in the operator's Environment Plan required for project approval (refer Section 6.0).

Engineering controls

Consultation with landholders about proposed operations may initiate procedures to mitigate noise impacts. Work health and safety procedures include managing the noise exposure of personnel on site.

Noise mitigation measures include:

- Activity locations will be determined in consultation with the landowner so as to ensure noise levels at residences are low
- Construction works will generally be conducted during daylight hours. Drilling activities are 24 hr operations and landholder notification is given prior to commencement of drilling
- Equipment will be maintained
- Complaints will be responded to in a timely manner.

Dust suppression mitigation measures include:

- Application of water to unsealed road and construction area surfaces used for mobile plant and vehicle traffic
- Application of misting water sprays in areas where earthworks are being conducted.
- Limiting of dump heights by excavation equipment
- Reducing the speed of vehicles on unsealed roads.

Baseline Monitoring

Monitoring impacts resulting from hydraulic fracturing should be undertaken to determine a baseline prior to fracturing then during and after the fracturing event through to after the well has been decommissioned (IESC, 2014). Such examples of baseline monitoring that may be required include water quality monitoring, air quality and methane monitoring, dust monitoring, stimulation monitoring, soils and ecology monitoring.

Landholder and traditional owner consultation is a priority for all Santos activities.

Cooperative agreements with landholder and traditional owner already in place as a result of consultation for exploration.

The NT has existing legislation in place relating to securities for potential environmental liabilities, and existing security calculator and guidance in place for the calculation of the amount of the security.

7.9 Land access, conduct and compensation

Land access, conduct and compensation are subject to extensive consultation and agreement with landholders, traditional owners and government (in the form of royalties and securities).

7.9.1 Activity

As part of seeking approvals to pursue resource development activities (including exploration), Santos prioritises consultation with traditional owners and landholders and confirming acceptable agreements in addition to regulatory approvals.

The surface footprint of hydrocarbon extraction is generally minimal and temporary. Access roads and surface infrastructure such as processing facilities, compressor stations, and some water management facilities are in place for a longer period. These are located and constructed in ongoing consultation with landholders. Access roads are also planned with landholders to accommodate shared use.

7.9.2 Scientific evidence

The NT Government has stakeholder engagement guidelines for land access that state the oil and gas permit holder and the landholder must reach an agreement prior to the start of an exploration program, and the required government approvals will not be granted in the absence of proof of an agreement.

The guideline also provides a dispute resolution process. The parties have 60 days to reach a land access agreement, commencing from the date that the oil and gas permit holder sends a notice of intention to commence negotiations to reach an access agreement to the landholder. If an agreement cannot be reached within 60 days, either party may refer negotiations to the Arbitration Panel to make a determination on the conditions of access.

By agreement, parties can commence arbitration before the expiry of the initial 60 day negotiation period. The Arbitration Panel will comprise the Chief Executives of the relevant NT Government Departments and experienced industry representatives. It will have up to 21 days to make its recommendations.

Once an access agreement has been reached, either by mutual consent of the parties or through a determination by the Arbitration Panel, an exploration program may commence once the requirements are met and after providing 14 days' notice to the landholder. If either party does not agree with the determination of the Arbitration Panel, they retain the right to seek further review through the judicial system. However, this does not affect the approval that has been granted as a result of the arbitration determination or the right of the operator to commence activity. Santos supports this process despite it potentially causing scheduling issues through the addition of up to 95 (or more) days to the time already spent trying to reach an access agreement directly with the landholder (or the landholder's authorised representative).

Santos pays a landholder's legal fees (to an agreed value) to allow for the independent review of a proposed Conduct and Compensation Agreement (CCA).

Strong track record

Santos has successfully coexisted with agriculture for more than 60 years.

To date, Santos has negotiated and executed 29 CCA's with pastoralists across our NT exploration permits, without the need for arbitration or judicial recourse. The Santos approach is modelled on the landholder framework that has been employed in the Cooper Basin (SA-Queensland) over many years (Santos, 2017).

Santos has demonstrated a clear understanding of the needs and challenges of overlapping and adjacent agricultural businesses – not only through those years of co-existence but also as landholders. Several properties owned by Santos in the Fairview, Wallumbilla, Arcadia Valley and Roma fields of Queensland are used to locate infrastructure and run herds of up to 4,500 head of high quality Droughtmaster cattle.

In Queensland, since January 2011, GLNG has secured approximately 1,450 agreements with more than 410 landholders for long-term gas infrastructure alongside their farming businesses. Many hundreds more agreements have been signed for activities such as exploration and pipeline easements.

In addition, GLNG has achieved pleasing results in independent surveys of landholder sentiment conducted by Nielsen Australia. Surveys took place in 2013 and 2014 in areas around Roma, Injune, Arcadia, Taroom, Wandoan and Rolleston. Among the results of the 2014 survey:

- 92% of respondents said they would allow Santos back onto their property. This was the same result from the 2013 survey.
- 94% were satisfied or more satisfied with the relationship than 12 months prior.
- 92% said they had sufficient time to prepare, understand and negotiate a Conduct and Compensation Agreement (CCA).

Notably, 75% of the respondents had construction work taking place on their properties at the time of the survey – the period of highest activity and therefore potential inconvenience for landholders (Santos, 2017).

7.9.3 Santos and industry mitigation

Location and land access

Santos prospective areas are located in remote and rural areas under pastoral lease to foreign landholders – for Santos shale prospect this is limited to two pastoral holdings. Santos works collaboratively with stakeholders to locate and construct surface and sub-surface infrastructure to ensure that current and future uses of land are not negatively impacted.

Given the remote rural setting of the Beetaloo Basin and that no townships are located in proximity to the prospective areas, then the risks to residential receptors and urban environments are considered remote and unlikely.

Pending the outcomes of this Inquiry, Santos would be supporting of legislative or regulatory amendment prohibiting hydraulic fracturing within townships and urban centres plus a 2 km buffer. This was done in Queensland where a township was given a legal definition of a permanent population of more than 200 persons.

Stakeholder engagement

Santos is committed to treating landholders with respect at all times. We have a strong track record of respectful and constructive engagement with landholders. Consultation seeks to ensure the right information is provided in a timely manner and in an appropriate fashion, recognising the busy lives and pressures already placed on landholders. We work through a series of steps encompassing phases of initial meetings and property mapping, negotiating agreements including location of infrastructure, compensation and conditions specific to the property, the construction period, and then ongoing engagement as required (Santos, 2017).

Across the business in 2015, Santos undertook nearly 9,000 discrete interactions with landholders across its Australian operations. This included emails, workshops, briefings, letters, one-on-one meetings, phone calls and SMS messages.

Traditional owners

No on ground activity will commence until all required approvals, consents and any associated conditions have been obtained from the Northern Land Council and all personnel have been fully inducted and are aware of all operational requirements and their specific responsibilities (Santos, 2016).

Santos works compliantly under the provisions of the Native Title Act 1993 (NTA) and the Aboriginal Land Rights (NT) Act with executed and operational exploration agreements in place across EP161, EP162 and EP189. The Agreements ensure traditional owners are engaged and informed throughout the lifecycle of exploration activities (with provision for negotiation of a production agreement) with work programs submitted on an annual basis to the Northern land Council.

Santos activities to date across EP161, EP162 and EP189 have been subject to sacred site certification through the Aboriginal Areas Protection Authority in accordance with the Sacred Sites Act 1989. The conditions of sacred site certification are incorporated into the planning of exploration activities. Santos also promotes industry awareness with Traditional owners and has undertaken site visits to observe exploration activities along with welcome to country ceremonies being undertaken.

Agreements and processes are in place to ensure that all sites of sacred or cultural heritage significance are identified, recorded and avoided during the course of exploration and production activities. In particular, the process for sacred site clearance is provided below:

1. Execute a Co-operation and Exploration agreement in place for the study area (i.e. EP161) with the Northern Land Council. The Northern Land Council will commission an independent anthropological assessment and report on any cultural and sacred sites and values of the area that will be subjected to the proposed activity.
2. The agreement is to cover the life cycle of exploration activities which includes ensuring the traditional owners are consulted and informed on project activities.
3. Santos submits an annual work program to the Northern Land Council. This includes completion of ground and aerial reconnaissance
4. The work program then triggers the requirement to consult on country with the traditional owners regarding exploration activities.
5. The Northern Land Council works with the traditional owners to undertake sacred site clearances of the areas prescribed in the work programs.
6. The sacred site clearance report is then presented to Santos.
7. The contents of the report are than lodged with the Aboriginal Areas Protection Authority (AAPA) who then undertake certification and an issue Authority Certificate for the survey area.
8. Santos then incorporates any of the conditions contained within the certificate into project planning to ensure compliance; i.e. avoidance of exclusion zones (Santos, 2016).

Through this process any identified sacred sites have been avoided and therefore protected from activities.

Compensation

The compensation framework for our NT exploration program is based on the following and meets the requirements of the NT Petroleum Act. Compensation is paid for:

- Loss of land i.e. wells, borrow pits and roads
- Loss of productivity i.e. buffers along roads
- Pipeline construction and rehabilitation
- 2D and 3D seismic survey disturbance
- Livestock losses
- Management time
- Extraordinary disturbances (Santos 2017).

When benchmarked against other states and the SA Petroleum Act, the compensation provisions in the NT Petroleum Act are very similar i.e. compensation based on deprivation/damage to land on a one-off basis – not an annual emolument (or 'annualised' for the period that the disturbance remains on the land) (Santos 2017). It is also consistent 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 (Santos 2017).

The compensation framework for traditional owners is based on a percentage of program cost paid on an annual basis as per the terms of the exploration agreement. Each exploration agreement has provision for the negotiation of a production agreement which ensures traditional owners are compensated for the lifecycle of petroleum activities.

A 2014 PwC analysis identified the oil and gas industry as one of Australia's highest value-adding industries, with every dollar of production generating 70 cents of value-add compared to an average of 49 cents for all other industries.

In SA, Santos' operations were estimated to have contributed around $1,445 million in value added to the state economy in 2014, and around 2,724 full-time jobs to the SA workforce.

The benefits of a successful shale gas development in the NT will be shared. Many of the benefits of shale gas production in the NT will accrue to the NT Government, Indigenous landholders and local communities.

7.10 Economics

7.10.1 Activity

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.

7.10.2 Scientific evidence

A 2014 PwC analysis identified the oil and gas industry as one of Australia's highest value-adding industries, with every dollar of production generating 70 cents of value-add compared to an average of 49 cents for all other industries. The PwC report found that the oil and gas industry's annual contribution to Australia's economic output was expected to more than double from $32 billion in 2012-13 to $67 billion by 2029-30.

There are relevant examples in Queensland, NSW and SA that demonstrate the positive economic impact Santos' oil and gas activities, existing and proposed, have had or could have on the areas in which Santos operate, and beyond. There is no reason to believe that development of a shale gas industry in the NT would not deliver similar significant economic returns to the region and broader community.

Indeed, in August 2015, a Deloitte Access Economics study found that developing a shale gas industry in the NT could drive significant long-term economic growth, creating thousands of new jobs and generating almost $1 billion of government revenue.

SA economic contribution

Santos has explored for oil and gas in the north-east of SA since 1954. Today the Cooper Basin development is Australia's largest onshore resource project, producing sales gas, ethane, crude oil and gas liquids from the basin.

A Deloitte Access Economics Report (2015) into the economic contribution of Santos' SA 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.

As a share of GSP, Santos alone represented 1.5% of the SA economy through both its direct and indirect contribution in 2014. Estimates suggested that Santos, as a single entity, made a larger direct contribution to gross output and GSP than the entire SA wine sector, which made an estimated direct contribution of approximately $1 billion to output in the state and $350 million in value added to GSP in 2013.

In addition to the above, Santos also made significant direct capital expenditure. In 2013 alone, expenditure on exploration and development in SA was estimated to amount to $586 million, growing to $779 million in 2014.

When the activity from Santos' Cooper Basin joint venture partners is incorporated into the modelling, the economic contribution to the SA economy rises to $2,104 million in value added and 3,886 full-time employees in 2014. This is equivalent to a share contribution of 2% to GSP and 0.6% to the state full time equivalent workforce. In recent times, the petroleum sector has faced challenging market conditions, with oil prices having fallen from above $US 100 a barrel to less than $US 40 a barrel.

Cuts to employee headcounts and operating and capital expenditure have occurred in response, along with asset sales and write-downs. But the industry is cyclical, and the Deloitte Access Economics Report (2015) highlights the significant economic contribution oil and gas activities can generate. Even in less buoyant times, operating and capital expenditure continues.

Queensland economic contribution

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 about $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 – discussed below - has been significant.

NSW economic contribution

In NSW, Santos has committed to a Landholder Incentive Fund at 5% of Santos' statutory annual royalty payment (the equivalent to 0.5% of wellhead value) upon *development* of the Narrabri Gas Project (Santos, 2017).

7.10.3 Santos and industry mitigation

Several studies and reports published over the last five years have confirmed that the unconventional gas sector can contribute significantly to prosperity of the nation as a whole and specific regions in particular. In 2015, Deloitte Access Economics (Deloitte) undertook a comprehensive analysis of the potential economic impact of the development of shale and tight gas resources in the NT. This report found that onshore shale and tight gas production has the potential to drive significant economic growth and provide substantial benefits to the NT economy (Deloitte, 2015).

In NSW, detailed economic modelling of Santos' proposed Narrabri gas project indicates it would generate a range of benefits including $3.1 billion of capital investment, direct creation of approximately 1,300 jobs during peak construction, about 200 ongoing jobs during operations, average direct and indirect employment over 25 years of 750 full-time equivalent jobs, an increase in real income in the Narrabri region of $641 million, and the establishment of a Gas Community Benefit Fund that would receive an estimated $100 million through the life of the project.

To examine the economic impacts and benefits of the proposal, an economic impact assessment will be undertaken similar to the Santos' Narrabri Environmental Impact Statement (EIS) Economic Assessment (GHD, 2016) that was developed and will be implemented over the life of the Narrabri project (GHD, 2016).

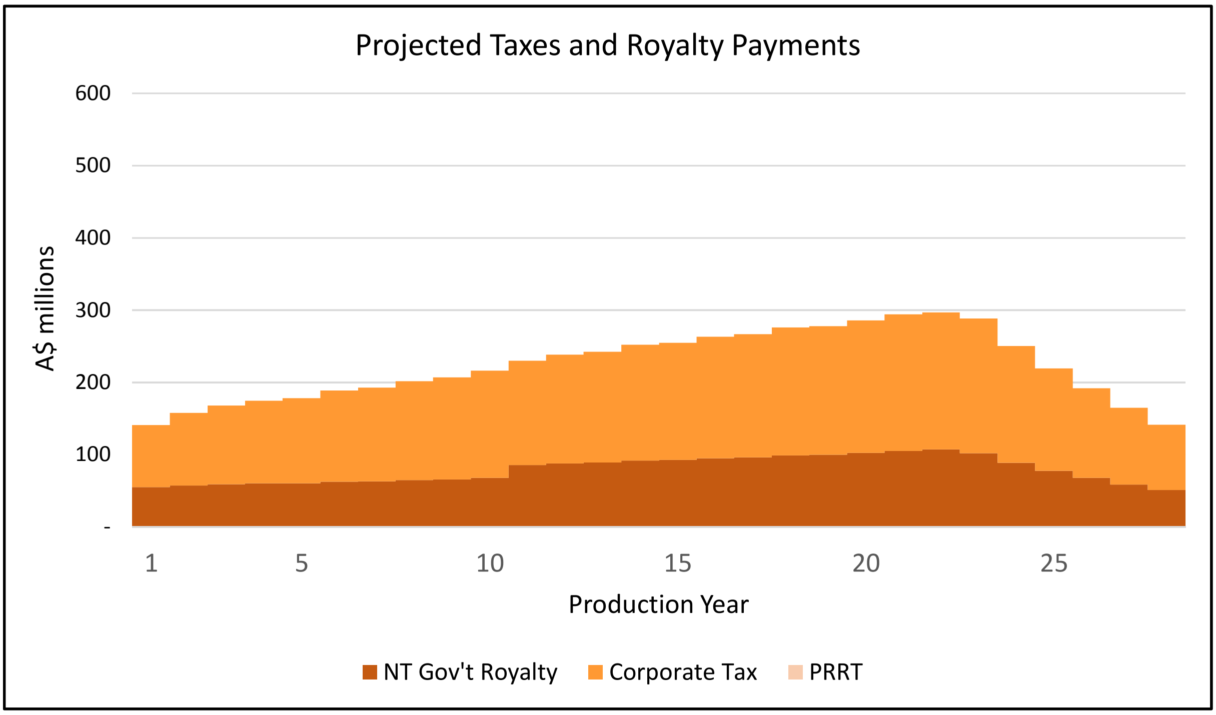
Developing these gas resources is also expected to significantly increase employment in the NT. Under the Success scenario, job creation is estimated to increase by nearly 4,200 full time equivalents (FTEs) by 2040. Developing this sector is projected to add $200 million to NT Government revenues. From 2020 to 2040, this increase is cumulatively (in NPV terms) almost $700 million (Deloitte, 2015).

The benefits of a successful shale gas development in the NT will be shared. Many of the benefits of shale gas production in the NT will accrue to the State and Federal Governments and to the Indigenous landholders.

Around half of the NT is covered by the Aboriginal Lands Right Act (ALRA). Some gas developments can be expected to take place on ALRA land. The Commonwealth makes matching payments to the Land Councils equal to the value of royalties paid by resource companies to the NT Government. The Land Councils distribute these funds to communities.

Figure 45 shows the projected taxes and royalties flowing to the above stakeholders from a national 4 trillion cubic feet (Tcf) shale gas development where, for the purposes of illustration, the project is economically breakeven for the project developer (i.e. Break Even Gas Price, BEGP).

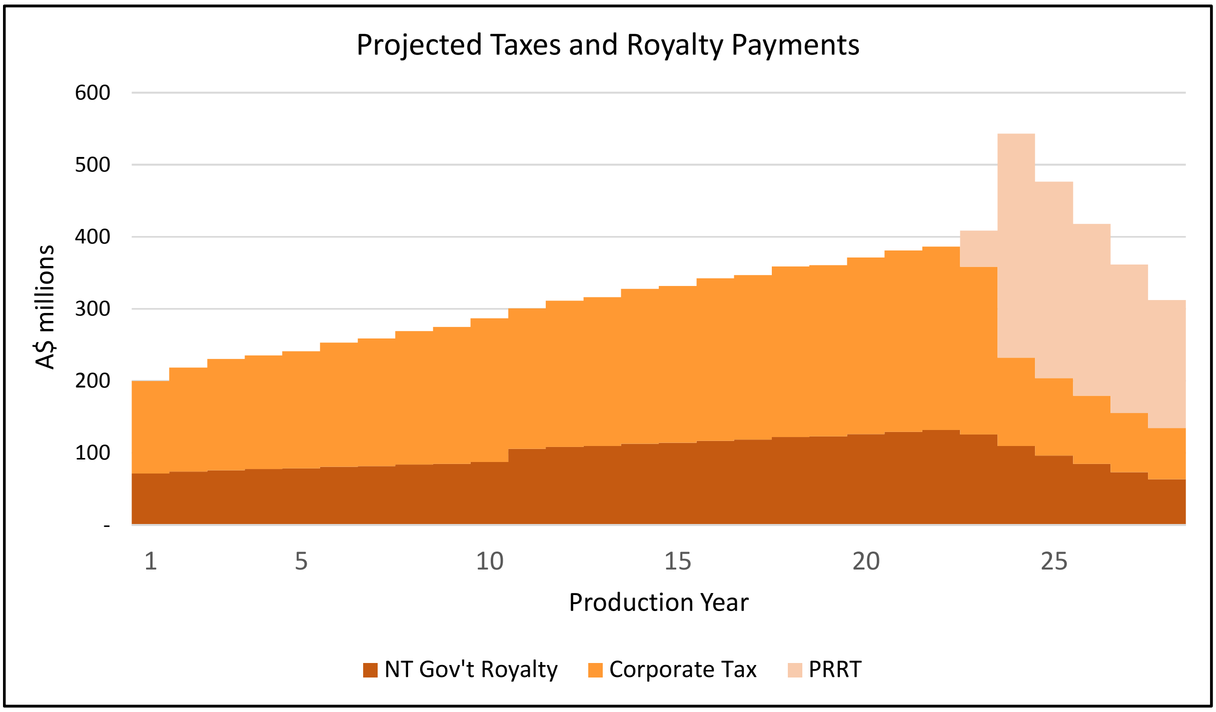
Figure 45 Projected taxes and royalty payments for the BEGP



Source: Santos, 2017

Figure 46 shows the effect on the amounts accruing to those stakeholders as a result of the project becoming more profitable for example where the (real) price per gigajoule increases $1.00 over the breakeven gas price. Note that the increase in profitability of the project significantly increases the flow of funds to stakeholders and results in the project beginning to pay PRRT (Petroleum Resource Rent Tax).

Figure 46 Projected taxes and royalty payments for the BEGP +$1/GJ



Source: Santos, 2017

Under the above breakeven scenario, an average of approximately 44% of the project revenues remaining after the deduction of project costs goes to government and indigenous stakeholders. Under the breakeven + $1/GJ scenario this percentage rises to approximately 49%; while under the breakeven + $2/GJ scenario there is a further rise to 56%. In this scenario, the total royalties paid over a 30 year period are estimated in Table 8.

Table 8 Estimated total royalties paid in a 30-year period

Estimated Royalty (A$MM)	Break-even gas price (BEGP)	BEGP + $1/GJ	BEGP + $2/GJ
NT Gov't Royalty	2,293	2,868	3,443
PRRT	-	1,539	5,175
Corporate Tax	4,188	5,212	5,606
TOTAL	6,480	9,619 (+48%)	14,225 (+120%)

Source: Santos, 2017

There is a wide range of potential benefits for landholders as a result of natural gas activity on their properties, beyond the compensation paid to directly offset the footprint and inconvenience of natural gas activities (In 2015, Santos paid approximately $11 million in compensation to landholders across its onshore activities). These include:

- **Additional income streams** from natural gas activity would be a welcome addition to any farming business grappling with the adverse effects of ongoing drought conditions. Income can be generated through, for example, the sale of raw materials such as gravel for road construction.
- **New farm infrastructure** that enhances the farming business. For example, access roads to gas wells located to the advantage of the landholder
- **Opportunities for employment**. There are numerous examples of landholders gaining employment with companies or their contractors. Employment opportunities for young people in particular are helping to reverse the trend of regional population decline by providing additional career options in regional area.
- **Additional selling point** for properties on the market. There is anecdotal evidence of properties being advertised in Queensland for sale with ‘gas wells’ listed as a selling feature over recent years, and this is likely to continue.
- **Improved community infrastructure and services.** Santos has a strong track record of contributing to communities with a focus on health, education, infrastructure, the environment, youth, indigenous opportunities, local businesses, the arts, community organisations and events, and volunteering. In Queensland, GLNG has made over $200 million worth of contributions to regional communities, including important legacy investments in major infrastructure including road upgrades and maintenance; aeromedical services; airports; affordable housing and rent assistance initiatives; sewerage infrastructure; and weed and management programs (Santos, 2017).

Local Employment & Training Opportunities

- In undertaking our activities, Santos always seeks opportunities for inclusion of local engagement in employment and on-the-job training.
- Provisions for employment and training are captured in the EP 161 exploration agreement and Santos works with the Northern land Council to ensure opportunities are presented to traditional owners.
- In our NT activities in the past few years, opportunities were provided for Aboriginal employment and on-the-job training through:
- Intract Indigenous Contractors undertaking civil works for the Mereenie Appraisal Development Drilling project (this activity allowed Intract to explore for new work in other industries and opened the door to opportunities in the Cooper Basin).

- Terrex Seismic for Southern Amadeus Seismic Program
- Rusca Bros Services while undertaking McArthur Basin drilling activities in 2014 (preparation of access road and lease pad for the exploration well hole. Rusca had an impressive record for Aboriginal employment, but on this project increased its workforce through employment of local Traditional Owners).
- In Queensland, Santos' GLNG project created more than 360 opportunities during the exploration and construction phases, including employment in GLNG's core business roles which are ongoing.
- In 2012, GLNG launched its three-year Aboriginal cadetship program in Queensland, with five cadets commencing positions ranging from human resources roles to working in environment and gas supply teams. The cadetships provide on-the-job experience alongside gaining relevant work qualifications, and ensure cadets develop professionally in order to be competitive in the oil and gas industry or wherever they choose to work.

8.0 Conclusion

We hope this submission assists the Inquiry Panel make recommendations that allow the onshore gas industry in the Northern Territory to grow and deliver benefits to many in the Top End. Whilst of another scale, the development of shale gas in the United States has sent carbon emissions plunging (with gas replacing coal-fired electricity), stimulated jobs and local economies, and turned the nation from an energy importer to one that is now self-reliant. A commensurate opportunity awaits the NT

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.

This submission draws on our decades of experience and goes into detail on many of the technical aspects of our business. It aims to address, in a comprehensive way, the concerns that have been expressed to the Panel by various members of the community.

The company stands ready to assist the Inquiry Panel should it seek further information or clarification on any aspect of this document, and looks forward to the Inquiry's Interim Report.

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