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Long-term monitoring of decommissioned onshore gas wells

GISERA W20 Final Report

Cameron R Huddlestone-Holmes, Elaheh Arjomand, James Kear

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Summary

At the end of their design life, petroleum wells are removed from production and decommissioned. Decommissioning (also referred to as abandonment) is the point where a well is taken out of service, permanently sealed (plugged) and all surface infrastructure is removed. The goal of decommissioning the well is to ensure the integrity of the well in perpetuity, effectively re-establishing the natural barriers formed by the impermeable rock layers that were drilled through to reach the resource during the well construction phase. Concern over the potential for decommissioned wells to leak (failed well integrity leading to movement of fluids along or into/out of the well) was raised by a number of stakeholders to the Northern Territory Hydraulic Fracturing Inquiry, which made recommendations about ongoing monitoring of decommissioned wells. Understanding and monitoring the ongoing integrity of decommissioned onshore petroleum wells in the Northern Territory is the focus of this study.

Three sets of fundamental information were required to address monitoring of decommissioned onshore petroleum wells in the Northern Territory:

1. How could leaks occur? (Section 3: Well integrity risk assessment)
2. What monitoring techniques are available? (Section 4: Well integrity monitoring)
3. What decommissioning and remediation techniques are available? (Section 5: Well decommissioning and remediation

Based on the information gathered, monitoring options were considered for:

1. Well integrity monitoring for decommissioned wellsWells that are yet to be decommissioned (section 6.1)
2. Wells which are already decommissioned and that have been relinquished or orphaned (section 6.2)

The final stage of the project provides examples of monitoring for scenarios of compromised well integrity (section 7).

A key component of the current project is an assessment of well integrity risks post-decommissioning for wells in the Northern Territory. This risk assessment allows the critical parameters that contribute to well integrity risk in decommissioned wells to be determined so that appropriate monitoring approaches can be considered. For contaminants (a substance that causes a change in the biological, chemical or physical properties of an environmental endpoint that may produce an adverse effect) to leak from an underground source to an environmental endpoint via a decommissioned well, three things need to occur:

- A fluid pathway: There needs to be a pathway through or along the decommissioned well for fluids or gasses to leak through – a well's integrity has to be compromised for this to occur
- Contaminant source: Contaminants need to be able to flow from the source at a rate and volume sufficient to reach the environmental endpoint

- Driving force: A pressure or buoyancy difference needs to exist such that contaminants are encouraged to flow between the source and the environmental endpoint

The risks assessment identified five key failure modes for decommissioned wells. These all impact on the well's integrity (the fluid pathway):

- Cement sheath failure
- Casing failure
- Plug Failure
- Surface Equipment Failure
- Cement bond failure (creation of micro-annuli)

For a well integrity failure to create a pathway for fluids to reach the environment, a combination of these failure mechanisms that connect the fluid source to the environment (atmosphere or an aquifer for example) needs to occur. The hazards that may lead to these failure mechanisms exist throughout the well's life and are actively controlled through well integrity management processes.

Well integrity monitoring for decommissioned wells has two broad objectives. The first is to monitor the well barrier components to confirm that they are meeting their performance criteria and are not degrading. The second objective is to monitor for the consequences of breaches of well integrity that have led to a release of fluids from the well. Monitoring methods can be grouped by access to the well as follows:

- Direct subsurface monitoring of the well
- Direct surface monitoring of the well; and
- Indirect monitoring.

Direct subsurface monitoring of the well provides the only option for the first monitoring objective that allows for predictive monitoring and intervention. Direct subsurface monitoring of the well is not longer possible once a well has been fully decommissioned.

Direct subsurface monitoring after the first stage of well decommissioning will allow the integrity of these wells to be confirmed. Monitoring of pressures at the well head can be conducted and data can be transmitted in real time. More advanced techniques, including those that use distributed fibre optic sensing may also provide information on fluid movement along a well and could be accessed while a wellhead was still on the well. However, there is little data available on the performance of these systems and the significance of data generated.

Direct monitoring at the surface (immediately above a well that has been fully decommissioned) through methane gas detection, along with indirect monitoring for methane at the well pad scale, is likely to provide the most effective monitoring for fully decommissioned wells. The buoyancy and mobility of methane gas means it is the most likely fluid to move along a well with integrity issues (as long as there is a methane source). The availability of reliable, robust and sensitive methane detectors that can be used in the field should allow leaks that reach the surface to be detected. Other methods may be deployed to investigate the source of methane (isotopic measurements, monitoring for longer chain hydrocarbons, monitoring groundwater).

For wells that have already been relinquished (or orphan wells), a campaign to conduct desktop studies to ascertain the well integrity risks posed by the wells combined with initial site surveys to check for methane gas anomalies will allow the design of an ongoing monitoring program.

Emerging technologies have the potential to improve the performance of both decommissioning and remediation techniques. Such emerging technologies utilise alternative materials and techniques to potentially achieve a well integrity seal which lasts longer and/or is more versatile than the current cement and steel based technologies. Remediation of well integrity issues is complex once a well has been decommissioned. Access to the well needs to be re-established and there are significant risks associated with this activity. Remediation of any well integrity issues immediately prior to decommissioning can make use of routine operations and is preferred.

Confirming the integrity of wells at the time of decommissioning is the best means of reducing their long term post decommissioning risk to a level as low as reasonably practical. Ongoing monitoring can be designed by considering the residual risk remaining at the time of decommissioning. Continued monitoring of decommissioned wells may no longer be required where potential fluid movement along the well is similar to the natural movement of fluid within the Earth’s crust.

Contents

Acknowledgement

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1 Introduction

At the end of their design life, petroleum wells are removed from production and decommissioned. In 2013, there were more than four million onshore hydrocarbon wells worldwide (Davies et al., 2014) with nearly 10,000 in Australia. Since the expansion of the coal seam gas sector, the number of onshore petroleum wells in Australia has risen to over 27,000 wells (GPinfo, 2021). Around 8,500 of these wells have been decommissioned and at some point, the remainder of these wells will need to be decommissioned. Understanding and monitoring the ongoing integrity of decommissioned onshore petroleum wells in the Northern Territory is the focus of this study.

Maintaining the integrity of petroleum wells is of central importance throughout their life cycle for environmental, safety and operational performance (International Organization for Standardization, 2017). Well integrity serves to protect the environment by preventing groundwater contamination (Jackson et al., 2013; Vidic et al., 2013) and the migration of fugitive emissions into the atmosphere (Davies et al., 2014; Miller et al., 2013).

Well integrity

Well integrity is an important concept in considering the risks that petroleum wells pose to the environment and can be defined as follows:

"the quality of a well that prevents the unintended flow of fluid (gas, oil or water) into or out of the well, to the surface or between rock layers in the subsurface (Huddlestone-Holmes et al., 2017)*."*

Well integrity is maintained through well barriers that are designed to keep fluids separate (API Guidance Document HF1, 2009). At the end of their operational life, the interior of wells are sealed with the installation of a series of cement 'plug' well barrier components across key underground rock layers. These cement plugs prevent fluids from flowing into, out of, or along the well (the process for decommissioning and remediating petroleum wells in the Northern Territory is more fully described in Section 5). Failure of individual or multiple well barriers could lead to the integrity of the well being compromised (Davies et al., 2014; King & King, 2013). A well integrity failure may allow a well to become a permeable conduit for the flow of formation fluids (Watson & Bachu, 2009) which may risk the release of these fluids to the environment.

A fluid is a substance that can flow, such as gas, oil or water. In this context, the source of the fluids would likely be underground rock layers and the potential destination (environmental endpoint) could be a different underground permeable rock layer, the soil surrounding the well, a local surface water body or (in the case of gasses) the atmosphere.

The focus of this project is to evaluate well integrity monitoring approaches for decommissioned onshore gas wells in the Northern Territory. The project has developed an approach for assessing potential monitoring techniques against the risks of well integrity failure and as such provides guidance on suitable monitoring strategies commensurate with the risks posed by decommissioned wells.

The Code of Practice : Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) sets out a stringent set of requirements for managing well integrity throughout a well's life cycle, including specific requirements around decommissioning wells at the end of their life. The monitoring methods investigated in this project take the requirements of this code of practice into account.

2 Project background

2.1 Background to decommissioned wells

Decommissioned wells are the physical infrastructure legacy remaining at the end of the petroleum well 'life-cycle'. Prior to decommissioning, each well will have been designed, constructed and operated to the end of it's useful life. The phases of this well 'life-cycle' span from the well design phase through to post-decommissioning (illustrated in Figure 1 below). The phases which precede decommissioning play a very important role determining in the long-term integrity of decommissioned wells.

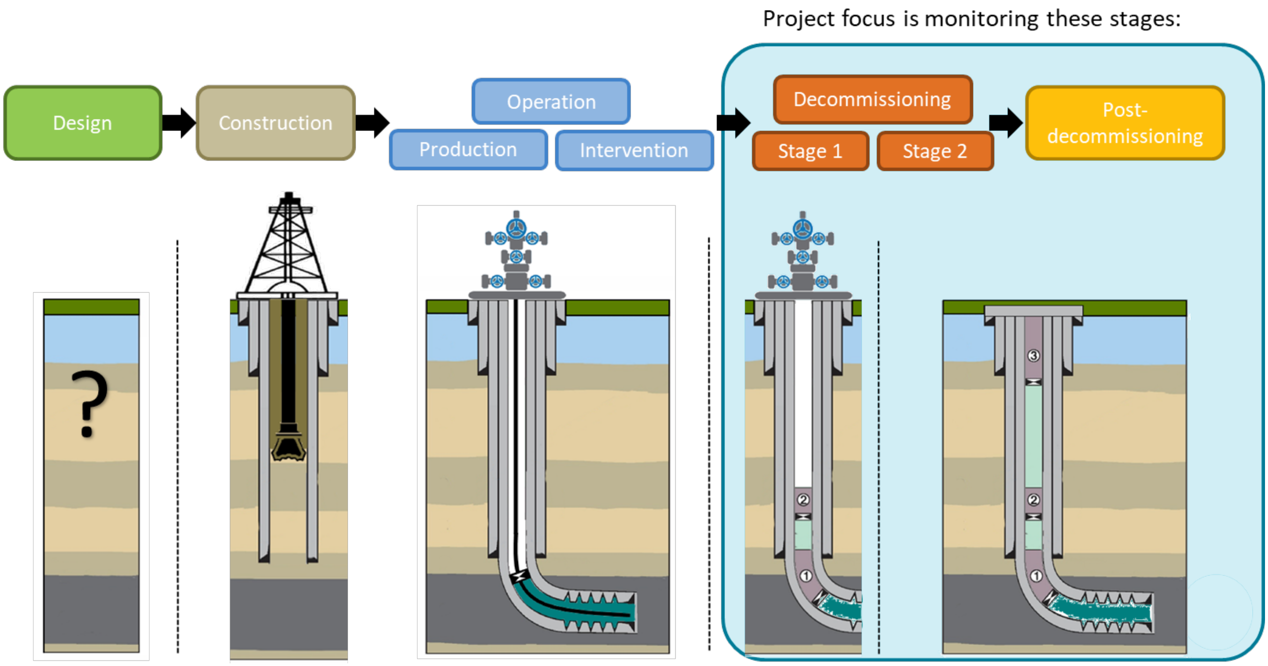

Figure 1 - Schematic showing the stages of the well 'life-cycle'. The focus of this project is the monitoring methods which can be adopted during the decommissioning and post-decommissioning stages of the well 'life-cycle'.

Decommissioning (also referred to as abandonment) is the point where a well is taken out of service, permanently sealed (plugged) and all surface infrastructure is removed. The goal of decommissioning the well is to ensure the integrity of the well in perpetuity, effectively re-establishing the natural barriers formed by the impermeable rock layers that were drilled through to reach the resource during the well construction phase (International Organization for Standardization, 2017; Kiran et al., 2017; Standards Norway, 2021). The process of decommissioning the subsurface components of a well involves: confirming the well's integrity to ensure that there will be no movement of fluid into or out of the well, and placing barriers in the well to prevent the vertical movement of fluids between rock layers.

In the Northern Territory, the requirements for decommissioning are set out in the Code of Practice : Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019). Similar guidelines have been developed in other jurisdictions including the UK (Oil & Gas UK, 2015), Alberta, Canada (Alberta Energy Regulator, 2018) and Queensland (Queensland Department of Natural Resources Mines and Energy, 2019).

2.2 Pepper Inquiry recommendations

Concern over the potential for decommissioned wells to leak (failed well integrity leading to movement of fluids along or into/out of the well) was raised by a number of stakeholders to the Northern Territory Hydraulic Fracturing Inquiry (Pepper et al., 2018). Two of the recommendations of the Northern Territory Hydraulic Fracturing Inquiry (recommendations 5.1 and 5.2) relate to ensuring and monitoring the integrity of decommissioned wells:

Recommendation 5.1

> *That prior to the grant of any further exploration approvals, the Government mandates an enforceable code of practice setting out minimum requirements for the decommissioning of any onshore shale gas wells in the Northern Territory. The development of this code must draw on world-leading practice. It must be sufficiently flexible to accommodate improved decommissioning technologies.*
>
> *The code must include a requirement that:*
>
> - *wells undergo pressure and cement integrity tests as part of the decommissioning process, with any identified defects to be repaired prior to abandoning the well; and*
> - *cement plugs be placed to isolate critical formations and that testing must be conducted to confirm that the plugs have been properly set in the well.*

Recommendation 5.2

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

Recommendation 5.2 requires regular monitoring of wells post decommissioning but does not make any comment about what that monitoring would entail or the duration which the monitoring should be conducted for. Further, the inquiry did not make any recommendations about what acceptable integrity performance is for a decommissioned well.

2.3 Project components

This project seeks to assist in the development of suitable approaches to monitoring decommissioned wells in the Northern Territory. Where the components of the study are depicted in Figure 2 below. Initially, three sets of required information were gathered to answer questions fundamental to the monitoring of decommissioned onshore petroleum wells in the Northern Territory:

1. How could leaks occur? (Section 3: Well integrity risk assessment)

2. What monitoring techniques are available? (Section 4: Well integrity monitoring)
3. What decommissioning and remediation techniques are available? (Section 5: Well decommissioning and remediation

This information is required to understand the context in which the monitoring of Northern Territory onshore decommissioned petroleum wells will be undertaken. The information gathered in these sections was combined to develop potential approaches to long-term monitoring of wells which are yet to be decommissioned (currently operating and future wells - section 6.1) and of wells which are already decommissioned (relinquished wells - section 6.2).

The final stage of the project provides examples of monitoring for scenarios of compromised well integrity (section 7).

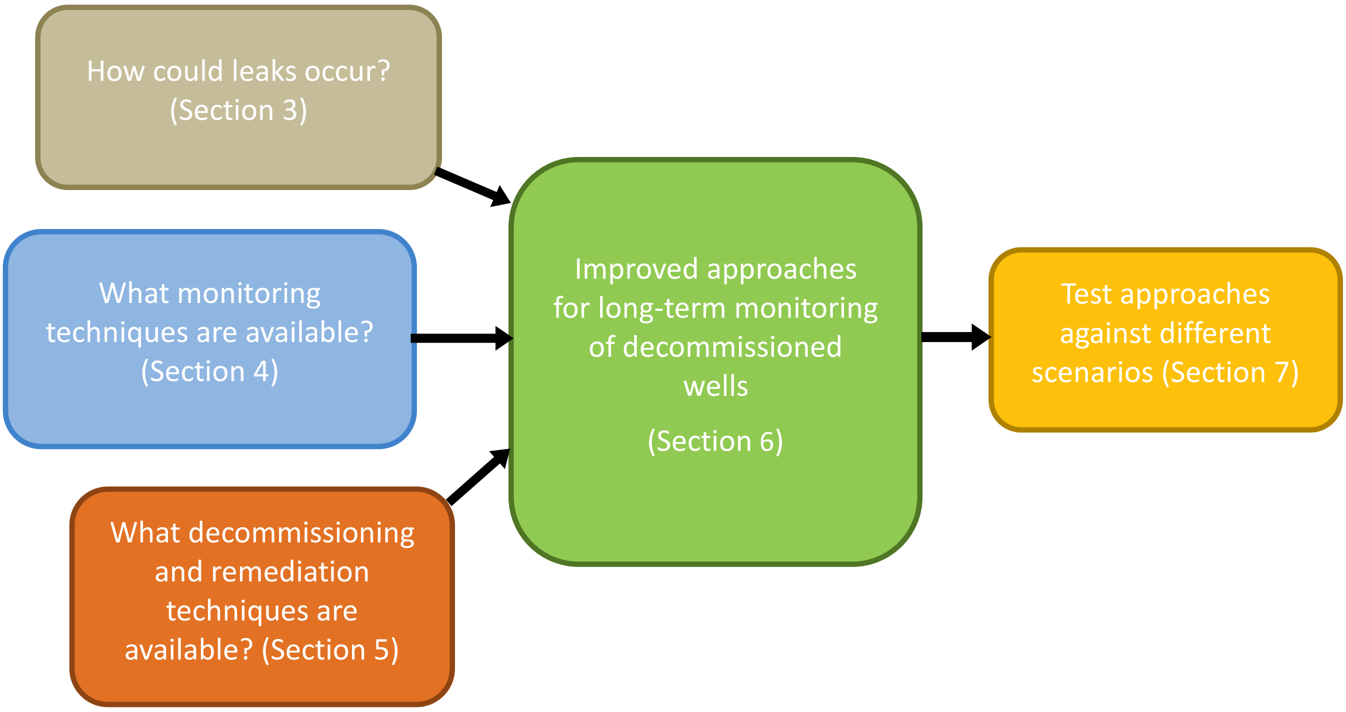

Figure 2 - Components of this study

3 Well integrity risk assessment

A key component of the current project is an assessment of well integrity risks post-decommissioning for wells in the Northern Territory. This risk assessment allows the critical parameters that contribute to well integrity risk in decommissioned wells to be determined so that appropriate monitoring approaches can be considered. There is limited data available on post decommissioning well failures in the Northern Territory and internationally (Huddlestone-Holmes et al., 2017) so a quantitative risk assessment will not be possible. Instead, a qualitative risk assessment approach that allows possible failure modes and their plausibility will be used.

According to International standard ISO 31000:2009, the risk is defined as the "effect of uncertainty on objectives”, which comprises both positive and negative effects. Therefore, risk assessment analyses should explain the type of the event which might take place (risk identification), the chances of occurrence (risk analyses), and the subsequent consequences (risk evaluation) along with the uncertainty. There is limited long-term data available on the post-decommissioning performance of well barrier elements, primarily due to decommissioned wells being sealed and therefore not accessible for downhole investigations. Performing a quantitative risk assessment on well barrier element failures in decommissioned wells is therefore challenging.

The key component of the qualitative assessment of decomissioned well integrity risks undertaken in this project is the identification of how components of a well may fail and the effects those failures may have on the wells' overall integrity. The qualitative approach the project has taken follows the Causal Networks method that is being implemented by the Geological and Bioregional Assessments Program (Geological and Bioregional Assessment Program, 2021) which is well suited to assessing risk where limited quantitative information is available. This approach, further described below, has elements of FMEA and Bayesian Networks which allow for focus on the potential failure modes and the chain of events that would need to occur for a well integrity failure that leads to a release of fluids to the environment to occur.

How could leaks occur from decommissioned onshore wells in the Northern Territory?

Well integrity is provided by the components (well barrier elements) of the well working together to create well barriersenvelopes (in this report we refer to these as well barriers). These well barriers prevent unintended fluid movement (leaks) into, out of or along the well. However, a failure of a single well component or a single well barrier does not mean that the integrity of the well will be compromised as multiple well barriers are required to be maintained for onshore petroleum wells in the Northern Territory, even when they are decommissioned (Northern Territory Government, 2019).

In the event that there is a well integrity failure (all the well barriers become compromised) a pathway may exist for fluids or gasses to leak out of or along the well. This well integrity failure will not necessarily result in a leak of contaminants into an environmental endpoint. For contaminants to leak from an underground source to an environmental endpoint via a decommissioned well, three things need to occur:

- **A fluid pathway**: There needs to be a pathway through or along the decommissioned well for fluids or gasses to leak through – well integrity has to be compromised for this to occur
- **Fluid source**: Contaminants (a substance that causes a change in the biological, chemical or physical properties of an environmental endpoint that may produce an adverse effect) need to be able to flow from the source at a rate and volume sufficient to reach the environmental endpoint
- **Driving force**: A pressure or buoyancy difference needs to exist such that contaminants are encouraged to flow between the source and the environmental endpoint

Figure 7 shows the interaction between the activities and situations which could cause stress to the well barrier components and the potential link to contamination of environmental endpoints in the event of well integrity failure.

3.1 Causal network analysis overview

The causal network method used in this assessment is based on the method adopted by the Geological and Bioregional Assessments program, which applied assessed potential impacts on water and the environment from unconventional resource development (Peeters et al., 2022). The method is well suited to exploring cause and effect relationships and qualitatively evaluating risk where there is limited quantitative data on risk likelihoods.

Causal networks are graphical models that describe the cause-and-effect relationships between drivers that initiate activities and endpoints that may be impacted by the activities. The network consists of nodes connected by links. The nodes represent the drivers, activities, processes and endpoints (valued assets) in the system being assessed, and the links represent the cause-and-effect relationships between nodes. The links represent effects (i.e. a change in node B that is caused by a change in node A) whereas pathways describe how activities impact on an endpoint. Causal networks are particularly useful for illustrating complex systems with interconnected components. They allow a comprehensive identification of the inferred direct and indirect pathways for impact and for the cause-and-effect relationships of each step between an activity and an endpoint is transparently and concisely documented. Causal networks can also be used to evaluate likelihood and consequences of cause-and-effect relationships, as well as mitigation strategies.

This project also evaluated Failure Modes and Effects Analysis (Liu et al., 2013) and Bayesian Networks (Bobbio et al., 2001) as approaches to conduct this risk assessment. While amenable to uncertainty, these two methods rely on a level of quantification of likelihood and consequence that is not readily available for decommissioned wells. The causal network approach has elements of FMEA and Bayesian Networks (Peeters et al., 2022) in that it allows the cause-and-effect relationships and resulting impact pathways to be identified. Using this approach the potential failure modes and the chain of events that would need to occur for a decommissioned well integrity failure that leads to a release of fluids to the environment to occur have been identified.

When applying the causal network approach to well decommissioning, the key physical characteristics of a well (such as casing, cement, cement plugs, geological formation, stress state) and the well operations characteristics (well operational history, well integrity testing and monitoring, decommissioning activities) have been considered. The most plausible failure modes have been identified, and impossible or highly implausible failure modes excluded. Identifying plausible failure modes allows the consideration of appropriate monitoring methods to be considered. The causal networks also allows monitoring methods to be assessed to test whether they may negatively impact on well integrity risks by introducing additional failure paths or exacerbating existing ones.

The process for creating a causal network has 3 steps. The first is to establish the scope of causal network. In this case it is for well integrity for decommissioned petroleum wells. This is followed by establishing a conceptual model of the system being evaluated to explore the activities, processes and endpoints that need to be included in the causal network. The causal network can then be built, representing the conceptual model as a directed acyclic graph (DAG) in which the nodes represent the drivers, activities, stressors, processes and endpoints, and the links are the inferred causal relationships between those nodes (Peeters et al., 2022).

3.2 Conceptual model for decommissioned well integrity

Conceptual models are a useful way of describing a complex system in a way that captures its key aspects. They allow the system as a whole to be described with conceptual clarity by discarding some detail and focussing on key components and concepts. The challenge is to find the level of requisite simplicity that accurately describes the system without losing important detail (Stirzaker et al., 2010).

Conceptual models are very commonly used, and some examples include teaching, risk assessments, system design, and software engineering. We need a conceptual model so that we can build our causal network (the causal network itself is a form of conceptual model).

At its very simplest, a conceptual model for decommissioned well integrity has three components (Davies et al., 2014):

1. a fluid source,
2. a driving force for fluid movement, and
3. a pathway for the fluid to flow along.

For a decommissioned well to have an adverse impact, then all 3 components need to occur and the pathway needs to connect the fluid source to an environmental endpoint.

3.2.1 Fluid source

A petroleum well will pass through numerous layers of rock that can contain fluids of varying composition. These fluids can include water, hydrocarbon liquids (oil), hydrocarbon gas, and other gasses (such as carbon dioxide or nitrogen) or a mixture. The composition of these fluids can vary greatly. Water may range from fresh to highly saline and may contain a range of inorganic and organic compounds. Similarly hydrocarbons can range from heavy oils to methane gas. The composition of the fluid will determine the type of impact it will have on the environment should a pathway and driving force exist.

The size of the fluid source and the ability of the fluid to flow from the source are also important characteristics. A small, confined resource may not provide enough volume of fluid to flow along the full length of a pathway. The flow rate of fluid out of a source will depend on the permeability of that source and the viscosity of the fluid, controlling the rate at which a fluid can be delivered to the pathway and the magnitude of the force driving the fluid flow (section 3.2.2).

An exploration well that does not intercept a hydrocarbon occurrence or aquifers may not have a fluid source at all, whereas a well drilled into a conventional gas reservoir has a large potential fluid source.

3.2.2 Driving force

For fluid to flow along a pathway, there has to be a driving force for the fluid to flow. There are two potential sources of driving force. The first is buoyancy where the density of the fluid in the source is lower relative to the density of the surrounding gasses and liquids. In the case of hydrocarbon and related gasses (carbon dioxide), the buoyancy of the gas itself is usually enough to provide a driving force for fluids to flow towards the surface should a pathway be present.

The second is overpressure, where the pressure of fluids within the rock is greater than the hydrostatic pressure (pressure equal to the weight of the column of fluid above it). When water in rock layers is at hydrostatic pressure, there is no driving force for the water to flow vertically. Overpressures can occur in some geological settings when there is an increase in the amount of fluid or gas in the rock, or when the amount of pore space is reduced. If the fluid cannot escape, the result is an increase in pressure. Overpressures can only occur where there are impermeable layers preventing the vertical flow of water, otherwise the water would flow upwards to equalise back to hydrostatic pressure. Overpressures provide a driving for fluids to flow towards the surface should a pathway be present.

Buoyancy and overpressures can combine where a fluid source containing gas is overpressured.

3.2.3 Fluid pathway

Petroleum wells are drilled to create access to the sub-surface and, in most cases, to create a pathway to allow the flow of fluids from the reservoir to the surface (the exception is for wells used for monitoring or measurement purposes). During well operations such as hydrocarbon production, hydraulic fracturing or well testing, controlled fluid flow into, out of and along the well is intended. Once decommissioned, any flow of fluid into, out of, or along the well is unintended. For this flow to occur after a well has been decommissioned a breach of well integrity according to the concept of well integrity described in section 1 must have occurred, leading to a leakage pathway being established between a source of fluid and a receptor (either the surface or a permeable subsurface formation).

For a pathway to allow flow from a fluid source to a receptor, it must connect the two. Figure 3 shows possible pathways for leakage from a decommissioned well. A complete pathway is likely to involve several segments. The integrity of a decommissioned wells is highly dependent on the integrity of the cement plugs set inside casing during decommissioning. Failure of these plugs may allow fluid movement along the inside of the well. In the example shown in Figure 3, leakage through the reservoir zone isolation plug (P1) may be created if there is a fluid pressure build-up or if there is an injection from nearby production wells. If the plugs located in the reservoir (P1) and other zones along the well (P2) were to leak, the plug near the surface (P3) could become exposed to fluid pressurised from the reservoir and if that plug fails, allow fluid to be released to the surface (R1). Fluid may also move through the annuli between casing strings (P4) or the interface between casing and cement (P5) or cement and the formation (P6). If the casing and cement along the well are compromised, fluid may move into or out of the well or between annuli (P7). Fluid may also move around casing shoes (P8).

Combined, these pathway segments could lead to a release of fluid at the surface through the well (R1), through casing annuli (R2) or along the well-formation interface (R3). Fluid may also be released from a well to permeable formations and aquifers (R4).

The leakage pathways shown in Figure 3 can only occur when a number of different well barrier elements fail or become compromised. Well barrier elements can include the steel casing, cement sheath, production tubing, cement plugs, mechanical plugs and other downhole equipment. The stressors that lead to well barrier elements failing can be categorized into two different groups; primary stressors and secondary stressors (Weideman & Nygaard, 2014). Primary stressors generally relate to the construction of a well, including drilling, casing and cementing while secondary stressors are associated with the events and conditions that occur after cementing is complete (Weideman & Nygaard, 2014).

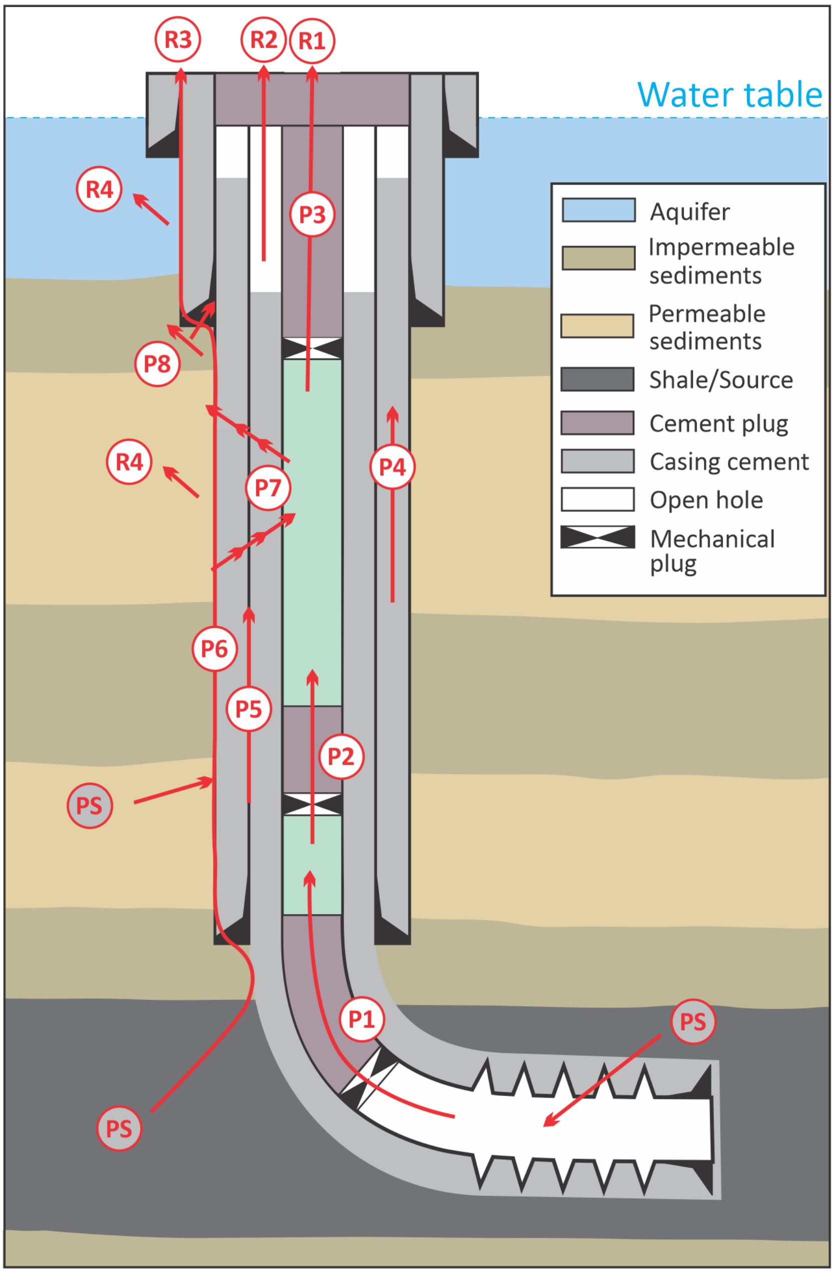

Figure 3: Schematics of a plugged well and the leakage pathway segments (Pn) and points of release (Rn). PS refers to pathways from sources of fluid into the well (Babaleye et al., 2019; Nichol et al., 2000)

Figure 4 illustrates the possible locations of leakage pathways caused by well barrier element failures, along with the failure mechanisms. Table 1 shows the relationship between the leakage pathways and failure mechanisms for the well barrier components. Primary stressors can cause mechanical failure of the casing (casing burst/collapse, failure mechanism b in Figure 4) (Crow et al., 2010; Weideman & Nygaard, 2014). For instance, casing strings undergo internal pressure and temperature cycling during the fracturing process caused by fracturing fluid. The driving forces

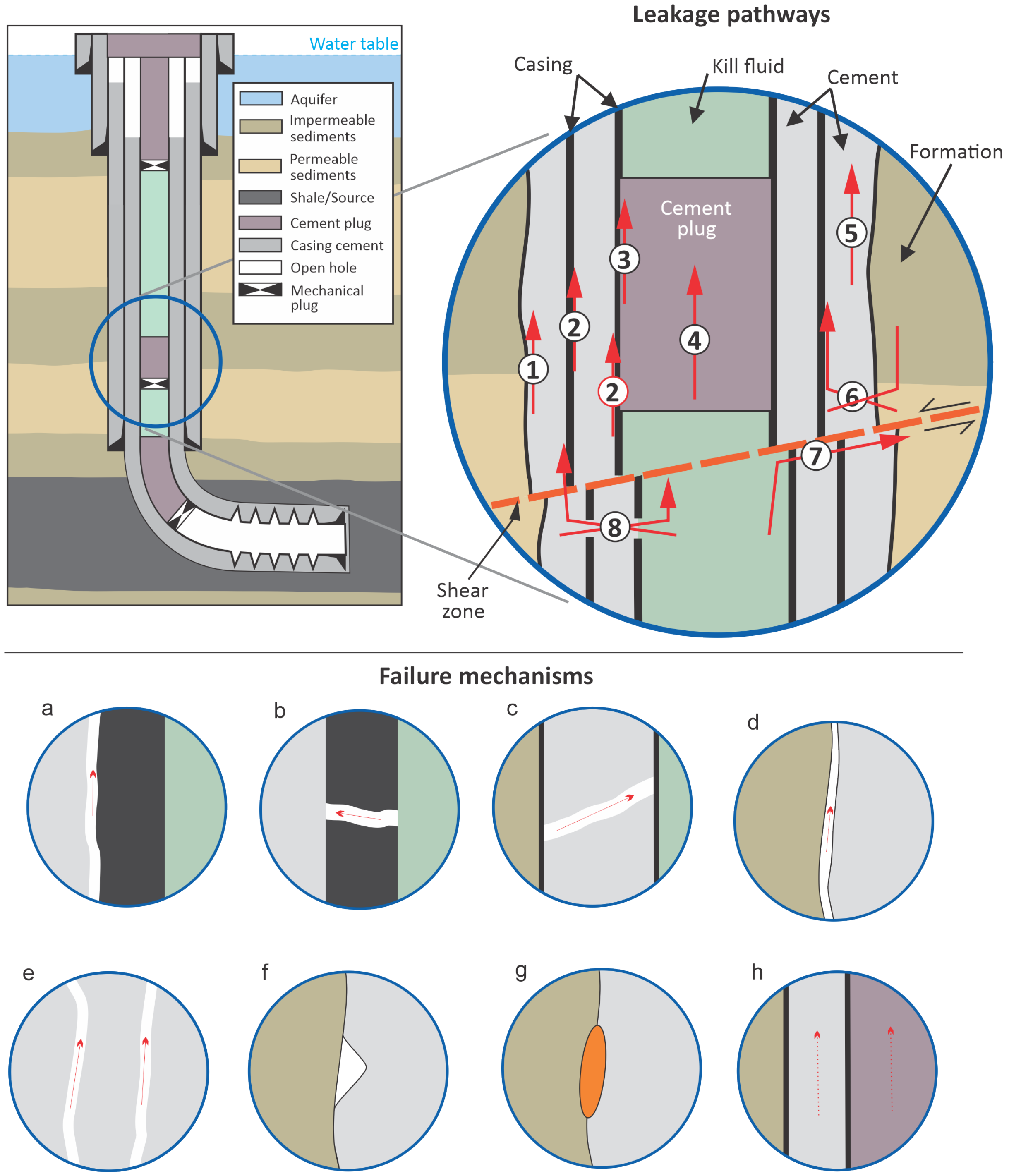

Figure 4: Routes for fluid leakage in a cemented wellbore: 1) between cement and surrounding rock formations, 2) between casing and surrounding cement, 3) between cement plug and casing or production tubing, 4) through cement plug, 5) through the cement between casing and rock formation, 6) across the cement outside the casing and then between this cement and the casing, 7) along a shear through a wellbore that has ruptured casing, 8) across failed casing and cement. (Celia et al., 2005; Davies et al., 2014))

may lead to piston force, buckling, ballooning, and temperature-induced deformation (King & King, 2013). Problems with the placement of cement during well construction are another example of a primary stressor. An unsatisfactory annular cementing job when the cement does not fill the annulus entirely (failure mechanism f, Figure 4), poor bonding due to the existence of drilling mud build up (failure mechanism g, Figure 4), and the development of channels in the cement (failure mechanism e, Figure 4d) may all compromise decommissioned well integrity.

Secondary stressors may include deterioration of cement, corrosion and wear of steel, erosion of casing, pressure and temperature cycling over the well's operating life and movement of the rock surrounding the well. These stressors can cause deterioration of cement bond strength leading to the creation of micro-annulus at cement interfaces with the casing and the formation (failure mechanism a and d, Figure 4) (Crow et al., 2010; Weideman & Nygaard, 2014), cement shrinkage, cement degradation (failure mechanism h, Figure 4) and cement mechanical failure (failure mechanism c, Figure 4) (Celia et al., 2005; Dusseault et al., 2000; Weideman & Nygaard, 2014). Shear failure mechanisms (Leakage pathway 1 in Figure 4) may happen in specific geological conditions such as reservoir compaction in the production period.

Table 1: Leakage pathways and well barrier components and potential failure mechanisms shown in Figure 4. Failure mechanisms may be due to primary stressors that occur during the installation or construction of the barrier or to secondary stressors that occur during the life of the well.

		Failure mechanisms									
		Primary					**Secondary**				
Leakage pathways and well barrier components		b – failure of casing	d – channels in cement	f – poor cement job, irregular wellbore	g – poor cement, residual drilling mud	h – permeable cement (installation or design)	a – failure of cement to casing bond	b – failure of casing (shearing, wear or corrosion)	b – cement failure,	e - failure of cement to formation bond– channels in	h – permeable cement (degradation)
1	Cement to formation micro-annulus										
2	Cement to casing micro-annulus										
3	Cement plug to casing micro-annulus										
4	Through cement plug										
5	Through annular cement										
6	From formation into outer annulus of the well (or from the well to formation)										
7	Sheared well										
8	Between annular zones of the well and/or centre of the well										

3.2.4 From conceptual model to causal network

The conceptual model described above has been used to construct a causal network with the components shown in Figure 5. The network considers the three components of source, driving force and pathway and elucidates how they contribute to decommissioned well integrity, and what aspects of a well's components and life cycle may lead to failures. The main emphasis of the network is on the pathway and its relationship to well integrity as this is where intervention and monitoring can be applied. The network also considers the consequences of failures on endpoints.

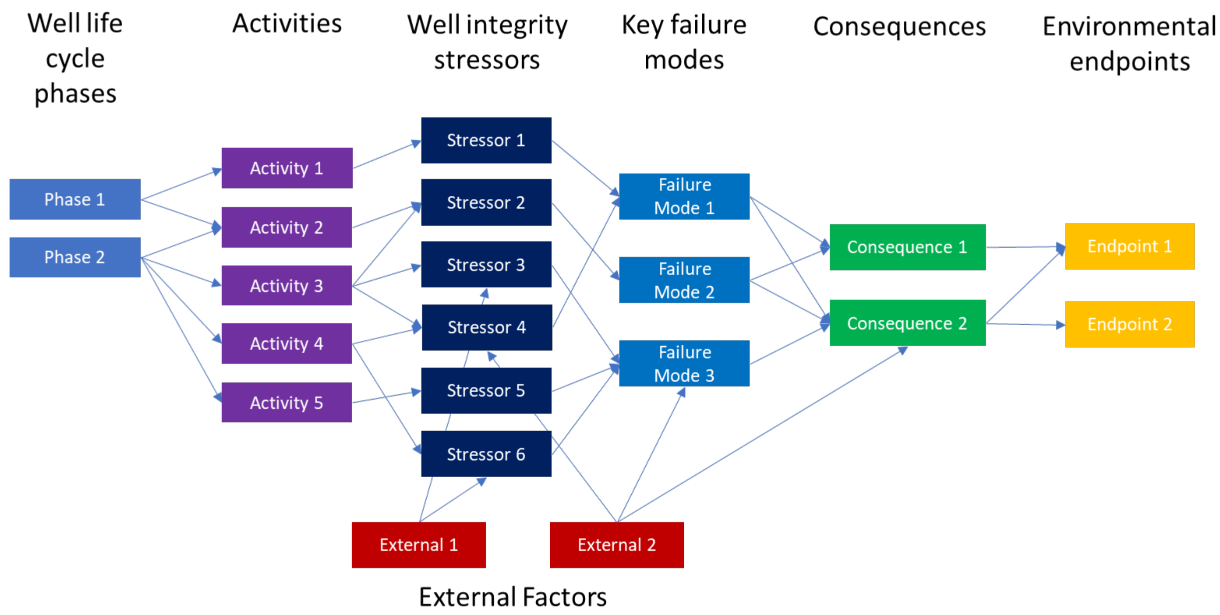

Figure 5: The causal network topology used for the risk assessment of decommissioned well integrity.

The nodes in the network represent:

- ***Well life cycle***: a description of the phases in a well's life cycle that determine well activities. The life cycle phases include design, construction, operation and decommissioning.
- ***Activities***: the individual activities that take place across a well's life cycle. These activities include drilling, cementing of casing, work overs and setting of plugs during the decommissioning.
- ***External factors***: the external factors that may impact on well integrity or the consequences of a well integrity failure. External drivers include the fluid source and driving force, geo-hazards and the properties of the rock that the well is drilled through.
- ***Well integrity stressors***: describe the stressors that may be placed on a well or a well's components because of well activities or external drivers. These include design or installation issues, degradation through time or due to operational issues and degradation due to external drivers.
- ***Key failure modes***: the ways in which a decommissioned well's integrity may fail, leading to the creation of a pathway. These include formation of micro-annular cracks, plug failures or casing failures.
- ***Consequences***: the outcome of a decommissioned well integrity failure in terms of fluid movement, such as release of fluid to the surface or between formations in the subsurface.
- ***Environmental endpoints***: the aspects of the environment that may be impacted by a decommissioned well integrity failure. They are the atmosphere, soil, water and aquifers.

3.3 Potential compromised decommissioned well leakage rates

Estimating the amount of fluid (gas or liquid) that could be released from a leaking decommissioned well in the Northern Territory is important for considering the potential consequences and impacts on environmental endpoints. The conceptual model described in section 3.2 of a fluid source, a pathway and a driving force provides a basis for a basic calculation to estimate potential flow rates from a source to an endpoint along a decommissioned well assuming current abandonment practices in the Northern Territory.

The composition of the source fluid influences potential flow rates as it determines the density and viscosity of the fluid. The three fluids that petroleum wells are most likely to encounter in the Northern Territory are water, hydrocarbon gas, and hydrocarbon liquids.

Hydrocarbon gas (assumed to be predominantly methane) would flow through any well integrity failure flowpath at a significantly greater rate than either water or hydrocarbon fluids as it has lower density (acting as a buoyancy driving force) and lower viscosity (leading to faster flow). Figure 6 below shows the potential (modelled) and internationally observed (Kang et al., 2014) methane emissions to atmosphere from decommissioned wells with compromised well integrity. These are compared to other greenhouse gas sources and savings (converted to methane emission equivalent) to provide greenhouse gas context to the scale of any potential methane emission from a leaking decommissioned well in the Northern Territory.

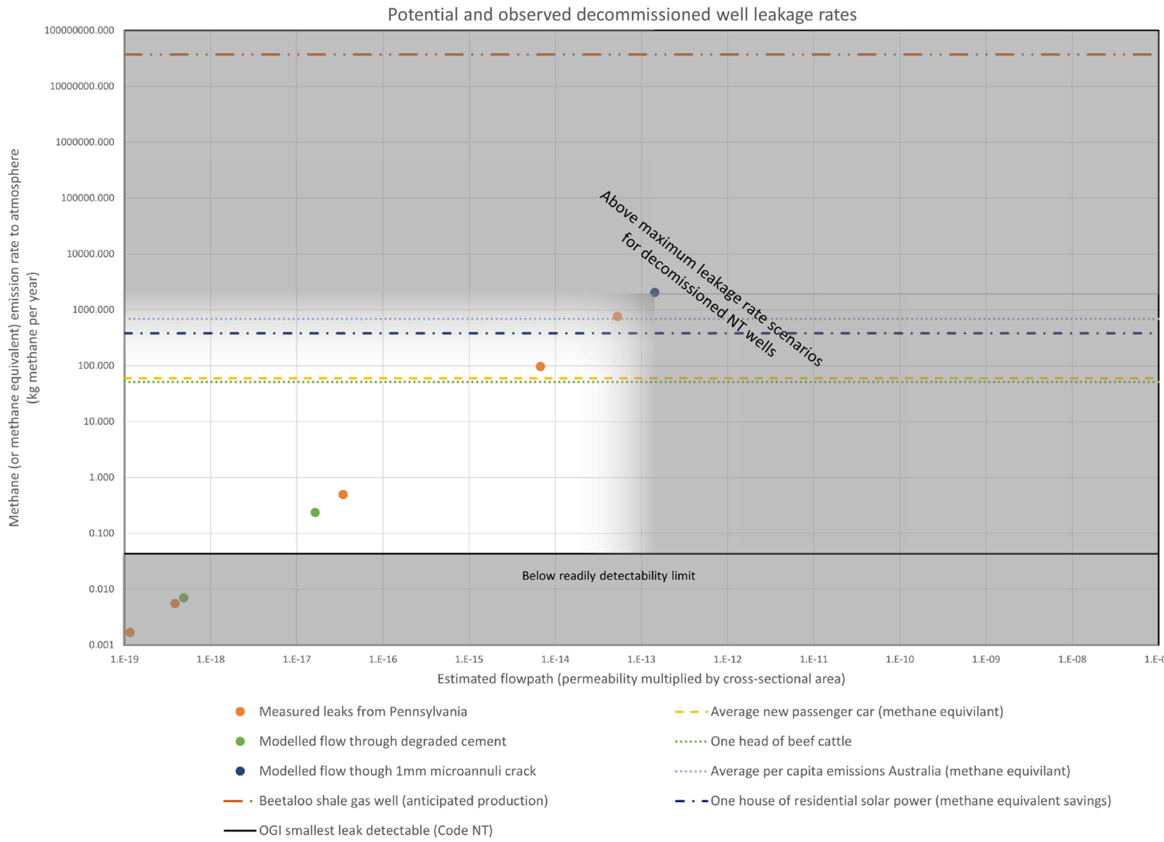

Figure 6 - Comparison of potential and observed decommissioned well leakage rates against other sources (or savings) or greenhouse gas emissions figure design after (Doble et al., 2022).

3.3.1 Methane leakage rate through degraded cement

As can be seen in Figure 6, the modelled rates of leakage for a Northern Territory wells through degraded cement (green dots) are broadly consistent with many of the observed rates of leakage in Pennsylvania (Kang et al., 2014). Two leakage scenarios were considered though degraded cement using simple Darcy flow equations. The equations and the assumptions selected for the calculation will tend to over-estimate the rates of potential leakage leading to a conservative assessment.

Firstly, leakage though a permeable cement plug (30 m total plug length (Ford et al., 2017) with a cement permeability of 5 µD (Godoy et al., 2015)) in a decommissioned Beetaloo well (3 km deep with 30MPa bottom-hole pressure) was estimated to be approximately 200 CH_4 g/year.

Secondly, leakage though a permeable cement sheath (cement permeability of 5 µD (Godoy et al., 2015)) outside the casing of the same decommissioned Beetaloo well (3 km deep with 30MPa bottom-hole pressure) was estimated to be approximately 7 CH_4 g/year.

These estimates of potential methane leakage from a Beetaloo well with degraded cement components are broadly in line with the observations from Pennsylvania (Kang et al., 2014) where a median methane flow rate of 475 CH_4 g/year was observed at well locations.

3.3.2 Methane leakage rate through microannuli

The maximum modelled potential flow rate scenario was though a 1mm microannulus (delamination between the well casing and the cement sheath) which was assumed to be continuous from the reservoir layer (methane source) to the surface. This scenario was modelled to have an estimated 2,000 CH_4 kg/year leak of methane to the atmosphere. This 1mm microannulus scenario is designed to demonstrate a 'worst-case' scenario and uses an aperture significantly higher than anticipated in the literature (Stormont et al., 2018).

Maximum leakage rate considered for the purposes of this study

The 'worst-case' scenario of microannuli leakage estimate is larger than the greatest leakage rate observation in Pennsylvania (Kang et al., 2014) of 753 CH_4 kg/year.

A larger methane leakage rate from a decommissioned well could be possible if the well barrier systems (cement sheath, steel casing or cement plugs) were to be absent or to fail in such a way they no longer provided any flow obstruction (e.g. no plugs inside casing were installed during decommissioning, or no cement was in the well annulus) and the reservoir was capable of a sustaining a significant methane flow. These total loss of well integrity scenarios are not plausible in wells decommissioned to modern standards. For legacy wells (also known as relinquished or orphaned wells, see section 6.2), a scenario involving a methane gas source without some form of abandonment is considered unlikely.

For the purposes of this study, an approximate maximum methane leakage rate from a decommissioned Northern Territory well with significantly compromised integrity is therefore estimated to be in the order of 1,000 CH_4 kg/year.

3.3.3 Greenhouse gas comparison of leakage rates

Figure 6 shows a comparison of this approximate maximum anticipated leakage rate (1,000 CH_4 kg/year) against other greenhouse gas sources (adjusted to methane emissions equivalent) including the average emissions from a modern passenger car (54 CH_4e kg/year - (Australian Government, 2021b)), one head of beef cattle (51 CH_4 kg/year - (Australian Government, 2018)), and average Australian per capita emissions (636 CH_4e kg/year - (Australian Government, 2021b)). Also shown in Figure 6 is a comparison to the greenhouse gas emissions offset by a 5kW residential solar installation (348 CH_4e kg/year savings - (Arif, 2013)). A 100 year global warming potential (GWP) for methane of 28 was adopted, as used by the Australian government in the NGER and Climate Active programs (Australian Government, 2021a).

3.4 Causal network results

The causal networks risk analysis approach produces a network diagram containing a large number of nodes and edge connections. Each node represents an important aspect, activity or task related to the construction, operation and decommissioning of a petroleum well which may have an impact on the integrity of that well post-decommissioning. The nodes that make up the causal network were identified during the qualitative risk assessment and represent the key interactions related to well system outcomes. A description of what each node represents and the interactions with downstream nodes and eventual well integrity outcomes are presented in a standalone document (Arjomand et al., 2022. https://doi.org/10.25919/3g4e-y522). This assessment will be updated periodically by future CSIRO projects as additional research is undertaken.

To simplify the representation of this information in the report, the universal network diagram (as shown in Figure 7) has been sub-divided according to five main identified failure modes. The nodal and edge connection data for each failure mechanism are presented as a subset of the universal network. This allows for presentation of the potential activities and stressors linked to a failure mode, and the possible consequences and impacts that potentially results from an occurrence of this failure mode.

The five failure modes are:

- Cement sheath failure - Section 3.4.1
- Casing failure – Section 3.4.2
- Plug Failure – Section 3.4.3
- Surface Equipment Failure – Section 3.4.4
- Cement bond failure (Creation of micro-annuli) – Section 3.4.5

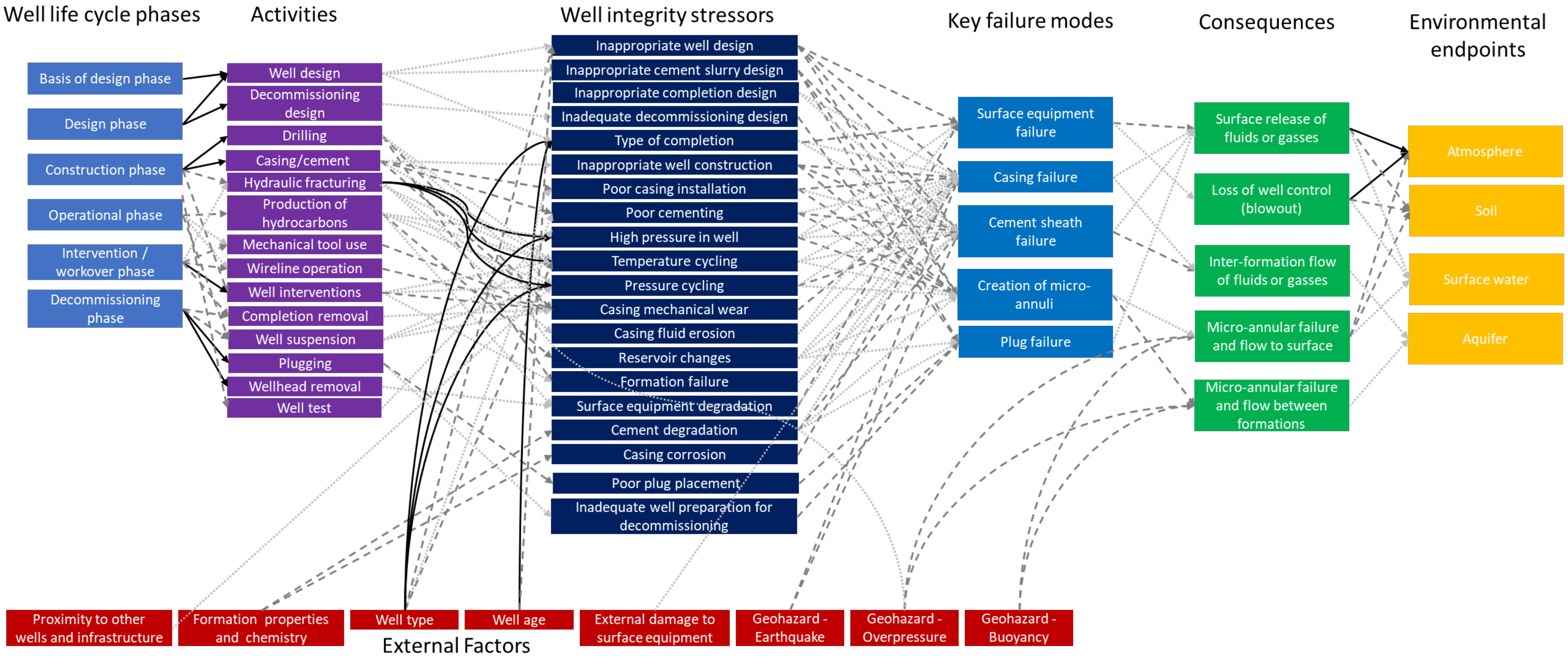

Figure 7 – The universal network diagram visualising the nodes and linkages from the Qualitative risk assessment. Any leakage from an onshore petroleum well would have a path which connects from the Well life cycle phases though the well activities, well integrity stressors, potential failure modes to consequences and possible environmental endpoints. The effectiveness of a monitoring program designed to detect the leak of contaminants from an onshore petroleum can be evaluated against this qualitative risk assessment to identify which upstream and downstream 'nodes' would be covered by the modelling approach. Printing at A3 size recommended.

3.4.1 Cement sheath failure

Cement sheath failure description

An integrity failure in the cement sheath could allow fluids and gasses to pass along the well behind the steel casing. If a cement sheath failure occurs across different permeable strata (aquifers or hydrocarbon reservoirs) and a pressure difference exists between those permeable strata, it could potentially lead to inter-formation movement of fluids and gasses. Alternatively, if the cement sheath failure spanned from a permeable stratum to the surface, and a driving force (overpressure or buoyancy) existed then the failed cement sheath could potentially act as a pathway for fluids and gasses to reach the surface.

The conceptual network of nodes associated with potential instances of cement sheath failure is shown below in Figure 8. There are six identified well integrity stressors which could plausibly lead to an instance of cement sheath failure and five well integrity stressors which could possibly lead to an instance of cement sheath failure. These stressors relate to the design and placement of the cement sheath, the operational conditions of the well and the potential degradation of the cement over time. These stressors are consistent with literature on potential causes of cement sheath failure which include poor slurry design, tensile stresses and shrinkage, the formation of leakage pathways through the bulk cement, cracks, and micro-annuli along the cement interfaces. (Ford et al., 2018).

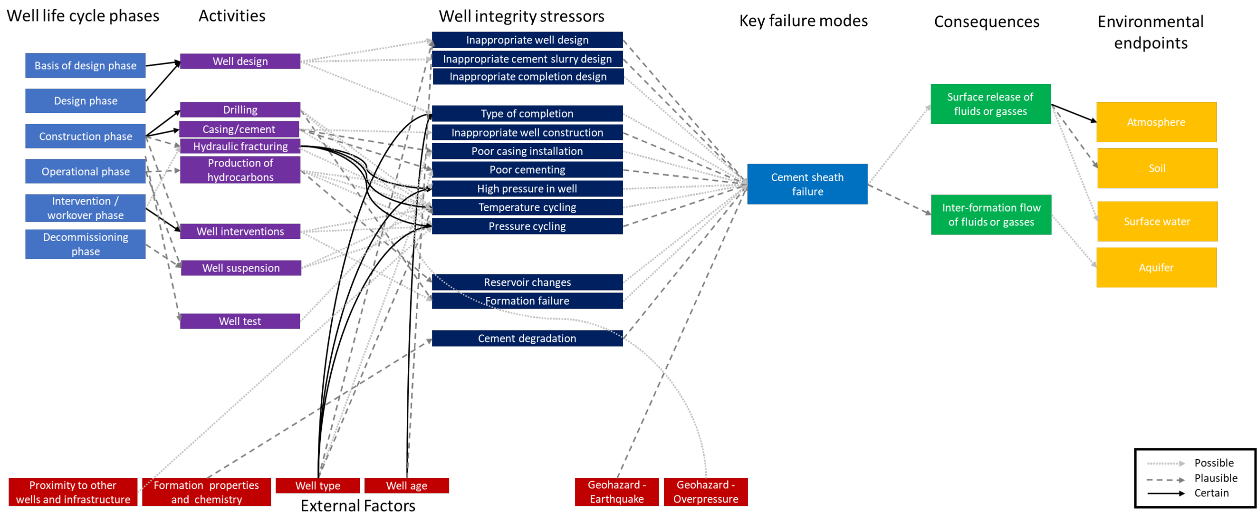

Figure 8: Subsection of the causal network associated with the cement sheath failure mode.

Cement sheath failure can be in the form of debonding between cement and casing or formation (this micro-annuli failure mode is considered separately in Section 3.4.5), shrinkage leading to tensile cracks, imposed stresses leading to brittle failure and degradation leading to increased bulk permeability (Reddy et al., 2007; M. Zhang & Bachu, 2011). During operation stresses exerted on the cement sheath include the mechanical and thermal stresses as the cement is subjected to pressure and temperature variations (Ravi et al., 2002a). These induced pressure and temperature variations from hydraulic fracture stimulation (Bellabarba et al., 2008), tectonic stresses, subsidence and formation creep, production operations (Goodwin & Crook, 1992; M. Zhang & Bachu, 2011), and injection of hot steam or cold water (Bois et al., 2011).

Imperfect placement of the cement sheath can also lead to reduced performance. This can be in for form of improper cement composition (Teodoriu et al., 2013; M. Zhang & Bachu, 2011) or contaminants such as mud cake and grease which can serve to deteriorate the bond strength between the cement with the casing and the formation during cementing. Contamination of cement may also weaken the mechanical properties of the cement sheath, potentially compromising the cement performance (Teodoriu et al., 2013).

Monitoring for cement sheath failure

During well construction and operation and critically prior to decommissioning, the integrity of the cement can be assessed by running cement bond log (CBL) and variable density log (VDL) to identify if cement sheath failures or cement debonding have occurred. Failure of one or more well barrier components may manifest itself by SCP (sustained casing pressure) or sustained annular pressure (SAP) also known as surface casing vent flow (SCVF) indications. SCP or SAP are sustained pressure either in between the tubing and casing or between casing strings when this pressure is not operator applied or not developed by the heating of the well during production (King & King, 2013).

It is important that regions of failed cement sheath identified in the cement bond log are remediated prior to decommissioning in order to preserve the integrity of the well barrier provided by the cement sheath.

3.4.2 Casing failure

Casing failure description

Steel casing strings are key well barrier elements in petroleum wells. An integrity failure in the well casing could allow fluids and gasses to pass from within the inner annulus of the well to the areas behind the failed casing. If the casing was to be compromised, it could potentially lead to movement of fluids and gasses to and from the cement sheath and surrounding rock. Such a failure and subsequent leakage may be difficult to detect especially if the movement of fluids is between subsurface formations (George E King and King, 2013).

Operation of petroleum wells requires a minimum of two well barriers to be maintained, therefore a production string would typically be used in the centre of the well to contain and transport the hydrocarbons to the surface. This would prevent migration of hydrocarbon fluids to the surrounding rock even in the event of casing failure during production. After decommissioning, the installed cement plugs would seal this pathway and prevent fluid movement in the central section of the well.

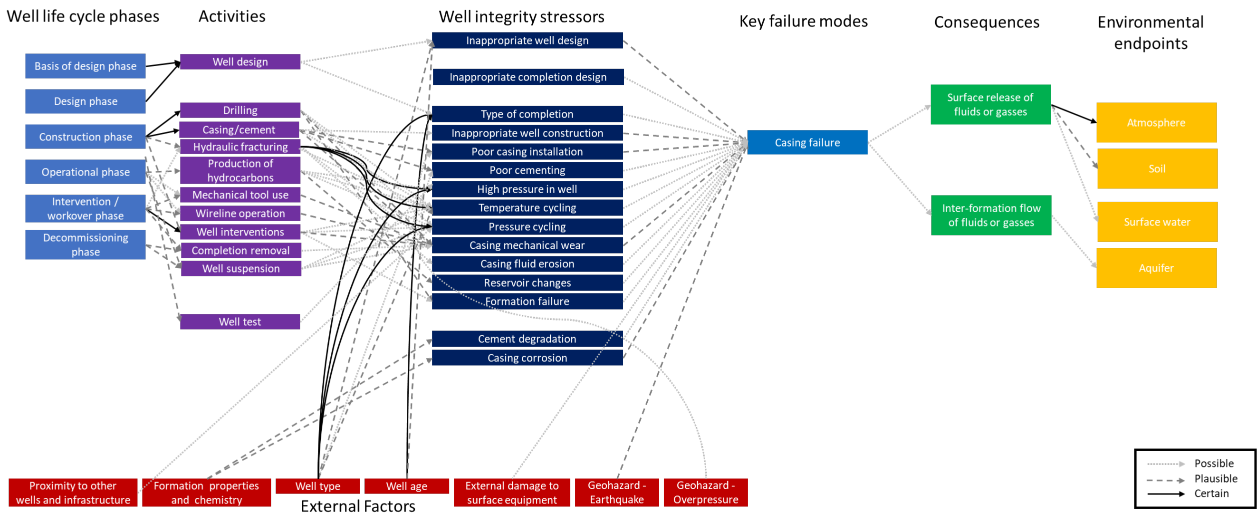

Figure 9: Subsection of the causal network associated with the casing failure mode.

The casing strings are subjected to downhole stresses during well construction, operation, intervention/workover and decommissioning. The stresses may be imposed by the formation (in-situ) such as regional tectonic movement and microearthquakes which can impose flexure on the casing string. Stresses can also be imposed on the casing as a result of well construction activities and fluid injection and production and changes in formation pore pressure (Mohammed et al., 2019). Failure of the surrounding cement sheath may also potentially lead to stresses being imposed on the casing by exposure to surrounding fluids. If the casing is not designed to be sufficiently strong to resist these imposed stresses the integrity of the casing may fail.

Monitoring for casing failure

Casing failure may be able to be detected via direct observation with a down-hole survey (i.e. deformation or physical damage) or through the resultant loss of integrity leading to pressure build-up behind the casing. Sustained casing pressure (SCP) can be described as any measurable casing pressure that restores after being bled down, relatable to any cause other than artificially applied pressures or temperature variations in the well. Where SCP is detected, the cause and leakage rate should be evaluated, and remedial actions should be undertaken (Kinik and Wojtanowicz, 2011; Rocha-Valadez et al., 2014).

3.4.3 Plug Failure

Plug Failure description

The primary goal of cement plugs installed during decommissioning is to prevent formation fluid movement up the interior of a decommissioned well. If these fluids were not prevented from moving up the well they could potentially leak to the surface or flow into other strata (if there was also a failure in the casing and cement sheath allowing fluids to flow from the interior of the well to the surrounding formation) (Liversidge et al., 2006). The cement plugs are designed to be impermeable to fluid flow and long-lasting, however, plug integrity in decommissioned wells is considered a possible formation fluid leakage pathway (Ford et al., 2017).

Cement plugs in decommissioned wells are exposed to axial loads from fluids in the well, pore fluid pressures, and reservoir movement (Akgün & Daemen, 1999; Mainguy et al., 2007). These loads can induce shear stresses along the interface of the plug and host casing or rock potentially resulting in cracking and increased permeability at the interface or under extreme condition may cause the plug to unload or to slip (Akgün & Daemen, 1999).

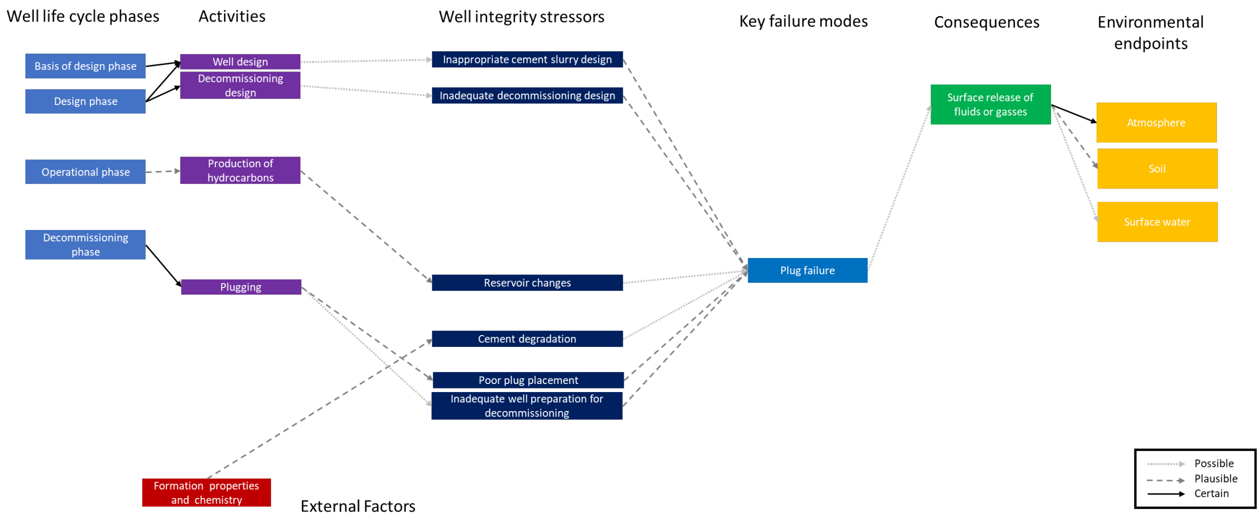

Figure 10: Subsection of the causal network associated with the plug failure mode.

The integrity of decommissioned wells is highly dependent on the integrity of the reservoir zone isolation plug and production casing plug. If the integrity of the reservoir plug and the production casing plug were to become compromised, it could lead to the movement of pore fluids to different strata. The isolation of the surface casing and the potential creation of a leakage path through the surface casing shoe often relies on the reservoir zone isolation plug and production casing plug.

A leakage path through the reservoir zone isolation plug can may also be created if there was a pore fluid pressure build-up or pressurisation from nearby production wells (Babaleye et al., 2019).

Monitoring of plug failure

Positive and negative pressure testing evaluates the performance of each cement plug as the wellbore is sealed. During stage 1 decommissioning in the NT, GM (gas migration) and SCVF (surface-casing vent flow) checks can be used to monitor for any leaks through the reservoir plug while the wellhead remains in place. The integrity of the reservoir plug is of utmost importance to prevent the movement of hydrocarbon or other fluids inside the well.

Therefore, subsurface monitoring approaches (presented in section 4.2) can be employed to closely monitor the integrity of these plugs. The final plug installed in decommissioned wells is the surface plug. The integrity of the surface plug should be maintained to avoid the creation of leakage pathways. The surface monitoring approaches (section 4.3) and indirect monitoring approaches (section 4.4) can be undertaken to achieve this purpose.

3.4.4 Surface Equipment Failure

Surface Equipment failure description

The wellhead and surface pressure equipment (also referred to as a Christmas tree) play an important function in controlling the well flow and containing downhole pressures. It is critical to ensure the integrity of these surface equipment valves and seals to prevent leakage of fluids to the surrounding environment (Al-Ashhab et al., 2004). The wellhead infrastructure is susceptible to a range of failures from small leaks from valves and fittings through to fatigue failure, which may result in significant compromises to surface equipment integrity and even catastrophic accidents (Chang et al., 2019).

The chances of significant surface equipment failure are considered to be low. A more common occurrence is minor surface equipment integrity failure from leaky seals which isolates the top of tubulars, seals between hangers, valves and failed gaskets. Failure of surface equipment is usually easy to detect. The complexity of repairs to surface equipment is depenant on if downhole isolation is required, however, some minor repairs to surface equipment can be made without expending a significant cost (King & King, 2013; King & Valencia, 2014) including damage to the wellhead parts , wellhead corrosion (Abreu et al., 2019).

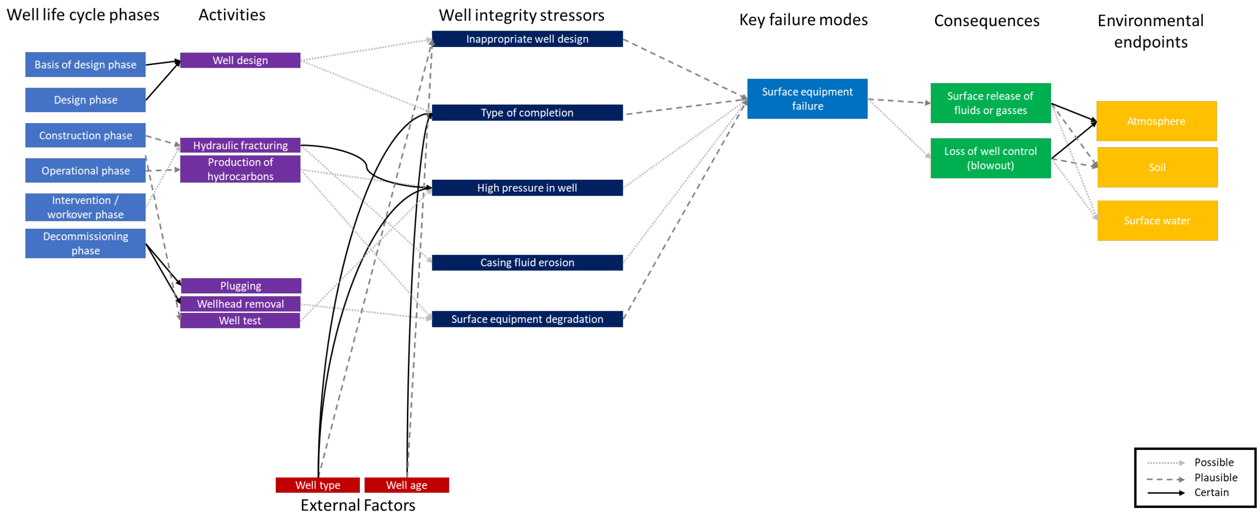

Figure 11: Subsection of the causal network associated with the surface equipment failure mode.

Monitoring of Surface Equipment failure

The well surface equipment including wellheads and Christmas trees require monitoring for corrosion, functionality, and integrity for operational purposes and also to increase the lifetime of wellhead equipment. The failure of surface equipment (i.e. gaskets and valves) is relatively easy to detect through regular inspection and surface leak monitoring. It is also relatively easy to undertake minot repairs to surface equipment. However if repairs which involve downhole isolation are required, the cost and time involved will be significantly higher.

3.4.5 Cement bond failure (Creation of micro-annuli)

Cement bond failure description

Micro-annuli are tiny gaps created if the interface between the cement sheath and the steel casing or the cement sheath and the surrounding rock formation become debonded . Debonding of these cement sheath bonds with the casing or the formation are considered to be a potential source of well integrity failure (Lecampion et al., 2013).

Creation of micro-annuli can occur due to many factors including but not limited to: deterioration of cement bond strength, poor removal of the mud cake created during drilling, wellbore de-pressurisation, injection of cold water (lowering temperature in a well), casing mechanical failure, perforation operations, cement shrinkage, and cement mechanical failure (Dusseault et al., 2000)(Lecampion et al., 2011). The degree of adherence or bonding is also dependent on the formation surface properties (Van Der Tuuk Opedal et al., 2013).

Bond failure risk assessment

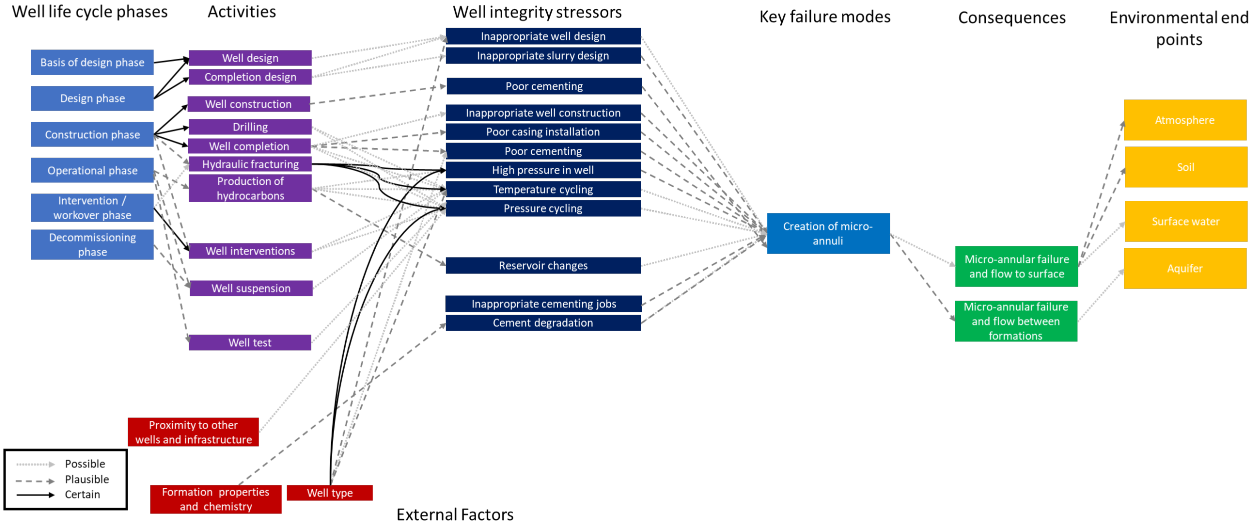

Figure 12: Subsection of the causal network associated with the creation of micro-annuli failure mode.

The micro-annuli may extend between permeable layers (strata) or to the surface if the driving forces (pressure gradient, fluid buoyancy, etc) are sufficient. Therefore the micro-annuli could act as a potential pathway for formation fluid movement between subsurface layers or to the surface.

Monitoring of cement bond failure

Monitoring of annulus pressures would take place throughout the well lifecycle. Prior to decommissioning, monitoring of the annulus pressure would be undertaken as part of the operators' annulus pressure management program. These readings may provide an indication of downhole barrier degradation (potential cement bond failure). These and other monitoring approaches are most readily undertaken prior to beginning the decommissioning process (before the placement of the cement plugs in the well) as, at this stage, a down-hole tool can be used to conduct a cement bond log.

After cement plugs have been placed in the well but before the wellhead is removed, annular pressure can be monitored to check for hydraulic connection to the surface along cement bond failure pathways. However, monitoring of surface annular pressures does not directly monitor for cement bond failure and would not capture cement bond failure or fluid movement between subsurface layers.

After the wellhead has been removed and the surrounding surface area remediated, only indirect monitoring methods could detect leaks from cement bond failures. It would be very difficult to determine the cause of these leaks and assign them to cement bond failure compared to other potential failure modes. Improving knowledge on reducing well integrity failures would be limited at this point in time.

4 Well integrity monitoring for decommissioned wells

Well integrity monitoring by the petroleum industry typically follows a risk based approach, where the monitoring methods are selected in accordance with the risks to well integrity identified for the well (International Organization for Standardization, 2017; Standards Norway, 2021). The objective of this monitoring is to avoid well integrity failures by ensuring that the well stays within operating limits, including monitoring the condition of well barrier elements.

For decommissioned wells, direct monitoring of well barrier elements will be challenging as access to the well is limited or not possible. Maintaining long term access to the well defeats the objective of well decommissioning, which is to completely remove the well from service along with any surface expression.

The following section looks at the current options available for monitoring of decommissioned wells, starting at the time of decommissioning and then into the long term. The key failure modes identified in section 3 are used to provide context.

What monitoring techniques are available for decommissioned onshore wells in the Northern Territory?

Onshore petroleum wells in the Northern Territory are decommissioned in a two-stage process. The first stage of decommissioning involves installation of cement plugs across hydrocarbon bearing zones and aquifers while the second stage involves removal of the wellhead and installation of the surface plug (Northern Territory Government, 2019). As a well progresses through the decommissioning process and access to the well is removed, the available options for monitoring the integrity of the well reduce proportionally.

Prior to the installation of cement plugs in the first stage of decommissioning (Figure 18: Preparing for decommissioning) the entire well is accessible and therefore the full suite of monitoring techniques are able to be used.

Once cement plugs have been installed across the hydrocarbon bearing zones and aquifers (Figure 18: After plug installation) the interior of the well is only accessible to monitoring tools to the top of the shallowest cement plug. The section of the well below the top of the shallowest cement plug is inaccessible to monitoring tools as it has been sealed by the cement plug. At this point in the decommissioning process (after stage 1 but before stage 2) it is still possible to monitor the annular pressures at the surface and the performance of the shallowest cement plug and any monitoring equipment that has already been installed in the well including pressure gauges, fibre optics etc.

After the wellhead is removed, the surface plug installed and the well cut and buried below the surface in stage 2 (Figure 18: After wellhead removal), the monitoring options are drastically reduced as the well is no longer accessible to downhole tools and the annular pressures are no longer able to be monitored. At this stage monitoring is restricted to indirect techniques such as groundwater, atmospheric and soil sampling, and visual inspection of the rehabilitated wellpad.

There has been a considerable amount of research around long term monitoring of well integrity in the context of geological storage of carbon dioxide (Jenkins, 2020b; e.g. Rütters et al., 2013). In this context, well integrity is considered as part of the overall monitoring and verification of storage performance. This literature draws on the experience of the petroleum sector. A significant amount of carbon dioxide storage is conducted through enhanced oil recovery operations, where carbon dioxide is injected into the subsurface to drive petroleum production. Abandoned petroleum wells have been identified as a risk for carbon dioxide leakage in these operations, however this risk has been evaluated to be low due to the integrity of these wells (Jenkins, 2020b).

Some of the surface monitoring strategies for geological carbon storage (Jenkins, 2020a), particularly those that look for evidence of leakage of gas, may have application for decommissioned petroleum wells.

4.1 Well monitoring objectives

Well integrity monitoring for decommissioned wells has two broad objectives. The first is to monitor the well barrier components to confirm that they are meeting their performance criteria and are not degrading. This form of monitoring allows the detection of potential well integrity issues before a well integrity failure occurs so that remedial action can be taken. For a decommissioned well, the barrier components identified in the five failure modes described in section 3.4 are the most important. They are the cement sheath (annular cement), casing, plugs, the bond between cement and the formation or casing, and any surface equipment that remains on the well.

The second objective is to monitor for the consequences of breaches of well integrity that have led to a release of fluids from the well. As outlined in section 3.2.1, a well integrity failure may lead to the release of fluids to the environment. These fluids could be hydrocarbon gas (predominantly methane), hydrocarbon liquids and saline groundwater. Monitoring of environmental endpoints, including the atmosphere, soil, surface water and groundwater for the presence of these fluids may allow the presence of a well leak to be discovered. They are unlikely to allow the nature of the leak to be determined.

The timeframe for monitoring decommissioned wells is also unconstrained. The aim of decommissioning is to ensure well integrity “permanently” (Northern Territory Government, 2019). It has obviously not been possible to demonstrate technologies for monitoring of wells beyond a few decades, and there are few environmental monitoring approaches (aside basic observations) that extend beyond a century. The Pepper Inquiry recommendation 5.2 is for companies to monitor wells for a period of time to demonstrate that a decommissioned well has an acceptable level of integrity (Pepper et al., 2018). The recommendation for a monitoring program by the regulator for wells once relinquished did not state a timeframe.

The range of monitoring techniques applicable to decommissioned wells are limited compared to those available for operational wells or wells under construction due to the inability to access the well once plugs are set within the well and surface access removed (through removal of the wellhead, sealing and burial of the wellhead). Monitoring methods can be grouped by access to the well (Figure 13) as follows:

- Direct subsurface monitoring of the well (Section 4.2)
- Direct surface monitoring of the well (Section 4.3); and
- Indirect monitoring (Section 4.4).

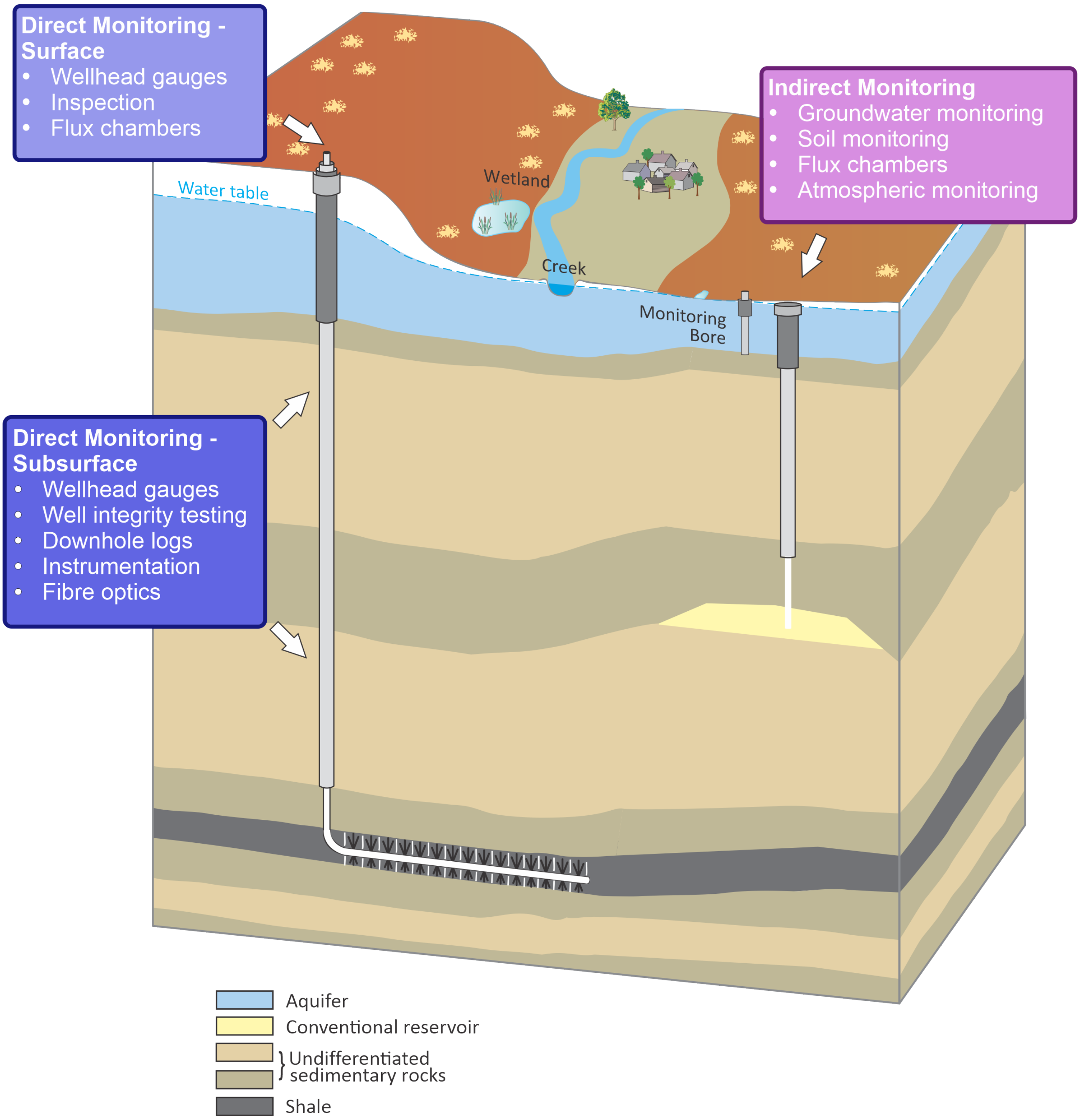

Figure 13 - Common monitoring approaches applicable to operaitonal wells (left-top and left-bottom) and decomissioned wells (right)

4.2 Direct monitoring – subsurface

The integrity of a petroleum well is monitored throughout their lifecycle as part of well integrity management. This is a regulatory requirement in The Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) as well as a requirement in a number of industry standards (International Organization for Standardization, 2017; Standards Norway, 2021). Relevant monitoring parameters include, but are not limited to well pressures, production flow parameters, barrier performance, corrosion and erosion rates, and leak detection (Berge, 2017). There are direct subsurface monitoring methods that can be used to detect signs of fluid movement as a result of well integrity issues. The monitoring methods applied require access to the well and can be conducted as long as the well is still accessible.

There are some techniques where sensors could be permanently installed in the well to provide ongoing data however these are not common as surface remediation is not possible while maintaining a link to the sensors. Other concerns with embedding permanent sensors into well barrier components is that the sensors themselves may reduce the integrity of the well barrier and the longevity and utility of such sensors is not proven. The durability of downhole equipment, including sensors, fibre optic and electrical cables for very long term monitoring (decades to centuries) may also prove to be challenging.

The Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) requires wells to be decommissioned in a two stage process. The first stage involves verifying well integrity and setting plugs in the deeper section of the well. The wellhead is left in place to allow monitoring of the well and the performance of the plugs and other well barrier elements. Once the performance of the first stage decommissioning has been validated, the final plugs can be set in the well, the wellhead removed, casing cut off and the well capped below ground level. The monitoring methods described below will be most applicable:

- verify well integrity immediately prior to decommissioning;
- verify well barrier elements installed as part of the decommissioning operations and their performance after first stage decommissioning is completed; and
- to detect evidence of fluid movement along the well after the first stage of decommissioning, or after the second stage where access to the well is maintained to allow data collection.

4.2.1 Monitoring of well barrier element condition

Monitoring of well barrier element condition is most valuable prior to decommissioning as it allows their integrity to be confirmed or, if problems are identified, for remedial action to be conducted while the well is still accessible.

Downhole (wireline) logging tools

In the preparation for decommissioning down-hole logging tools can be utilised to inspect the well components. There are a variety of downhole logging tools available for well integrity monitoring and there is considerable ongoing development. Logging tools are available to evaluate the condition of well barrier components, primarily the cement sheath and casing.

Logging tools for casing allow the thickness, level of corrosion, deformation and any scale build up to be determined. These tools include:

- optical image logs of the inner casing surface (requires well fluid to be clear),

- cased hole multifinger calliper logs that measure the inside or casing and can detect deformation or erosion of casing,
- ultrasonic casing evaluation logs that detect deformation, thinning and pitting,
- magnetic and electromagnetic logging tools that allow casing corrosion and thinning to be detected.

Logging tools for the cement and the bond between cement and formation that allow the condition of the cement and bonds to be determined. These tools include:

- cement bond logs (CBL), which use sonic techniques to evaluate the bond between cement and casing, cement and formation (Bellabarba et al., 2008).
- ultrasonic logs and enhanced ultrasonic logs, which are similar to CBL, for the evaluation of cement quality (Bellabarba et al., 2008; Timonin et al., 2014).

After the installation of reservoir plugs, downhole logs can only be run as far as the installed cement plug. Once the wellhead has been removed and the metal plate welded to the surface casing it is no longer possible to run downhole logs.

Well integrity testing

The integrity of well barrier components can be tested, typically by applying loads (positive or negative pressure) to the well or well components. International standards such as the *NORSOK D-010 Well integrity in drilling and well operations* (Standards Norway, 2021) set out requirements for well integrity testing at various stages of a well's lifecycle and the Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) requires well integrity to be verified at all times, including during decommissioning. Well barrier tests can include:

- pressure testing of the well to verify integrity of well barrier envelope, including casing, packers, casing shoes and plugs set in the well. These tests involve pressurising the well for a period of time and monitoring for pressure drops that may indicate leakage.
- "tagging" cement plugs placed in the well, which involves loading the cement plug with the drill string.
- vertical interference tests, which measure the isolation between two intervals by applying pressure in one and measuring the transient response in the other (Gasda et al., 2013).

Well integrity testing can be combined with well logging to obtain additional data about well barrier components. For example, "pressure pass" CBL or ultrasonic logs are run with the well pressureised, which can assist with the detection of micro-annuli (Saini et al., 2021; Timonin et al., 2014)

4.2.2 Monitoring to detect evidence of fluid movement

Direct monitoring of the subsurface components of a well for evidence of fluid movement along a well allows the consequences of a well integrity failure to be detected. The characteristics that can be measured are:

- pressure that can indicate connectivity between zones,
- sound that can indicate fluid movement,
- temperature that can indicate fluid movement,
- composition of fluids that can indicate contamination due to fluid movement.

Wellhead pressure gauges / sensors

Each of the annuli between the layers of casing and cement terminate at the surface expression of the subsurface component of the well. Pressure gauges and sensors are installed to monitor for pressure changes in any of these annuli. Pressure build-up or changes in these annuli could indicate gas migration caused by failure of the well components.

Monitoring of these pressures over time gives operators guidance on the integrity of the well. They are a key component of the monitoring conducted in a two stage decommissioning process. Monitoring of wellhead pressures is routine and the data is suitable for telemetry for remote monitoring. Once the wellhead is removed and the metal plate welded to the surface casing, it is no longer possible to monitor these annuli for pressure changes.

Annular gas composition analysis

Gas from the different well annuli can be collected from the surface equipment and analysed for composition (thermogenic vs biogenic) to gain insight on the origin of any gas leakage point using the techniques described in section 4.3.3 Flux chamber methane monitoring.

Downhole (wireline) logging tools

Advanced logs which can detect unintended fluid flow behind the casing may be run if well integrity problems are suspected. Temperature logs can be used to detect changes in the thermal gradient along a well that may indicate heat convection due to fluid movement. Acoustic or microseismic monitoring logs and sensors can be used to detect the sound or vibrations made by fluid movement, including gas bubbles.

Fiber Optic and Distributed Sensors

Distributed fibre optic sensing methods are receiving a considerable amount of attention as important tools for monitoring and surveillance of oil and natural gas fields. They involve the installation of a fibre optic cable within the well that is interrogated with an instrument at the surface. DFOS methods can be used to measure temperature, strain and acoustic/seismic signals along the well. All fibre-optic sensing methods operate on similar principles. The interrogator sends a laser pulse sent down the cable and records the light reflected back to the analyser from the cable. The travel time is used to determine the location of a given measurement on the fibre. The character and the magnitude of the reflected light is analysed to obtain temperature, acoustic or strain data at the located depth.

The installation of the fibre-optic cable can be done as part of the well construction process, where it is typically attached to the outside of casing (and subsequently encased in the cement sheath). A fibre optic cable can also be installed as part of a well completion on tubing, or during the plugging of a well, or simply lowered into the well for short-duration surveys.

There are challenges associated with deploying these systems including the placement and configuration of the fibre optic cable for the site-specific well and formation conditions and the need to have an analyser at the surface. The analysers are complex, generate large amounts of data that requires processing and interpretation. Long-term monitoring would develop large datasets that would need to be managed (Sun et al., 2021).

Distributed Temperature Sensing (DTS)

DTS technology consists of fibre optic cables as temperature sensors. DTS typically provides temperate measurements at 1-m spacing along the entire cable (Mawalkar et al., 2019). The resolution DTS allows it to detect very small magnitudes of temperature variations (in the order of 0.01 °C). Similarly to more traditional temperature logging, anomalies in the thermal gradient along a well may indicate heat convection due to fluid movement. Temperature changes during the placement of the cement sheath or cement plugs might provide useful information for verifying well integrity.

Distributed Accoustic Sensing (DAS)

DAS technology consists of a fibre optic cable as an acoustic or vibration sensor, which can also be used to to detect strain (Li et al., 2022; Raab et al., 2019). Data collected by a DAS system may allow annular leak detection, evaluation of the cement-casing or cement-formation bond, and assessing the impacts of far-field stresses on the well (Li et al., 2022). DAS can provide data throughout the well's lifecycle related to well integrity including information about the emplacement of the cement sheath or cement plugs. An emerging application of DAS is to coat the cable with polymers that swell when exposed to certain fluid compositions, producing strain in the cable. This could potentially be a useful means of detecting fluid movement behind casing.

Application of DAS has yet to become routine, and is still in the technology development phase. Considerable effort is required to understand the data that is collected. The application of DAS to long-term well integrity monitoring is feasible but has not been demonstrated. DAS collects data at rates of over 20 MB/s creating significant data management and data processing issues.

Real-time Compaction Imager (RTCI)

Subsurface geo-mechanical stresses can instigate formation faults, slippage, and compaction which may lead to well failures. Compaction may occur as the results of increasing the formation density due to production operations (which can originate shifting in the formation layers or moving laterally on the boundary lines) and can cause significant damage to wells including buckling, bending, crushing and shearing of the casing (Earles et al., 2011).

The Real-time Compaction Imager (RTCI) system has been introduced as a powerful tool to replace radioactive tag logging and multi-finger or acoustic callipers. The system consists of a specific fibre optic including many closely spaced Fibre Bragg-grating (FBG) strain gauges which is wrapped around the wellbore tubular. The strains along the wellbore tubular are recorded and by utilizing an inversion algorithm the RTCI system portrays three-dimensional images of the well deformation.

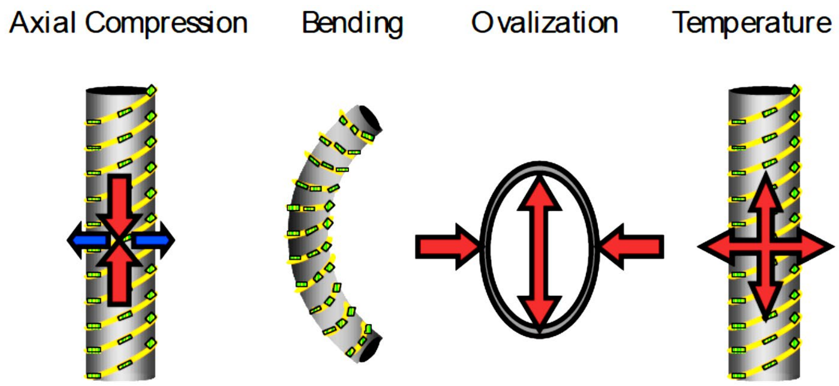

Figure 14: Three modes of wellbore deformation after (Pearce et al., 2009; Earles et al., 2011)

One of the advantages of deploying this system is that there is no need for well intervention, and it can be permanently installed during completion procedures. Deploying this system allows to monitor the well constantly and results in early detections of strains and potential damages. The other advantage is the system capability to capture four modes of wellbore deformation owing to warping the optical fibre around a wellbore tubular at a fixed angle as shown in Figure 14 including (Earles et al., 2011; Pearce et al., 2009):

- Axial Strain (either at compression or tension) associated by upward or downward movements
- Bending which shows as sinusoidal signal coincident with the wrap angle
- Ovalization which appears as positive and negative strain around the fibre express tube
- Temperature induced thermal strains which appears as a uniform proportional shift up or down, similar to axial compression

Distributed Temperature and Strain Sensing (DTSS)

DTSS combines temperature and strain measurements can be utilised to monitor casing deformations, cement integrity, and zonal isolation (Wu et al., 2017, 2019a, 2019b).

The system consists of two dedicated fibre optic cables in which the first one measures the strain evolution due to the casing deformations and the second one is coated with a hydrocarbon-sensitive polymer to sense additional deformations stemming from the presence of hydrocarbon and losing zonal isolation (i.e. DTSS system can capture strains at the interface of the cement with casing). The temperature changes resulting from formation fluid invasion into the cement annulus can also be detected by the system (Wu et al., 2017, 2019b, 2019a).

Furthermore, DTS and FBG can provide information pertaining to the deformations behind casing which can also help detecting the leakage pathways to the surface due to employing (Mao et al., 2017) a configurator software which displays depth vs. temperature data at the given intervals.

4.3 Direct monitoring – surface

Direct surface monitoring is limited to observations made at the surface location of the well (either at a wellhead if it is still in place or within a few metres of the surface location of the well). Surface measurements are the primary option for monitoring decommissioned wells owing to the fact that access to the well is limited. Surface monitoring cannot be used to monitor the status of well barrier components (aside from a wellhead) and can only be used to detect the presence of a a fluid leak. Methane is the most abundant gas in hydrocarbon bearing formations and is likely to be the first indication of a well integrity issue due to its buoyancy. Most of the surface monitoring methods involve the detection of methane.

Measurements made from wellhead gauges/sensors are considered to be direct monitoring of the subsurface as they are measuring subsurface parameters.

4.3.1 Surface equipment inspection

The most basic form of monitoring is a visual inspection of surface equipment including wellheads or the surface location of the well. Indications of a leak could include the presence of liquid hydrocarbons or water, gas (bubbling through water) or other anomalies that may be associated with a leak such as changes to vegetation.

If a well head is present, it can be inspected for corrosion, functionality, and integrity (leaks) for operational and compliance purposes. Surface equipment failures (i.e. gaskets and valves) are relatively easy to detect and rectify compared to subsurface integrity failures.

4.3.2 Surficial methane scanning

Testing for the presence of methane in the air immediately above the soil/air interface using portable methane detection instruments is the simplest form of monitoring (Schout et al., 2019). The presence of methane above background levels may provide evidence of a leak that is reaching the surface. These instruments measure concentration and additional measurements would be need to determine leakage rates.

The atmosphere contains approximately 1.8 ppm methane, however natural and anthropogenic factors can influence local concentrations (Day et al., 2015; Ong et al., 2019). These can include biogenic sources of methane such as microbial activity in soil or groundwater, termite mounds and cattle. Atmospheric conditions can affect concentrations by influencing rates of exchange with soil and dilution of sources due to wind. Measurement protocols need to take these sources in to account. The level of methane that constitutes an anomaly should be assessed on a case by case basis. A small anomaly that is closely associated with a decommissioned well is likely to be more significant indicator than a diffuse anomaly.

There are a number of technologies available for portable methane detectors that are capable of measuring methane concentrations at atmospheric levels and recent reviews highlight the capabilities and ongoing developments (Aldhafeeri et al., 2020; Fox et al., 2019). The majority of instruments that are suitable for field surveys rely on optical methods and include cavity ring-down spectroscopy and laser absorption spectroscopy. There is a trade off between sensitivity and ease of use with these instruments, however the technology is rapidly evolving.

It is important to note that the presence of a methane at the surface does not necessarily indicate a well leak. Further investigation is required to characterise the source of the anomaly. Schoult et al (2019) also demonstrated that the absence of an anomaly at the surface does not rule out a well leak as processes in soil may consume methane before it reaches the surface. In these cases any leak is likely to be small.

4.3.3 Flux chamber methane monitoring

Flux chambers consist of a sampling chamber that allows the concentration of gasses within a defined volume to be measured. They may be used at the soil surface, or embedded within the soil profile. Detection of a methane anomaly at the soil-atmosphere interface does not allow the flow rate of methane to be determined. Methane flow rates can be measured using flux chambers which can be installed either at the surface or 1m deep into the soil (Boothroyd et al., 2016; Day et al., 2015; Lyman et al., 2017; Schout et al., 2019). Embedding chambers within the soil profile may detect leaks where microbial activity in the soil profile consumes methane (see section 4.4.3 for further discussion on monitoring methane in soil or at the ground surface).

The mass flow rate into a flux chamber is calculated using linear regression on the concentration against time data as shown in equation (1):

$$F = \frac{dC}{dt.V} \tag{1}$$

where F is the $\mathrm{CH_4}$ flow rate (mg $\mathrm{hr^{-1}}$), dC/dt is the rate of change in methane concentration in the chamber (mg $\mathrm{cm^{-3}h^{-1}}$) and V is the chamber volume ($\mathrm{cm^{-3}}$) (Schout et al., 2019).

This method may not be able to determine the origin of the leakage point and further analyses is required to differentiate between biogenic or thermogenic origin (Day et al., 2015; Schout et al., 2019). Gases in conventional or shale petroleum resources originate from thermogenic processes. Thermogenic methane has a different isotopic signature to biogenic methane and will often be associated with heavy hydrocarbon gasses such as ethane, propane and butane. Newer sampling methods, such as cavity ring down spectrometry, are able to analyse a number of hydrocarbon gasses and conduct isotopic analyses (Ong et al., 2019) and could be used along with flux chambers to characterise the gas to assist in determining its source. The efficiency of surface monitoring technologies is complicated by the lack of intact wellhead, poor resolution, being labour-intensive and complex data processing (Feitz et al., 2014; Schout et al., 2019).

Day et al (2015) provide an example of using flux chambers to measure methane emissions from a legacy coal exploration bore in the Surat Basin, including an analysis of the gas composition and its likely origins.

4.4 Indirect monitoring

Indirect monitoring methods involve observations taken of the environmental receptors (groundwater, surface water, soil and air) in the vicinity of a decommissioned well. Monitoring technologies include shallow groundwater monitoring, surface water monitoring, soil gas sampling, soil flux, atmospheric monitoring, surficial scanning, and static chamber measurements. There is considerable overlap between the requirements for monitoring of petroleum wells and those for geological carbon dioxide storages (Feitz et al., 2014; Jenkins, 2020b, 2020a). These monitoring methods can look directly for fluid that has leaked from a well (methane gas, liquid hydrocarbons or saline groundwater) or indicators of these fluids (changes to the environment).

4.4.1 Groundwater monitoring

Methane monitoring

Measuring the concentration of dissolved gases in groundwater is an indirect monitoring of gas leakage. Monitoring groundwater for methane (along with other hydrocarbons associated with gas resources) is restricted to the analyses of groundwater samples. *In-situ* monitoring for dissolved gas is not currently possible. There is a considerable amount of literature on methods for sampling and analysing groundwater for methane and its application to detecting gas leaks from petroleum activities (Boothroyd et al., 2016; Jackson et al., 2013; McMahon et al., 2018; Roy et al., 2022). The UK's Environment Agency (2021) and Walker and Mallants (2014) provide reviews of methodologies for sampling methane in groundwater and water bores respectively. All of these studies highlight the challenges in measuring and attributing sources of methane in groundwater.

Methane can occur in groundwater as a result of biological processes, and can also be consumed by chemical and biological processes. Roy et al (2022) provides a good overview of these processes in the context of groundwater methane monitoring. Monitoring groundwater for methane needs to take into account background levels and be able to determine sources of methane within the groundwater. Time-series data that allow changes to be detected are likely to be most effective in detecting a leak (McMahon et al., 2018; Roy et al., 2022). The location of monitoring bores in relation to decommissioned wells needs to consider the depth of aquifers and directions of flow within the aquifer. The accuracy of this method also significantly relies on the distance between the leakage point and the location of groundwater sampling (Jackson et al., 2013), the direction and velocity of groundwater flow and microbial methane oxidation occurrence (Schout et al., 2019).

The Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) has requirements for groundwater monitoring bores to be installed at well pads where hydraulic fracturing activities are planned. The characteristics of aquifers and groundwater flow directions must be considered when selecting sites for the monitoring bores. The Code also requires groundwater to be analysed for methane, ethane and propane along with a range of other organic and inorganic analytes. The code does not require these monitoring bores to be maintained post well decommissioning. The data collected by these wells will provide baseline information on water quality and the presence of methane.

Monitoring the concentration of methane in groundwater may be able to provide an indication of a methane leak from a decommissioned well. If methane is detected in groundwater further investigation is likely to be required to characterise the source of the gas. Analyses of the isotopic composition of methane can be used to distinguish between thermogenic and anthropogenic sources. Analyses of groundwater for other compounds, including hydrocarbons, also provide important observations when evaluating the source of methane.

In-situ monitoring of dissolved methane composition is not currently possible and proxy methods have been considered using total dissolved gas pressure (Roy et al., 2022). The likely leakage rated from decommissioned wells may be too low to cause changes in total dissolved gas pressure in aquifers that can be differentiated from natural processes.

Other contaminants

Groundwater monitoring can also be used to detect changes to physical parameters such as pH and electrical conductivity and inorganic components. These characteristics could provide an indication of movement of saline groundwater along a decommissioned well. Baseline data will be important for detecting small changes in concentration of these components, and the Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) has a list of analytes for groundwater monitoring at well pads where hydraulic fracturing is planned that includes physical characteristics and inorganic components. Some of these parameters (pH and electrical conductivity) are ameanable to continuous monitoring.

As for monitoring for methane in groundwater, the location of monitoring bores relative to the decommissioned well will be important and would need to take into account the flow direction of groundwater.

Any change in groundwater chemistry is likely to require further investigation to determine the source of contaminants. These could include the application of environmental tracers, which are routinely used for investigating inter-aquifer connectivity due to natural processes (e.g. Priestley et al., 2017) and in gas development areas (Banks et al., 2019; Suckow et al., 2020).

Geophysical methods

Geophysical methods that are based on the way the earth responds to an applied or natural electromagnetic fields (Jordan & Hare, 2002) may have an application in detecting brine plumes or fluid leakage from wells due to changes in the electrical conductivity of an impacted groundwater body. These methods are generally complicated to deploy and would have more application in the investigation of a known leak rather than as a means of detecting one.

4.4.2 Surface water monitoring

Surface water monitoring for evidence of methane or other contaminants is unlikely to be practical for monitoring of decommissioned wells. Any contaminants would need to pass through groundwater and soil, which are better targets for monitoring. There are likely to be confounding factors for surface water monitoring involving other potential sources of contamination.

4.4.3 Soil Monitoring

Soil gas refers to gas within the vapour space in soil within the vadose zone (the part of the soil between the ground surface and the water table). Soil gas can be monitored for changes in the concentration of methane. For indirect monitoring, soil gas sampling is applied over a broader area than immediately above the location of the well.

Soil gas sampling is routinely applied at landfills and other methane sources, including reclaimed wetlands, and there are regulatory guidelines in many jurisdictions (EPA Victoria, 2018; NSW Environmental Protection Agency, 2020). These sources tend to have higher methane fluxes than would be expected from a decommissioned well. However they do provide examples of how samples of soil gas can be collected for analyses for methane. Gas samples could be further analysed (isotopes, presence of other hydrocarbons) to determine the source of gas.

Flux chambers can be used to monitor the flux of soil from the soil surface to (and from) the atmosphere and are discussed in section 4.3.3. Similar techniques can be applied to sampling from within the soil profile, where probes are used to extract gas from the soil. Examples include the use of simple tubes (Ilie & Vaccaro, 2020) and novel diffusive probes (Roscioli et al., 2021). These novel methods are likely to require refinement before they can be considered for routine monitoring. Sampling from within the soil profile addresses a potential issue for near-surface monitoring where methane oxidation or microbial degradation of methane in the unsaturated areas leads to reducing methane emissions from soil. Studies have found that the application of surficial measurements and static chambers installed at the surface may not detect leaking gas due to these processes (Lyman et al., 2017; McMahon et al., 2018; Schout et al., 2019). These studies found that installing the static chambers about 1m deep into the soil can be an effective method as the measured flow rates are larger at deeper locations comparing to the surface.

An emerging area for detecting methane in soil is the use of microbial markers, which involves analysing the soil microbiome for an increase in the abundance of methanogenic microbes. Observations from significant gas leaks or offshore well blowouts has demonstrated that microbial assemblages can change in response to the presence of hydrocarbons associated with gas leaks related to gas storage or production (Crespo-Medina et al., 2014; Tavormina et al., 2016; Wolfe & Wilkin, 2017) and from natural sourecs (Katayama et al., 2008).

4.4.4 Atmospheric monitoring

Indirect atmospheric monitoring can detect changes in the background concentration of methane, and this approach is routinely applied to investigate fugitive emissions from natural gas development (Day et al., 2015; Ong et al., 2019). There are a range of monitoring technologies that can be used and a comparison of their ability to detect and quantify methane emissions. Feitz et al (2018) conducted experiments on gas methane and carbon dioxide gas detection using a range of methods, including commercially available instruments, and found that emissions to air of the magnitude of 2,500 CH_4 kg/year were easily achieved. These experiments were conducted with the sampling equipment approximately 30 m from a known source location. In the application to decommissioned wells, they may not offer a significant advantage to direct monitoring at the surface location of a well (see section 4.3.2 and 4.3.3).

Airborne and satellite based methane sensing technology is under continued development, however their detection limits are likely to be too high to be useful form monitoring decommissioned wells. Detection limits for point source emissions from current satellites are around one to two million CH_4 kg/year, while airborne platforms may be able to detect sources from 17,000 CH_4 kg/year (Fox et al., 2019; Jervis et al., 2021). Geostationary satellites may make significant improvements as they can measure for sustained periods, however these satellites are still in development (Jacob et al., 2016). Recently data from the WorldView 3 satellite have been used to detect methane leaks from a pipeline with a flow rate of 876,000 kg/year at a high spatial resolution (Sánchez-García et al., 2021).

5 Well decommissioning and remediation

What decommissioning and remediation techniques are available for onshore wells in the Northern Territory?

The primary technique used to decommission wells in the Northern Territory is the installation of downhole barriers (plugs) which fill and seal the centre of the well and provide zonal isolation across hydrocarbon bearing zones, aquifers and to seal the final section of the well near the surface. The code stipulates that these downhole barriers (plugs) be constructed out of cement (Code of Practice of Northern Territory Government, 2019) and requirements for test cement and plugs.

Remediation techniques and technologies are not specifically stipulated in the Code however the performance requirements of any remediation are stipulated. Common compromised well integrity remediation techniques include: perforating casing and squeezing cement to fill in failed or absent sections of cement sheath, drilling out and re-installing failed cement plugs, and installation of casing patches over failed sections of steel casing. All of these approaches require access to the well.

Emerging technologies have the potential to improve the performance of both decommissioning and remediation techniques. Such emerging technologies utilise alternative materials and techniques to achieve a well integrity seal which potentially lasts longer and/or is more versatile than the current cement and steel based technologies.

Remediation of well integrity issues is complex once a well has been decommissioned. Access to the well needs to be re-established and there are significant risks associated with this activity. Remediation of any well integrity issues immediately prior to decommissioning can make use of routine operations and is preferred.

5.1 The decommissioning processes

The decommissioning phase is the final phase in the well life cycle; in this phase, the wells are decommissioned, plugged and abandoned. The aims of decommissioning are to (International Organization for Standardization, 2017):

- prevent release of formation fluids or well fluids to the environment (including aquifers);
- prevent the flow of groundwater or hydrocarbons between different layers of rock; and
- isolate any hazardous materials left in the well.

These aims must be met in perpetuity. It is difficult to define perpetuity in a meaningful way but it is likely to be significantly longer than a human lifetime and of similar duration to geological processes. The method of plugging and abandoning a well involves confirming the well's integrity to ensure that there will be no movement of fluid into or out of the well or along the well, and placing barriers in the well to prevent the movement of fluids within the well. A schematic of an decomissioned well is shown in Figure 15. The plugs typically comprise cement with mechanical plugs or retainers. To provide long-term integrity, the cement (or other barriers material) must:

- not shrink;
- be able to withstand the stresses in the wellbore;
- be impermeable;
- be impervious to chemical attack from formation fluids and gases;
- be able to bond with steel casing and rock; and
- not cause damage to the casing.

The design of well decommissioning must be considered during the design phase of the well. For example, the casing material that will be left in the well must be compatible with the objectives of decommissioning.

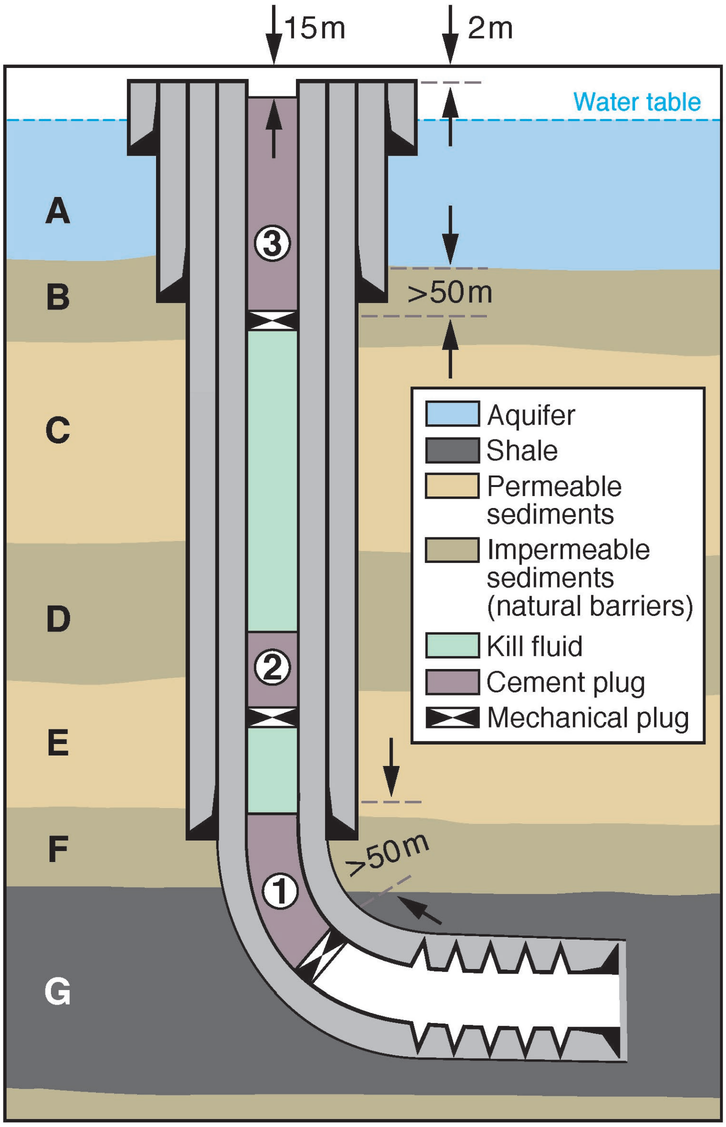

Figure 15: An abandoned well, showing the cement plugs that are placed in the well to prevent vertical flow of fluids. Numbers indicate order of placement of the cement plugs. Not to scale. From (Huddlestone-Holmes et al., 2017).

Once a well has been decommissioned, the well is essentially sealed at the surface and there is little prospect of re-using (or re-entering via downhole tools) the well for any purpose. Monitoring may be conducted during the well decommissioning process to confirm that plugs have been properly set in the well. However the well's ongoing integrity should not be dependent on long-term monitoring (International Organization for Standardization, 2017), although post-decommissioning monitoring may be conducted to confirm the effectiveness of abandonment practices.

5.1.1 Current Northern Territory requirements

The Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019) requires that decommissioning of a well must be done in a two stage process, The first stage involves verifying the integrity of the well, and setting cement plugs across hydrocarbon bearing zones and aquifers within the well. The surface cement plug is not installed and the wellhead is left in place to allow monitoring of the well. After stage 1, the well must be monitored for duration of 1-6 months, depending on well risk and classification. On successful validation of no well integrity issues, the stage 2 of decommissioning may be completed. In stage 2 the wellhead is removed, surface cement plug is placed in the well and the well pad rehabilitated. The code also has requirements for:

- That cement must be used for plugs along with design and testing criteria for cement.
- Design of cement plugs (see Figure 16).
- The zones along a well that must have cement plugs and the length of those plugs. This includes a requirement to have cement plugs isolating aquifers and hydrocarbon bearing zones from each other and the surface. For example, a cased well section must have good annular cement and a plug extending at least 50 m below the base of, to at least 50 m above the top of, any hydrocarbon bearing zone or aquifer and between permeable zones of different pressure regimes or salinity.
- Verification that cement plugs have been properly installed.
- That there be no annular pressure on any casing annulus before wellhead removal.
- That full details of the decommissioning process are recorded and reported to the regulator.

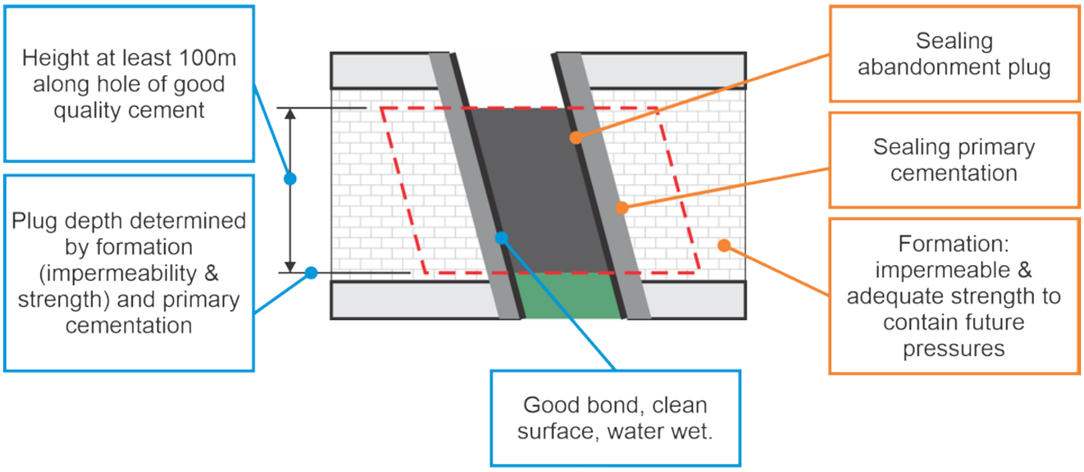

Figure 16: General cement plug requirements for well decommissioning (Northern Territory Government, 2019).

5.2 Well decommissioning technologies

5.2.1 Cement plugs

Cement is the primary material used in plugging petroleum wells for decommissioning. Cement also provides the sheath outside of casing. The cement used in these applications is a highly engineered material.

The two predominate factors to consider in the design of cement plugs are the depth and length of the plugs and the cement placement procedures used to prevent cement slurry contamination (Bois et al., 2018). The other influential factors include but are not limited to geological formation strength to endure the stresses imposed on the wells, wells geometry, and sealing properties of the cement (Dahmani & Hynes, 2017). The design of the cement used in plugs needs to consider temperatures, pressures and the types of fluids the plugs may be exposed to.

The number and the location of the cement plugs are dependent on the number and the location of hydrocarbon regions, flow zones, and over-pressurized zones (Dahmani & Hynes, 2017). Local regulations may also mandate cement plug requirements, as is the case in the Northern Territory (Northern Territory Government, 2019). Similarly, the procedures for placing and testing cement plugs are often regulated. For instance, according to the regulations in Alberta, the well must stay open for inspection for at least five days once the downhole cement plugs have been set. Subsequently, the well is examined for a static-fluid level or other signs of plug leakage (e.g. bubbling in the fluid) before the casing can be cut and capped below grade level (Alberta Energy Regulator, 2018). The Northern Territory Code of Practice also requires cement plugs to be ‘tagged’ with a drill string (physically touched with a minimum load) and for wells to be decommissioned in a staged process allowing monitoring of the well for leaks (Northern Territory Government, 2019).

The integrity of the cement plugs can be assessed when they are placed in the cased section of a well by performing a positive or a negative pressure test. During a positive pressure test, the top of the plug is pressurized to check whether the applied wellhead pressure (WHP) reduces or not during a pre-defined test period. The outcomes of the positive pressure tests demonstrate the effectiveness of the plug against downward fluid flow. However, upward migration of fluids may also happen because of existing pressure from the underneath reservoirs. In negative pressure tests, the pressure above the cement plug is decreased and monitored to check for any upward fluid flow (Bois et al., 2019).

5.2.2 Novel materials

In addition to cement, there are a range of novel materials that are being applied to the remediation of well integrity and in decommissioning. The application of these materials may reduce the well integrity risks posed by a well and decrease the level of monitoring required post abandonment.

Resins

Polymer resins can provide advantages when compared to cementitious materials due to the following characteristics (Beharie et al., 2015):

- High flexibility and less gas permeability
- Their ability to penetrate into the deeper and narrower fractures (due to being solid free)
- Manageable curing time and tuneable viscosity
- Stronger compressive, tensile, shear and bonding strengths
- Superior resistance against contamination of wellbore fluids
- Superior stability and durability while exposing to higher temperature
- Manageable setting time and in some cases manageable viscosity which facilitate pumping and injectivity

In addition, temperature-activated polymer resins can be incorporated in conditions at which the curing time has to commence at a specific curing temperature which prevents the premature setting (Rostoshanshaya, 2019).

Geopolymers

Geopolymers are shown to be very advantageous because of their high compressive strength, high durability encountering corrosive environment, low shrinkage, tolerance to contamination of oil-based muds, high ductility, and their stability at high temperature (Salehi et al., 2017; Khalifeh et al., 2019).

Graphite nanomaterials

Low-cost graphite nanoplatelet (GnP) and carbon nanofiber (CNF) can be employed as nano-scale reinforcement to advance the tensile strength and toughness resistance of the well cement. Incorporating GnP and CNF can reduce the shrinkage volume which results in creation of less microcracks and consequently less well leakage (Peyvandi et al. 2017).

Gels

Preformed particle gels (PPG) are advanced super adsorbent polymers (SAPs) with the capability to absorb liquid more than a hundred times of their weight and not release the absorbed liquid under pressure (Bai et al. 2008). Research studies on the performance of polymer-based gels

(Tongwa et al.,2013), pH-triggered polymer gellant (Tavassoli et al., 2018), and micro-sized crosslinked polymer gels (Abdulfarraj & Imqam 2019a,b) to seal fractures, penetrate into micro fractures, and the strength of the sealed fractures have shown that gels could be suitable candidates to seal the fractures within cement plugs as a potential alternative to setting an additional cement plug on top of the defraded/failed plug.

Alloys

As an alternative to cement, low-melting-point alloys (bismuth-tin alloy (BiSn) containing 58-wt% bismuth (Bi) and 42-wt% tin (Sn)) has been proposed for decommissioning plugs. The incorporation of alloy plugs may result in a cost reduction due to the shorter length required for these plugs to be effective (alloy-plugs are usually shorter than 5m) while cement plug length are required to be at least 30 m long in most jurisdictions (and over 100 m in most scenarios in the NT (Northern Territory Government, 2019)). The melting-point of Bi alloys are in a range of 138℃ to 271℃ which can be applicable in for plugging applications in a wider range of fields. Another potential advantage of alloys is that the volume expands about 3% during solidification and forms a fluid-tight sealant with high compressive, tensile, and bonding strength (H. Zhang et al., 2020, 2021).

Activating shale to create a barrier

Shale has been identified by NORSOK as a good barrier, where they are quoted as stating “Shale, in particular, has all the necessary characteristics which e.g. NORSOK-D010 requires of a good barrier, being largely impermeable, non-shrinking, ductile (not brittle), resistant to different chemicals/substances, wetting to ensure bonding to steel, and providing long-term integrity.” (van Oort et al., 2020).

Creep in shales a time-dependent mechanism which occurs as the minerals deform under stress, and can result the shale creeping to filling any annular gaps. Hence, it is possible that a creeping shale formation could potentially act as a permanent barrier to contaminant flow. Creep can take place in both saturated and dry rocks (unlike consolidation) due to the viscoelastic behaviour of the solid matrix (Cerasi et al., 2017).

Shales that are suitable for the purpose of filling the annular space due to creep have the following characteristics: low strength and high ductility (low Young's Modulus, low cohesion, low friction & dilation angles), high clay content with comparatively high smectite content, low amounts of quartz and carbonate cementation, moderately high porosity, and low compressional wave velocity (Kristiansen et al., 2018). Stimulating and activating the shale in order to expedite the creep rate can happen through temperature and pressure changes imposed to the shales and also utilising some chemicals (Carpenter, 2021).

5.2.3 Alternative plugging approaches

Where well integrity monitoring prior to decommissioning identifies issues with well barrier elements, alternative decommissioning approaches could potentially be applied to re-establish long term integrity as part of the decommissioning process. The majority of these methods involve the removal or by-passing of casing to allow access to the annulus to allow a complete barrier to be installed (Khalifeh & Saasen, 2020). The techniques may include:

- Cutting and pulling casing, where sections of casing are removed from the well,
- Casing milling, where the casing or sections of casing are removed through grinding (or potentially the use of a plasma)
- Perforate, wash and cement, which involves perforating casing in the well, washing out the annular zone and then a cement plug is placed that plugs, through the perforations in the casing, resulting in a cement plug that spans the entire well diameter (formation to formation),
- Melting downhole completions, which involves using high temperatures to melt the downhole completion (casing or tubing) and surrounding formation to create a rock-to-rock barrier.

The latest revision of NORSOK D-010 incorporated some of these approaches, including the perforate, wash and cement well plugging method, section milling and cementing of annulus, use of creeping formation as a barrier element, and premises for accepting material other than cement as barrier material (Standards Norway, 2021).

A common factor in these alternative approaches is to reduce the number of annuli in order to allow the creation of a plug that spans the full well diameter. This reduces or removes some of the possible failure points identified in the risk assessment conducted for this project described in section 3.4. All of these methods are best used to remediate well integrity at the time of decommissioning, rather than as a remedial step once the well has been decommissioned.

5.3 Interventions to remediate decommissioned wells

Interventions to repair leaking decommissioned wells are unusual. The objective of such an intervention would be to re-establish well barriers and stop an unintended flow of fluids from the well identified through monitoring for surface leaks or subsurface fluid contamination. While it is possible to re-enter a well after decommissioning and undertake these interventions, it is not a trivial activity. The process of re-entering a decommissioned well and re-establishing well barrier integrity would need to be conducted in accordance with regulations, including The Code of Practice: Onshore Petroleum Activities in the Northern Territory (Northern Territory Government, 2019). This would involve a well operations management plan and conducting all operations in such a way as to establish and maintain well control throughout the intervention operations. Such an intervention would potentially have a higher level of risk and complexity to the construction of a new petroleum well.

The considerations and challenges involved in re-entering and re-establishing the integrity of well barriers in a decommissioned well can be categorised into three aspects:

1. Identification and characterisation of decommissioned well integrity issues,
2. Consideration of the additional inherent impact of undertaking intervention operations,
3. Assessment of the risks and uncertainties involved in the intervention operations and consideration of these in the design and implementation of the intervention.

5.3.1 Identification of decommissioned well integrity issues

It is difficult to identify that a decommissioned well requires remediation. Well integrity issues in decommissioned wells are only identifiable if there is a leak of fluids (liquids or gasses) at the surface or into (or out of) an interval which is being monitored (monitoring options for decommissioned wells are discussed in section 6).

Leaks from a decommissioned well of a quantity of fluid that can be easily detected through monitoring are rare. Such a leak could only occur if there was a total loss of well control (well integrity failure), a source of fluids and sufficient pressure to cause fluid flow (as discussed in section 3.2). However the magnitude of the driving force and aperture of the leakage pathway are not likely to be apparent from monitoring and as such the failure mechanism is not necessarily obvious .

5.3.2 Pre-intervention impact assessment

In the event that a well is identified to have a leak, an assessment would be needed to determine if the impact of undertaking the intervention is justified against the impact of the leak. More environmental harm may be caused by undertaking the intervention than from the leak and that other 'offset' actions may provide a greater environmental benefit. The impacts of a leak could also be mitigated. For example, methane emissions from landfills can be reduced by enhancing biological degradation in the cover material (Pehme et al., 2020)

5.3.3 Intervention design and implementation

In order to re-enter a decommissioned well, a well operations management plan must be in place. There is a high degree of uncertainty when re-entering a decommissioned well as no two leaking decommissioned wells are identical and often there is a lack of data about how the well was initially constructed and operated (Ward, 2017). Operators will need to make pragmatic assumptions when completing this risk assessment. Suitable controls will need to be put in place to ensure well control is maintained throughout the intervention including the reinstatement of the wellhead and blowout prevention systems. The difficulties and risks involved in undertaking well re-entry and remediation operations are highlighted in (Skinner, 2019 p314) where an example is given of a decommissioned well intervention where the risks and subsurface conditions were not adequately understood or managed leading to loss of well control (blowout).

The likelihood of success of an intervention in restoring the well barriers and stopping the leak are dependent on the nature of the well barrier failure. For example a failure of the cement plugs (section 3.4.3) could be remediated by removal and re-setting of the plugs. Casing failure (section 3.4.2) could also be relatively easy to identify and undertake remediation operations. However a failure of the cement sheath (section 3.4.1) or a micro annuli (Section 3.4.5) over a significant portion of the well would be more difficult to access and remediate as the failure would be behind the casing and more difficult to access and address the leakage pathways. Intensive remediation activities such as perforate, wash and cement or section milling are likely to be required.

6 Well integrity monitoring for decommissioned wells

There are two objectives of well integrity monitoring (see section 4.1). The first is to monitor the well barrier elements to confirm that they are meeting their performance criteria and are not degrading. The second objective is to monitor for the consequences of breaches of well integrity that have led to a release of fluids from the well.

As shown in Figure 17, the opportunities to undertake actions to change the integrity performance of a well and to monitor for well integrity failures evolve over the well 'life-cycle'. The majority of the factors which determine if a well will have future integrity issues (potential future leaks) exist during the design and construction phases. It is here that the operators make decisions (in line with the regulations) on what type and how a well will be constructed. The design, construction and successful validation of each well integrity barrier is a very strong indicator of the likely future (post-decommissioning) well integrity performance.

The best opportunity to monitor for well integrity performance is during the well's operational life. The information on the integrity status of each well barrier element, which is gathered through this operational phase, must be included in designing the specific decommissioning strategy for the well. It is critical that the well decommissioning strategy remediates any well integrity failures prior to or during the decommissioning process.

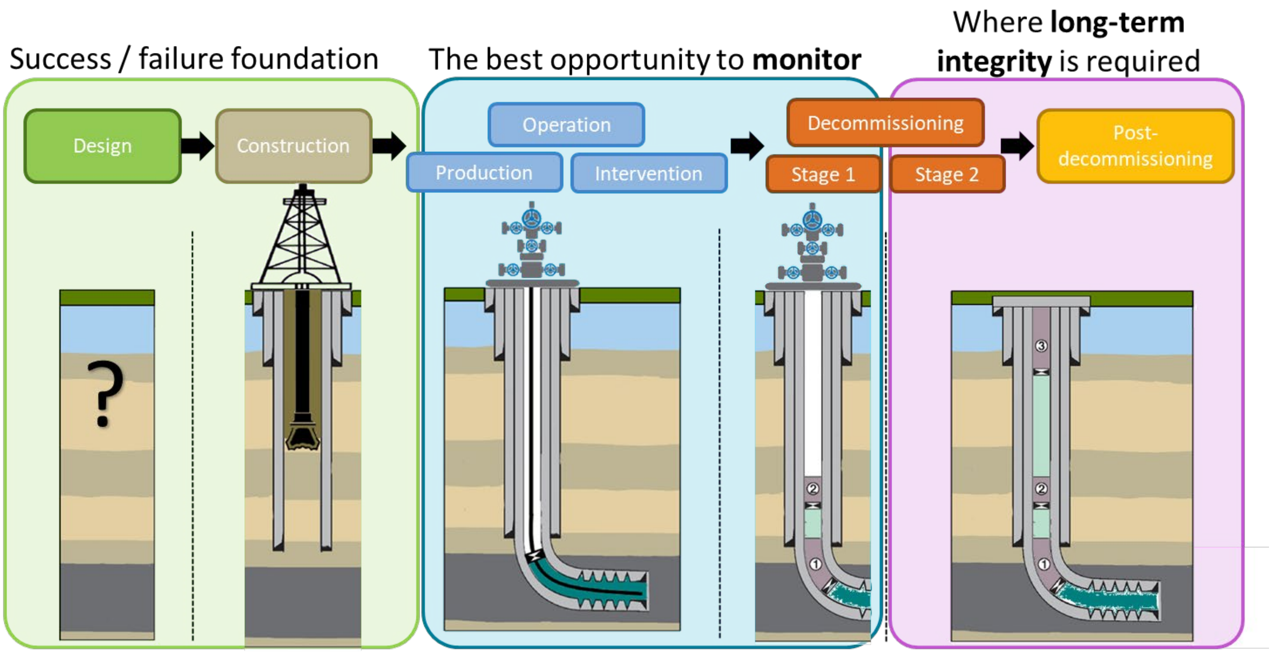

Figure 17 - The impacts and opportunities to monitor the well integrity in each of the well life-cycle phases

The process of decommissioning onshore wells in the Northern Territory is a two-stage process. Stage 1 begins with a review of well integrity. This may involve collecting data (direct subsurface monitoring) and conducting any remediation required to restore the integrity of well barriers. After integrity has been confirmed, the installation of cement plugs can commence. Between

Stage 1 and Stage 2 of decommissioning, the wellhead is left in place and monitoring occurs to make sure there are no leaks along the annulus or past the cement plugs.

Stage 2 of decommissioning in the Northern Territory is to install a surface plug and remove the wellhead. The well is then capped, and surface remediation works undertaken. Once the wellhead is removed in the final stage (Stage 2) of decommissioning the ability to monitor the subsurface is significantly reduced. Monitoring for the first objective (condition of well barrier elements) is not possible after this stage with current monitoring technologies. Monitoring for the second objective (evidence of a leak) through monitoring of atmosphere, groundwater and soil is can be conducted but the link back to the nature and location of any leak from a well integrity failure is very difficult to make.

Therefore, it is critically important that the well is in the best possible condition before stage 2 decommissioning occurs. As shown in Figure 18 the available monitoring options gets significantly limited after stage 2. The time immediately prior to decommissioning stage 1 in the Northern Territory also provides the best opportunity for operators to demonstrate the integrity of the well and undertake remediation works as required 5).

The time in between the two decommissioning stages in the Northern Territory provides the best opportunity to monitor the status of the decommissioned wells. The capturing and public reporting of the integrity status of a decommissioned well would provide the most valuable information to the public and regulator as to the potential risks of well integrity failure.

Taking these options and opportunities into account, the schematic in Figure 18 below shows how the possible monitoring parameters evolve depending on the phase of the well 'life-cycle' however any monitoring approaches should be based on performed risk assessment, the resultant environmental effects, and the associated costs.

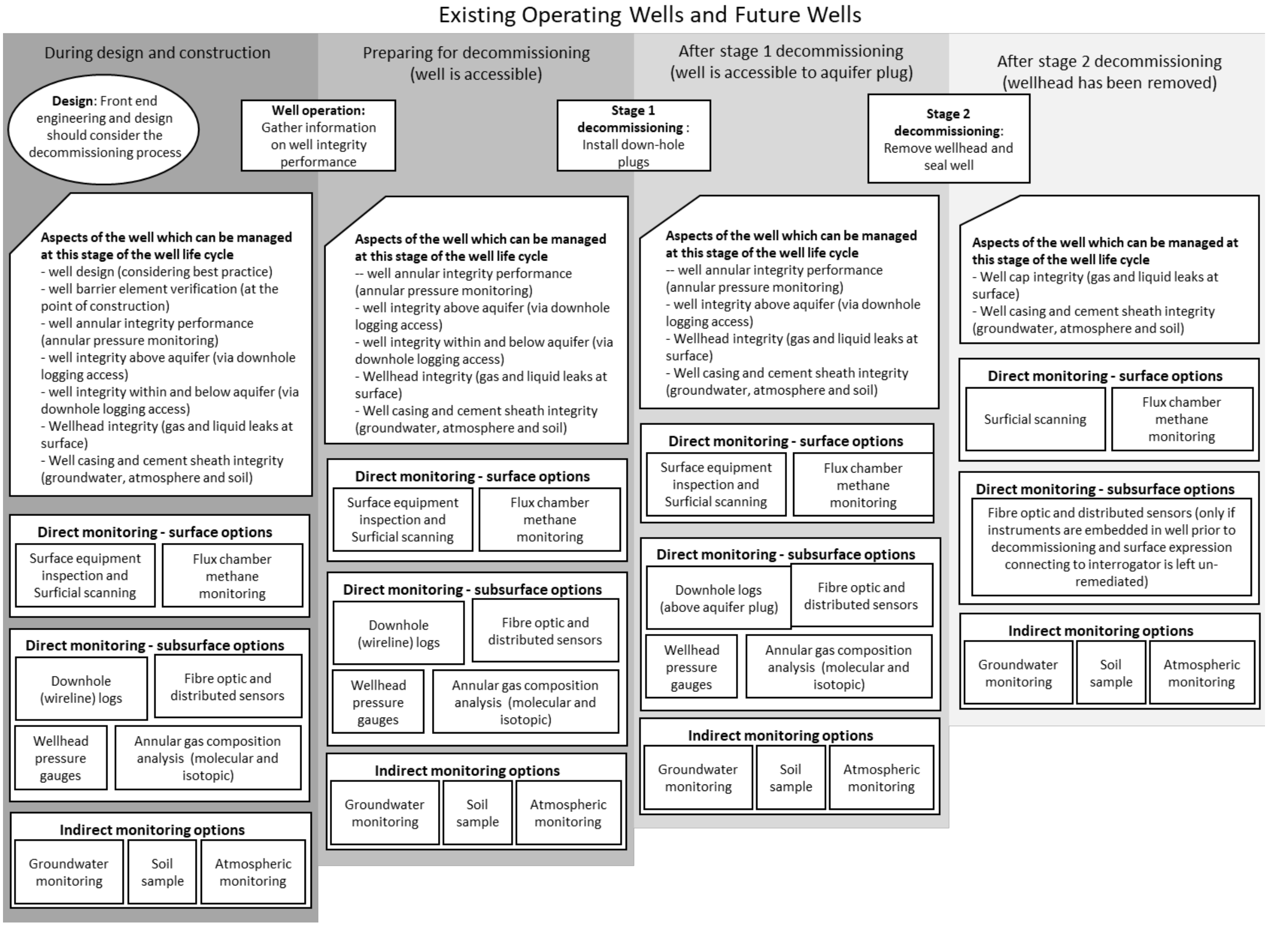

Figure 18 - Monitoring options available throughout the life cycle of the well

6.1 Well integrity monitoring for currently operating and future wells

The accessibility of operating and future wells allows a full range of monitoring options to be considered, including direct monitoring at the surface, direct monitoring in the subsurface in addition to indirect monitoring approaches. Examples of the application of different monitoring operations have been provided in section 7, which provides insights into their merits and limitations of each approach.

6.1.1 Monitoring framework for currently operating and future wells

Figure 18 demonstrates the available monitoring approaches for producing and future wells in a staged plan. The framework includes well integrity investigation and preparation of wells before plugging and decommissioning. This component verifies the integrity of barrier elements as the first step where there are more monitoring and intervention options available. As decommissioning progresses toward the last step, which is wellhead removal, the options become increasingly limited.

Table 2 sets out a framework of monitoring options for currently operating and future wells that are about to be decommissioned. This framework considers industry best practice and regulatory requirements to manage well integrity throughout the well lifecycle. The framework shows that there are many more monitoring options prior to plugging of the well. Once plugs are set, monitoring for well barrier performance is no longer possible, and monitoring is restricted to looking for evidence of a well integrity leak.

Table 2 - Framework of monitoring approaches for currently operating and future wells. Heavy outlines where monitoring for well barrier performance can be done.

	During design and Construction	Preparing for decommissioning	After reservoir plug installation	After all plugs installed	After wellhead removal
Cement sheath failure	Best: d, c Else: f, b, a	Best: d, c Else: f, e, b, a	Best: e, c Else: f, b, a	Best: c Else: f, b, a	Best: a Else: b
Casing failure	Best: d, c, f Else: f, b, a	Best: d, c Else: f, b, a	Best: e, c Else: f, b, a	Best: a Else: b	Best: a Else: b
Plug failure	N/A	N/A	Best: c Else: f, b, a	Best: c Else: f, b, a	Best: b Else: a
Surface equipment failure	Best: c Else: N/A	Best: c Else: N/A	Best: c Else: N/A	Best: c Else: N/A	N/A
Cement bond failure (micro-annuli)	Best: d, c Else: f, b ,a	Best: d, c Else: f, b ,a	Best: e, c Else: f, b ,a	Best: c Else: f, b, a	Best: a Else: b
Any failure leading to gas emissions	N/A	N/A	Best: c Else: e, b, a, f	Best: a Else: b	Best: a Else: b
Any failure leading to liquid emissions	N/A	N/A	Best: a Else: f	Best: a Else: N/A	Best: a Else: N/A

a. Groundwater monitoring, atmospheric monitoring [Indirect monitoring]
b. Surficial scanning, Static chamber flux measurements, Soil monitoring [Specific to each well]
c. Wellhead pressure gauges, surface equipment inspection [Standard equipment]
d. Downhole logs
e. Downhole logs that can only be run to the depth of the top of the shallowest plug installed
f. Real-time compaction imager, DTS, DTSS, DAS [Advanced fibre-optic measurements]

Effectiveness of monitoring (likelihood that monitoring could detect a well integrity failure)	Almost certain	Very high	High	Moderate	Low	Almost impossible

Direct subsurface monitoring after the first stage of well decommissioning will allow the integrity of these wells to be confirmed. Monitoring of annular pressures at the well head can be conducted and data can be transmitted in real time. More advanced techniques, including those that use distributed fibre optic sensing may also provide information on fluid movement along a well and could be accessed while a wellhead was still on the well. However, there is little data available on the performance of these systems and the significance of data generated.

Direct monitoring at the surface (immediately above a well that has been fully decommissioned) through methane gas detection, along with indirect monitoring for methane at the well pad scale, is likely to provide the most effective monitoring for fully decommissioned wells. The buoyancy and mobility of methane gas means it is the most likely fluid to move along a well with integrity issues (as long as there is a methane source). The availability of reliable, robust and sensitive methane detectors that can be used in the field should allow leaks that reach the surface to be detected. Other methods may be deployed to investigate the source of methane (isotopic measurements, monitoring for longer chain hydrocarbons).

6.2 Well integrity monitoring for relinquished wells

Part of recommendation 5.2 of Scientific Inquiry Into Hydraulic Fracturing in the Northern Territory (Pepper et al., 2018) was that the NT government "implements a program for the ongoing monitoring of all orphan wells." In recommendation 14.14, the inquiry refers to a "levy for the long-term monitoring, management and remediation of abandoned onshore shale gas wells in the NT.

In section 5.2.2 of the inquiry's final report (Pepper et al., 2018), the inquiry has a definition of "orphan" as part of a description of the final stage of shale gas exploration and resource development as follows:

> *"**stage 7**: abandonment (also referred to as' relinquishment', if a planned process) – as far as the operator is concerned, this occurs when a period of post-decommissioning monitoring (groundwater quality and fugitive methane) has shown no unacceptable leakage issues, and the state assumes responsibility for long-term stewardship of the well. At this time, the well is technically defined as an orphan, under the care of the state."*

This use of the term orphan is not consistent with the use in other jurisdictions. The Orphaned Well Association (OWA, https://www.orphanwell.ca/) in Alberta Canada describes the term orphan as follows

> *"In the upstream oil and gas industry, an orphan is a well, pipeline, facility or associated site that does not have a legally responsible and/or financially viable party to deal with its decommissioning and reclamation responsibilities."*

The (OWA) definition of "orphan" is more widely accepted, with the key aspect being that the infrastructure has not been properly decommissioned and that the responsible party is not able to meet their obligations for decommissioning. For petroleum wells, this is a significant issue in North America where there are hundreds of thousands of wells that are considered orphaned (Orphan Well Association, 2021). The regulatory regime and relatively small size of the petroleum industry in Australia (with less than 30,000 wells onshore) means that wells that are orphaned are not commonplace. Petroleum operators have generally complied with the obligations placed on them at the time they relinquish their petroleum titles. The accepted practice is that once the operators have met these obligations to the satisfaction of the relevant regulator, they no longer have responsibility for the wells on the petroleum titles areas relinquished.

Decommissioned (or abandoned) wells may present a level of residual risk. Queensland Government has recently enacted reforms to its environmental regulation to address residual risk through the Mineral and Energy Resources (Financial Provisioning) Act 2018 (Queensland). Residuals are the risks that remain after a facility (such as a well) has been decommissioned, rehabilitated and relinquished. The operator is no longer responsible for the site of the facility, or any ongoing monitoring or maintenance. Residual risks include the risk of the decommissioning or rehabilitation failing. Residual risks may be reduced through ongoing monitoring to ensure the decommissioning and rehabilitation continues to be effective. The Queensland Government has established requirements for Environmental Authority holders for resource activities to determine their residual risk and make a payment as part of the surrender process. These payments are used for a fund to cover future costs of managing the residual risk from resource activities. The New Zealand government is also establishing legislation around residual liability for petroleum wells and infrastructure following decommissioning.

Long term monitoring options for decommissioned wells remain the same whether the well is referred to as “orphan” or “relinquished.” The focus of this section is on monitoring for wells that have already been decommissioned. These include wells recently decommissioned as well as older wells for which there may be varying amounts of information available.

6.2.1 Relinquished wells in the Northern Territory

In the Northern Territory, as at the end of January 2022, there were 248 confirmed petroleum wells. This count is based on the definition of a well as a unique surface location. Some of these wells have one or more sidetracks, which are additional wellbores drilled away from the original wellbore to bypass an obstruction in the well, to investigate nearby geological features or other engineering purposes. There are around 30 sidetracks in the Northern Territory.

Of the 248 petroleum wells:

- 112 wells have been identified as under the custody of the Northern Territory. These are the wells that best fit the use of the term “orphan” in recommendation 5.2 of the Scientific Inquiry Into Hydraulic Fracturing in the Northern Territory (Pepper et al., 2018).
- 136 wells are under the custody of various operators:
    - 38 are decommissioned (plugged and abandoned)
    - 98 are either operating or suspended.

The oldest of the 112 relinquished or orphan wells, Bathurst Island 1, was drilled in 1960. A further 31 wells were drilled in the 1960’s, predominantly in the Amadeus Basin west of Alice Springs. Around 20 wells were drilled through the early 1980’s with the majority in the Amadeus Basin. A further 50 or so wells drilled in the late 1980’s to early 1990’s with most activity in the MacArthur Basin (including the Beetaloo Sub-basin) and Georgina Basin (south east Northern Territory). The youngest relinquished wells were drilled in the 2010’s in the Georgina and MacArthur Basins. Figure 19 presents a summary of the age and locations of relinquished petroleum wells in the Northern Territory.

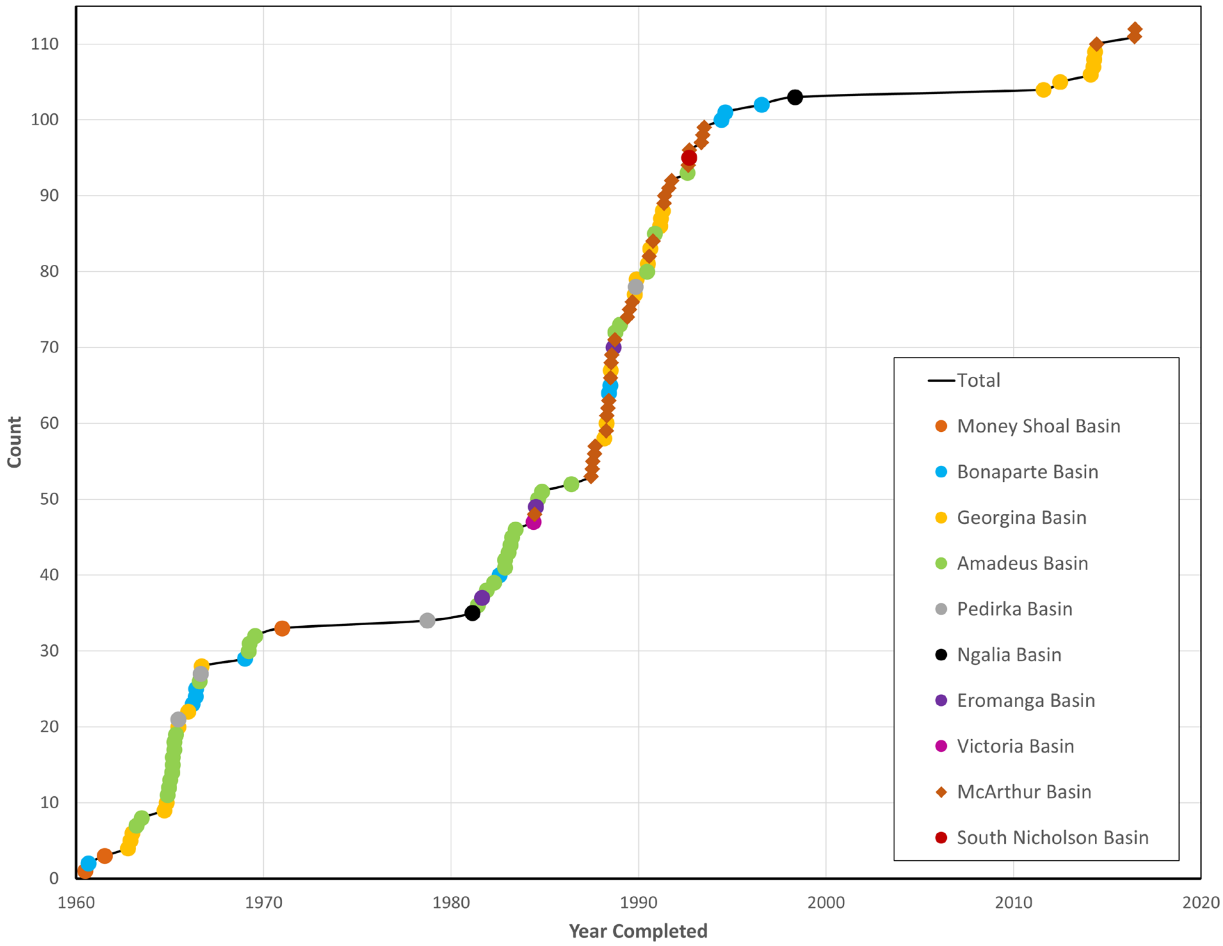

Figure 19: Age and location of relinquished (or "orphan") wells in the Northern Territory. Data sourced from STRIKE (Northern Teritory Government, n.d.).

All wells in the Northern Territory will eventually by decommissioned and the petroleum titles surrendered. Once this occurs, any future monitoring, management and remediation would likely be the responsibility of the Northern Territory Government, in line with recommendation 14.14 of the Scientific Inquiry Into Hydraulic Fracturing in the Northern Territory (Pepper et al., 2018).

6.2.2 Locating relinquished wells

Before a well can be monitored, its surface location must be found. While all of the Northern Territory's relinquished wells have locations recorded, older decommissioned wells may be difficult to locate due to errors in historical surveying methods and removal of any form of surface expression. Most decommissioned wells in the Northern Territory's locations are marked by a surface marker (Figure 20), however this is not always the case. When a surface marker is present, the exact location of a well may not be certain as there may be no surface expression if the well has been cut off below the ground surface, as required by the regulations.

The surface location of well without a surface marker can be determined by a range of methods (Aller, 1984; Jordan & Hare, 2002). Local knowledge may also be valuable in identifying the locations of wells. Landholders, current holders of any petroleum title, park rangers and members of other government agencies (depending on current land use and land administration arrangements) may have on-ground information about the location of wells. Aerial or satellite imagery and geophysical methods may also be used to identify well locations.

Figure 20: An example of a surface marker for a decommissioned well in the Northern Territory.

Aerial photography and satellite imagery

At the kilometre scale, the disturbance caused by the preparation of a well pad and access tracks may allow a well's general location to be found from aerial photography or satellite imagery. In some instances, these disturbances may still be observable in recently collected high resolution aerial photography and satellite images. Publicly available high resolution imagery is available through a number of platforms, including Esri's World Imagery (Esri, n.d.) and Bing™ Maps Imagery (available through the NationalMap platform Australian Government, n.d.). A number of commercial satellites, such as WorldView-3 and Pleiades, are able to provide very high-resolution imagery (<0.5m).

This imagery may be useful for providing current day observations. However, rehabilitation of well pads and revegetation through time may make them difficult to detect. Historical aerial and satellite imagery may be useful in this case.

Aerial photo coverage of the Northern Territory is available from the Northern Territory's Aerial Photography Index (Northern Territory Government, 2000) and the Historical Aerial Photography collection developed by Geoscience Australia (Geoscience Australia, n.d.-b). The coverage of aerial photography is not spatially or temporally complete, and the image needs to have been collected at a point in time when the signature of drilling activities is still visible. In arid environments this signature may not persist as there may be little to distinguish a well pad from the sparsely vegetated ground around it, although revegetation of well pads may be slower. Aerial photography may be more useful in areas that have required mature vegetation to be cleared, or where images have been collected soon after drilling has been completed. The spatial resolution of aerial photography is typically at the metre scale allowing features the size of well pads and access tracks to be identified. Geolocation of aerial photography depends on the accuracy of information captured when the images were taken. Older images collected prior to modern navigation aids, such as the Global Positioning System, may have less accurate position data than those collected in more recent surveys. However, relative locations of features in an aerial photograph may allow their location to be determined to metre scale precision.

Legacy satellite imagery provides another dataset that may assist in locating well locations. Landsat satellite imagery has been collected since 1972 and provides an unparalleled record of historical land cover (Wulder et al., 2012, 2018). The use of legacy Landsat data for locating well locations will be limited by its spatial and spectral resolution. The Multi Spectral Scanner (MSS) used on Landsat 1-5 had a spatial resolution of sixty metres, which is similar to the size of a well pad. The Thematic Mapper TM used on Landsat 4 and 5, the Enhanced Thematic Mapper Plus (ETM+) used on Landsat 7 have a spatial resolution of thirty metres. Around 30 of the NT's relinquished wells were drilled prior to 1972 and won't have Landsat imagery available for the period of drilling activity. The remaining 80 or so wells were drilled from the early 1980's and are likely to have Landsat 4 and 5 coverage. Figure 21 provides an example of a well pad visible in Landsat TM data when compared to pre-drilling. These images highlight the relatively poor spatial resolution of this imagery and the challenge in using it to locate wells. Landsat 1-4 imagery is available from the United States Geological Service's EarthExplorer platform (USGS, n.d.). Landsat 5 and later images are available from Digital Earth Australia (Geoscience Australia, n.d.-a).

In addition to optical or reflectance images, satellite sensors include multispectral, hyperspectral thermal and radar sensors. Kuenzer et al (2014) provide a detailed review of earth observing satellites and their sensor characteristics as at 2014. The data collected by these sensors can detect subtle changes in vegetation and soil composition, and have been successfully applied to archaeological studies (Hadjimitsis et al., 2013), which have similar requirements to detecting well pads. The application of remote sensing technologies will depend on the characteristics of the site and would need to be considered on a case-by-case basis. Levick et al (Levick et al., 2021) provide a recent example of how remote sensing can be applied to a specific task (mapping gamba grass).

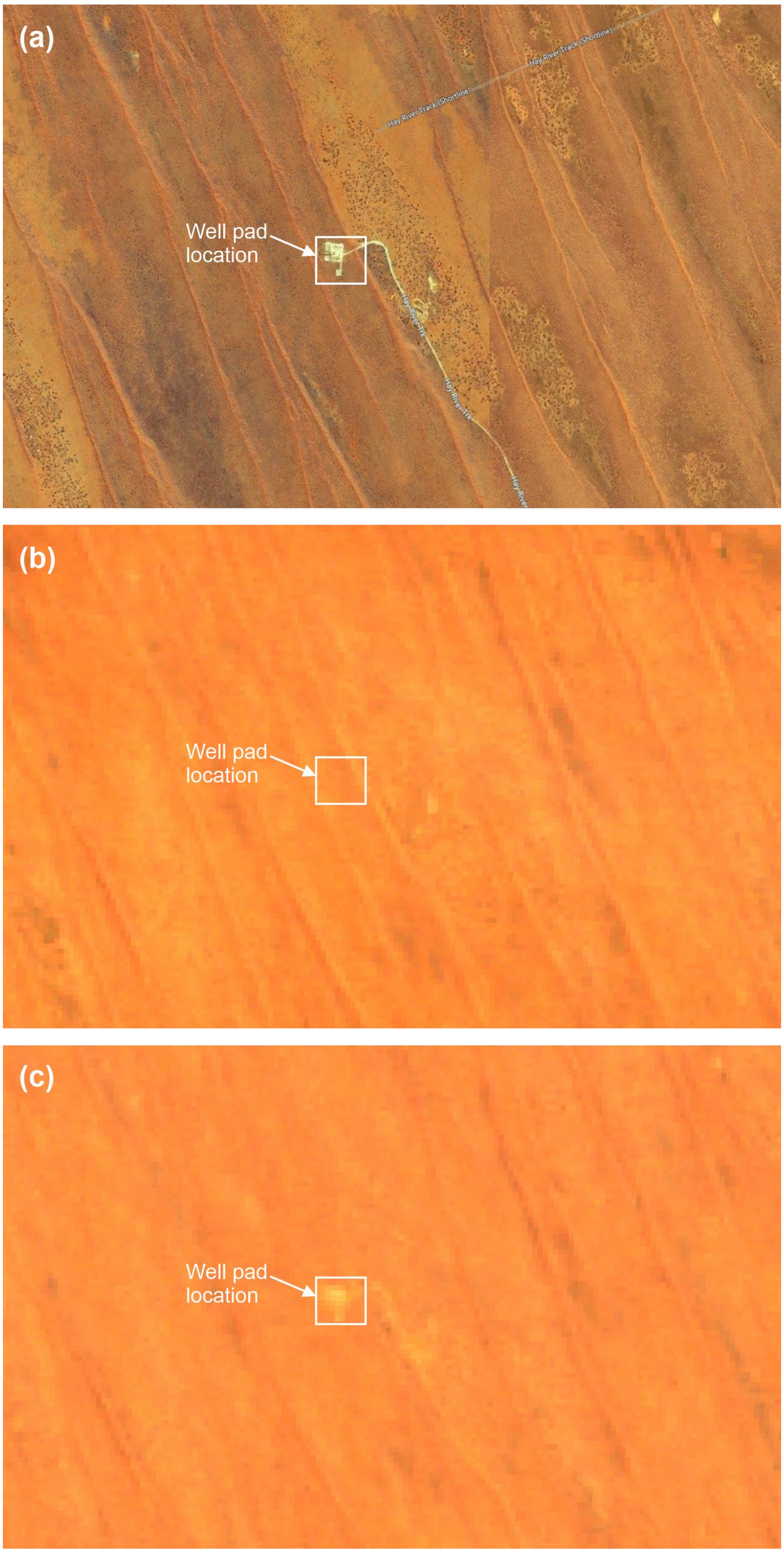

Figure 21: Aerial imagery (a) and Landsat Surface Reflectance imagery (b and c) of the Poeppels Corner 1 well. This well was drilled in September 1989. Image (b) was collected on 28 April 1988, prior to drilling or the construction of the well pad. Image (c) was collected on 7 September 1989 while the well was being drilled.

These images were created using https://maps.dea.ga.gov.au on Wed Mar 16 2022 18:13:28
An interactive version of this map can be found here:
https://maps.dea.ga.gov.au/#share=s-lEUlvJcDGBYgRfurEug4Inqa5me

Geophysical methods

The location of the well may be determined using a number of geophysical methods. It is highly likely that all wells decommissioned in the Northern Territory will have steel casing in place, which provides a target for geophysical methods. Jordan & Hare (2002) provide a very good summary of these methods, including their underlying geophysical basis. Near surface geophysics are also employed for civil engineering and archaeological applications that have similar requirements to the location of wells (Gelbke et al., 2005). These techniques may be useful in confirming the location of a well once the location of a well site has been determined at the kilometre scale. The main techniques that are likely to be of value in the Northern Territory context are summarised below.

Magnetics

Magnetic surveys detect anomalies in the earth's magnetic field that result from contrasts in the magnetic susceptibility of materials in the earth. The magnetic susceptibility of steel is three to five magnitudes higher than that of the sedimentary rocks that petroleum wells are drilled in. The size of the magnetic anomaly due to steel well casing will depend on the size of the casing and the depth to which it is buried. As a result, magnetic surveys are very powerful in terms of their capability to detect wells with no above ground evidence, including wells that have been partly cut off or have had the upper casing removed, reclaimed sites, and even those sites obscured by mine spoils at depths of up to 30 m.

Magnetic surveys can be conducted using airborne or ground based sensors platforms. Airborne magnetic surveys can cover a large area quickly and have been successfully deployed for finding abandoned petroleum wells in a number of studies (Frischknecht et al., 1985; Hammack et al., 2016; Kaminski et al., 2018; Saint-Vincent et al., 2020; Sams et al., 2017; Veloski et al., 2008). A common feature of these surveys is the need to collect data at low flight altitudes (25 m to 50 m above ground level) and with close line spacing (10 m to 30 m). These requirements are due to the small size of the anomaly associated with abandoned wells and to provide sufficient spatial resolution. The low altitude typically requires the survey to be undertaken using helicopter based aeromagnetic surveys.

Ground based magnetic surveys have also been used to find abandoned petroleum and water wells (Hammack et al., 2016; Patton et al., 2018; Saribudak et al., 2017). These surveys are usually conducted by an operator on foot using a magnetometer with an integrated GPS to record locations. The surveys on a grid with a line spacing on the order of 20 m is likely to be sufficient (Patton et al., 2018). A survey of an area the size of a well pad (around one hectare) could be completed in under an hour. A finer grid could be used once the general location of an anomaly has been determined.

Recently, magnetic surveys using unmanned autonomous vehicles (UAV) have been used in mineral exploration (Parshin et al., 2018; Walter et al., 2020) and for the location of abandoned wells (de Smet et al., 2021; Nikulin & De Smet, 2019; Saint-Vincent et al., 2021). UAV's can be flown at lower altitudes than manned aircraft providing the resolution of ground surveys while still allowing large areas (square kilometre scale) to be surveyed rapidly. UAVs cost less to operate than helicopters. UAV's need ground support immediately adjacent to the survey area while helicopters can operate from further away (although long transits may not be possible due to the configuration of the sensor equipment).

For the Northern Territory, only a small number of relinquished/orphan wells are likely to require location using geophysical means. UAV based magnetic surveys may be most suitable when the level of uncertainty in a well's location is at the kilometre scale, while ground based magnetics surveys may be more appropriate at the hundreds of metre scale. Either technique is likely to require an operator with expertise in designing and conducting magnetic surveys. The location accuracy of these methods is in the order of a few metres.

Once a well has been located to the metre scale, or where a well's location is identified by a marker, handheld magnetic locators can be used to locate the well location. These are simple systems that work on a similar principle to magnetic surveys, but do not require specialist skills to operate. Examples of these instruments include the Maggie magnetic locator manufactured by Schonstedt Instrument Co, the Maghorn magnetic locator manufactured by Pipehorn and the ML-1 manufactured by Subsurface Instruments.

Other geophysical methods

While magnetic surveys are likely to be sufficient to confirm the location of any wells with no surface features, the method relies on the presence of steel casing and the absence of other magnetic anomalies that may cause interference. There are several other geophysical methods that could be used if necessary.

Light Detection and Ranging (LiDAR) computes the distance between a probe and the target employing lasers. The time delay in detecting the light reflected from the target is determined to map surface or ground features, allowing the visualization of ground under forests or modifications to surface features. This method has been used to determine well locations by identifying surface features (changes to topography) where other techniques have failed (Saint-Vincent et al., 2021). The flat nature of the Northern Territory's topography is likely to reduce the effectiveness of this method.

Electrical and electromagnetic methods are based on the way the earth responds to an applied or natural electromagnetic fields (Jordan & Hare, 2002). These methods are generally more complicated than magnetic surveys, and their application may only be warranted when the location of a well can't be determined using magnetic methods. Transient electromagnetic (TEM) and Frequency-domain electromagnetic (FEM) can be used to detect non-magnetic metals, such as stainless steel, and possibly heavily corroded casing. FEM is the basis for inexpensive, low-powered metal detectors, these instruments do not have the depth penetration capabilities needed to detect well casing. Electrical and electromagnetic methods may have an application in detecting brine plumes or fluid leakage from wells due to changes in the electrical conductivity of an impacted groundwater body.

Ground-penetrating radar (GPR) is commonly used for detecting subsurface infrastructure in engineering and geotechnical applications (Gelbke et al., 2005; Jordan & Hare, 2002). This method may have application for small scale, detailed surveys or in areas where there are other man made features (Hammack & Veloski, 2016; Veloski et al., 2007). GPR could be used to determine the size of the surface plug, the depth to the top of the surface plug and whether remnants of a cellar (an excavation around the top of the well for well head equipment, usually lined with cement).

6.2.3 Relinquished/Orphan well risks

Assessing the long term well integrity risk posed by wells that have already been decommissioned and relinquished assists in informing the ongoing monitoring requirements for these wells. Wells with little to no risk do not warrant the same level of monitoring as wells with a higher risk. The conceptual model for decommissioned well integrity (section 3.2) still applies, as do the key failure modes identified in the causal network (section 3.4). The availability and quality of information about a well and its integrity would need to be considered as it is unlikely that additional data could be acquired.

Table 3 shows the key considerations when evaluating the well integrity of relinquished wells. Many of the relinquished wells in the Northern Territory were drilled for exploration purposes and were abandoned as they did not encounter a petroleum resource. These wells may not contain any significant volume of hydrocarbons. They may have encountered saline groundwater.

Table 3: Well integrity risk considerations for relinquished wells

Parameter	Criteria	Potential sources of uncertainty
Is there a source of fluid?	Did the well intercept a fluid source or sources that may cause environmental harm? This could include: • Hydrocarbons (gas or liquids) • Saline groundatwer. What is the size of the fluid source? • Thickness – exposure to well. • Lateral extent. What is the mobility of the fluid? • Permeability of the formation that the fluid is in. • Whether any stimulation activities were conducted (hydraulic fracturing, acidizing, pressure support).	Was the necessary data collected to characterise all fluid bearing formations? What is the reliability of this information? Are the characteristics based on flow testing or inference from other data?
Is there a driving force?	Wha are the driving forces for fluid movement, if any? These could include: • Overpressures. • Gas buoyancy. What is the prognosis for the driving forces to change over time?	Reliability of characterisation and testing activities?
Is there a pathway? (Well integrity)	Are the fluid source(s) separated from receptors by adequate, verified barriers? • Characteristics and depths of installed well barriers. • Characteristics of individual well barrier elements. • Design, acceptance and verification criteria for the well barrier elements. • Regulatory requirements in place at the time of abandonment.	Are there complete records for well integrity? Key aspects of the well are: • Level of detail available on well integrity verification prior to decommissioning. • Level of detail on well barrier elements and their design performance. • Level of detail on verification of well barrier elements. • Details of well operations throughout the well's lifecycle that impact on well integrity.

An assessment of the risks posed by a relinquished well also need to consider the receptor that may be impacted by a release of fluids. Where hydrocarbon gasses are the source fluid, the main receptor is the atmosphere and the potential impact is an increase in greenhouse gasses. The data on decommissioned well leakage rates shown in Figure 6 suggest that the impacts on greenhouse gas concentrations due to an individual well with compromised integrity will be negligible. For a decommissioned well to release a significant level of hydrocarbon gas, the barriers between the source and atmosphere would need to have completely failed or be absent. In this case there may be a risk posed by the gas in the immediate vicinity of the well, particularly if there is potential for the gas to accumulate as the gas may sustain a flame if ignited. A leak of this nature would be easily detected with handheld methane monitoring equipment.

If the source fluid is saline groundwater or liquid hydrocarbons, then environmental receptors including groundwater, surfacewater and soil along with ecosystems dependent on them may be impacted. Release of fluids from a well may lead to contamination, which if in high enough concentrations, may cause harm. The sensitivity or importance (environmental, cultural and heritage) of surface receptors are a factor in determining the level of risk for a decommissioned well.

An assessment of the well integrity risks for the relinquished wells in the NT is beyond the scope of this report. However, in assessing ongoing monitoring options an assessment based on the criteria outlined in Table 3, along with a consideration of the potential receptors, would be a valuable input into the design of an ongoing monitoring program.

6.2.4 Monitoring relinquished/orphan decommissioned wells.

In most instances relinquished well in the NT have been abandoned (decommissioned), including the installation of downhole cement plugs, removal of the wellhead and any other surface expression of the well. In most cases the surrounding well pad will have been rehabilitated.

At this stage the only monitoring options left are direct monitoring at the surface (at the well location) for evidence of fluid reaching the surface (is there fluid bubbling up from the ground, is there a gas leak at the surface) and indirect monitoring of groundwater, atmospheric composition, and soil (Figure 22). Monitoring of the subsurface is not possible for these wells.

The Pepper recommendation for a monitoring program by the regulator for wells once relinquished did not state a timeframe (Pepper et al., 2018). A monitoring program for relinquished wells should take into account the risk posed by the well. Periodic monitoring at the well location for methane, or groundwater monitoring where there is evidence that liquid hydrocarbons or saline groundwater may move along the well, at intervals commensurate with the risk are the only viable options. Monitoring through the current generation of airborne or satellite based sensors is not sensitive enough to detect leaks. While there are sensors that are sensitive enough to deploy as unmanned monitoring equipment in the field, their deployment for decades or longer was never contemplated by their manufacturers. Long term (decades to centuries) monitoring is currently limited to periodic site visits using the best available sensing technology available at the time.

For wells that have already been relinquished (or orphan wells), a campaign to conduct desktop studies to ascertain the well integrity risks posed by the wells combined with initial site surveys to check for methane gas anomalies will allow the design of an ongoing monitoring program.

All wells drilled in the Northern Territory will eventually be relinquished. The need for monitoring of these wells can be reduced through monitoring to confirm their well integrity at the time of decommissioning to reduce their long term post decommissioning risk to a level as low as reasonably practical. Ongoing monitoring can be designed by considering the residual risk remaining at the time of decommissioning.

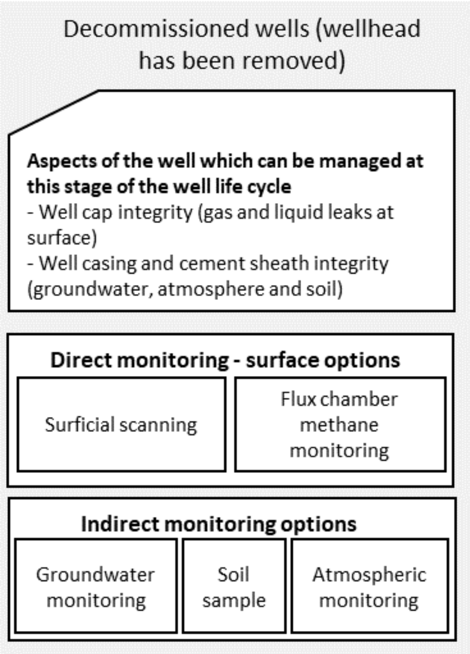

Figure 22 - Monitoring options available for decommissioned wells

7 Example monitoring approaches against well integrity scenarios

The efficiency and applicability of monitoring options and remediation procedures are dependent on the well status (life-cycle phase) and well barrier integrity issues. Table 4 describes different scenarios in which wells are at different phases of the life-cycle with different well barrier component integrity issues. A qualitative review of the effectiveness of monitoring and remediation strategies and the associated likelihood of continuing well integrity issue for each scenario.

The examples presented here are illustrative and by no means meant to be prescriptive.

Table 4 : Monitoring and remediation steps based on well life-cycle phase and well barrier integrity issues

Description	Life-cycle phase	Monitoring and remediation steps
Scenario 1 : Casing corrosion within reservoir and aquitard	Preparing for decommissioning	**Monitoring that would detect the well integrity issue**: Downhole logging tools, pressure monitoring **Remediation**: Casing patches/liners or straddle packers if required **Potential for enduring well integrity issue**: Possible. Unlikely to reach atmosphere or groundwater without other well integrity failures.
Scenario 2 : Cement bond failure from reservoir to aquifer	Preparing for decommissioning	**Monitoring that would detect the well integrity issue**: Downhole logging tools, pressure monitoring **Remediation**: Cement squeeze **Potential for enduring well integrity issue**: Plausible. Fluid movement along this pathway would require driving force. Flow rate limited by small size of pathway.
Scenario 3 : Cement sheath failure within reservoir	Preparing for decommissioning	**Monitoring that would detect the well integrity issue**: Groundwater monitoring, well logs (surveys), pressure monitoring **Remediation**: Cement squeeze **Potential for enduring well integrity issue**: Not anticipated

Scenario 4 : Production tubing failure	Preparing for decommissioning	**Monitoring that would detect the well integrity issue**: Wellhead pressure gauges (inner annulus) with integrity tests of well barrier elements to pinpoint the issue **Remediation**: Removal of production tubing **Potential for enduring well integrity issue**: No enduring well integrity issue
Scenario 5 : Reservoir cement plug failure after decommissioning stage 1	After stage 1 decommissioning	**Monitoring that would detect the well integrity issue:** Wellhead pressure gauges (inner annulus) with positive and negative pressure testing on plug to pinpoint the issue **Remediation**: Removal and reinstallation or remediation of plug then re-test **Potential for enduring well integrity issue**: No enduring well integrity issue
Scenario 6 : Leakage detected after decommissioning	After stage 2 decommissioning (or rekinquished/ orphan well).	**Monitoring that would detect the well integrity issue**: Visual inspection, mthane detection, groundwater monitoring or soil monitoring **Remediation**: Further investigation to assess the cause of the leak. If warranted, re-enter the well, re-establish well integrity and decommission. **Potential for enduring well integrity issue**: Dependent on source of the leak, which would require detailed assessment to determine.

7.1 Scenario 1 : Casing corrosion within reservoir and aquitard

7.1.1 Description

In this scenario, the steel casing (production casing) has been corroded within the reservoir with the corrosion extending into the overlying aquitard. This corrosion (casing failure) has caused cavities which penetrate the full thickness of the steel casing allowing fluids and gasses to travel between the inner annulus to the cement sheath.

If left un-remediated the exposure of the cement sheath to fluids from inside the well could potentially lead to a well integrity breach in the reservoir or overlying aquitard.

7.1.2 General information

The well is a vertical well at the end of its operational life and is being prepared for decommissioning.

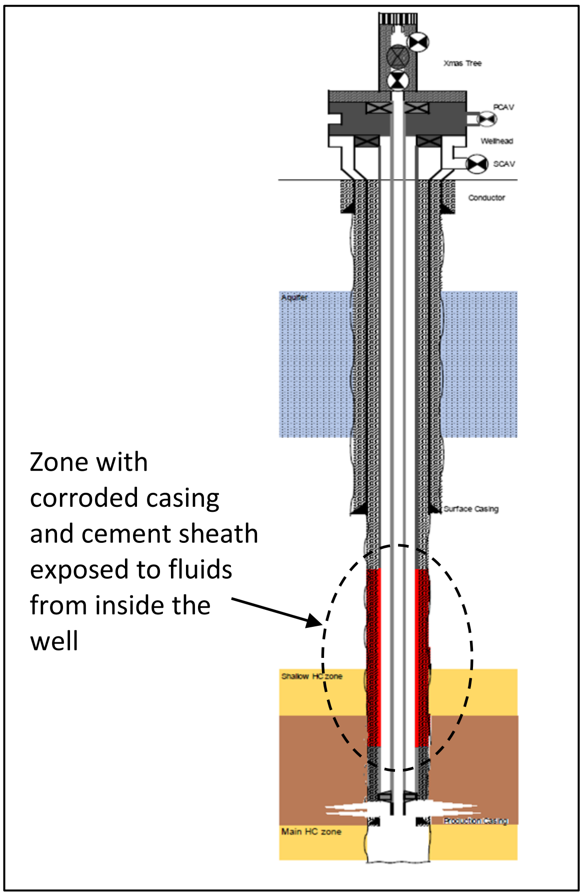

Figure 23 - Sketch of Scenario 1: Casing corrosion within reservoir and aquitard.

7.1.3 Monitoring and remediation strategy

Preparing for stage 1 decommissioning

Monitoring / Detection: The condition of the steel casing well component can be monitored by a range of downhole logging tools which are lowered into the well to investigate the status of the well barriers. The downhole logging tools which could pick up deterioration of the steel casing include: calliper logs, real-time compaction imager (RTCI), and borehole ultrasonic casing imaging (UCI). As shown in Figure 18, these downhole logs are able to be run before the installation of the aquifer cement plugs (Preparing for decommissioning). If these logs were run, there would be a high chance that downhole logs would detect this steel casing degradation as shown in Table 2.

As the steel casing degradation in this scenario does not reach the surface, and the integrity of cement is assumed to be intact, the wellhead pressure gauges would not be effective in detecting this well integrity issue.

Remediation: Different technologies, including casing patches, expandable liners, conventional liners, straddle packers, and tubing patches, could be implemented to repair damaged casing ahead of stage 1 decommissioning.

After stage 1 decommissioning

Monitoring / Detection: After the cement plugs have been placed across all identified hydrocarbon bearing formations and aquifers, direct monitoring of casing corrosion below the cement plugs is no longer possible.

As the steel casing degradation in this scenario does not reach the surface, the wellhead pressure gauges would not be effective in detecting this well integrity issue.

It is unlikely that this the steel casing degradation in this scenario would be detected unless the issue was exacerbated.

Remediation: No remediation options are available while there are cement plugs installed across the aquifer intervals.

7.1.4 Anticipated well integrity outcome

It is **possible** that the well in this scenario could have an enduring well integrity issue. Because the damage to the steel casing is limited to the reservoir and aquitard it would not be detected with surface pressure gauge or annular pressure testing. If well logs did not detect the issue before stage 1 decommissioning, then it is likely the issue would remain undetected.

However, the failure of the steel casing well barrier component in the reservoir or aquitard would not lead to a contamination of groundwater or release of gas to atmosphere without further well barrier element failures.

7.2 Scenario 2 : Cement bond failure from reservoir to aquifer

7.2.1 Description

In this scenario, the cement bond between the outer wall of the cement sheath and the formation has degraded (creation of micro-annuli). These micro-annuli extend from the shallow hydrocarbon zone to the overlying aquifer.

If left un-remediated, this micro-annuli which extends between a permeable layer (source) to the overlying aquifer (environmental endpoint) could potentially provide a pathway through which fluids could travel. The potential for aquifer contamination in this scenario would depend on the driving forces (pressure gradient, fluid buoyancy, etc) and the ability of fluid and gasses to flow from the source interval.

7.2.2 General information

The well is a vertical conventional well at the end of its operational life and is being prepared for decommissioning.

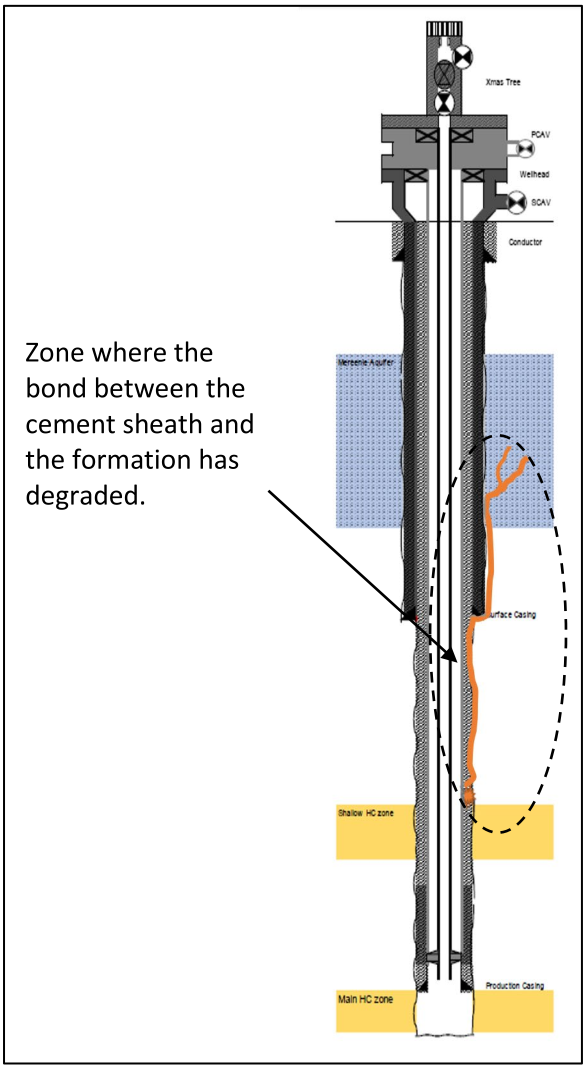

Figure 24 - Sketch of Scenario 2: Cement bond failure from reservoir to aquifer.

7.2.3 Monitoring and remediation strategy

Preparing for stage 1 decommissioning

Monitoring / Detection: The integrity of the cement sheath bond to the surrounding formation can be monitored by downhole logging tools which are lowered into the well to investigate the status of the well barriers. The main downhole logging tool which would pick up deterioration of the cement sheath bond is a cement bond log (CBL). As shown in Figure 18, this downhole log is able to be run until the installation of the aquifer cement plugs (Preparing for decommissioning). There is a high chance that a cement bond log would detect this delamination of the cement sheath bond from the surrounding formation as shown in Table 2 if run prior to decommissioning.

Remediation: Before the stage 1 decommissioning is undertaken, the delamination of the cement sheath from the surrounding formation could potentially be remediated by cement squeezing following up with the cement bond integrity testing.

After stage 1 decommissioning

Monitoring / Detection: After the cement plugs have been placed across the hydrocarbon bearing formations and aquifers, direct monitoring of micro-annuli delamination below the cement plugs is no longer possible.

As the delamination of the cement sheath bond from the surrounding formation in this scenario does not reach the surface, the wellhead pressure gauges would not be effective in detecting this well integrity issue.

It is unlikely that the delamination of the cement sheath bond from the surrounding formation in this scenario would be detected between stage 1 and stage 2 decommissioning.

Remediation: No remediation options are available while there are cement plugs installed across the aquifer intervals.

After wellhead removal

Monitoring / Detection: After the wellhead has been removed in stage 2 decommissioning, direct monitoring of micro-annuli delamination is no longer possible.

As shown in Table 2, after the wellhead has been removed, the monitoring options are limited to indirect monitoring techniques such as groundwater or atmospheric monitoring, flux chamber measurements and soil monitoring. The ability for these techniques to identify and diagnose a micro-annuli delamination between the reservoir and an overlying aquifer is very limited.

It is unlikely that the micro-annuli delamination between the reservoir and an overlying aquifer in this scenario would be detected after the removal of the wellhead (after stage 2 decommissioning).

Remediation: No remediation options are available while there are cement plugs installed across the aquifer intervals.

7.2.4 Anticipated well integrity outcome

It is **plausible** that the well in this scenario could have an enduring well integrity issue. If the micro-annuli delamination was not detected and remediated ahead of stage 1 decommissioning there is little chance of monitoring being able to detect the micro-annuli delamination once the downhole plugs are installed.

As the micro-annuli delamination had propagated from the reservoir to the aquifer a pathway may exist from the source to the environmental endpoint. If a driving force exists (pressure gradient, fluid buoyancy, etc) to encourage fluid or gas movement along the pathway and contaminants are able to flow from the source interval at a sufficient rate then it is possible that contaminants could enter the aquifer due to this well integrity failure.

7.3 Scenario 3 : Cement sheath failure within reservoir

7.3.1 Description

In this scenario, the cement sheath surrounding the steel casing in the horizontal section of an unconventional petroleum well has developed cracks due to pressure differences between the reservoir and the inner annulus. This cement sheath failure is contained to the reservoir.

If left un-remediated, fluids from the reservoir could contact the steel casing and cement in the horizontal section of the well and potentially lead to local degradation of these well barrier components.

7.3.2 General information

The well is a horizontal unconventional well at the end of its operational life and is being prepared for decommissioning.

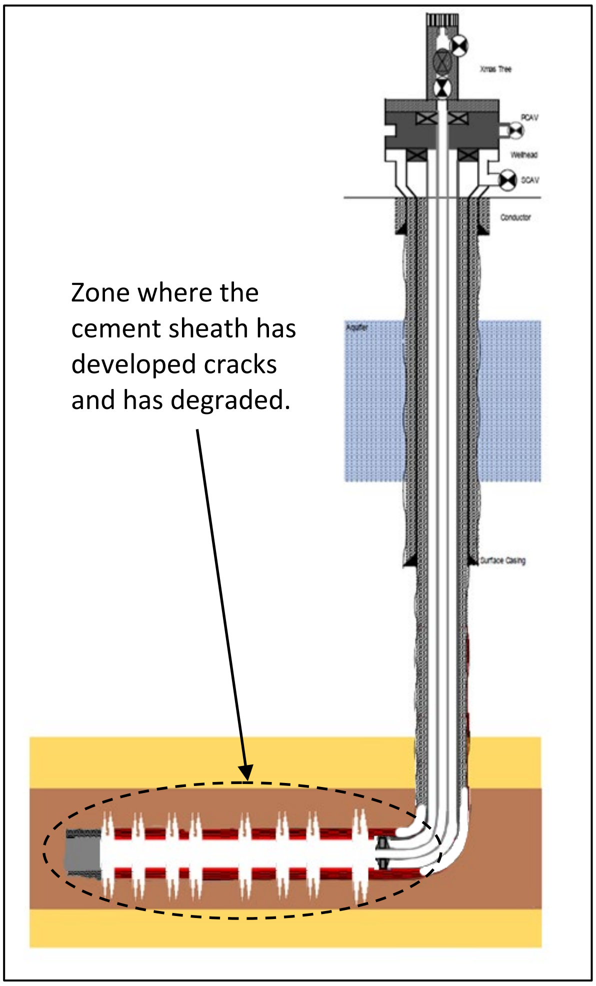

Figure 25 - Sketch of Scenario 3: Cement sheath failure in reservoir.

7.3.3 Monitoring and remediation strategy

Preparing for stage 1 decommissioning

Monitoring / Detection The integrity of the cement sheath can be monitored by downhole logging tools which are lowered into the well to investigate the status of the well barriers. The main downhole logging tools which could detect deterioration of the cement sheath are cement bond log (CBL), variable density log (VDL), ultrasonic imaging tool (USIT), and segmented bond tool (SBT). As shown in Figure 18, these downhole logs are able to be run up to the point of installation of the aquifer cement plugs (Preparing for decommissioning). There is a high chance that these downhole logs would detect this deterioration of the cement sheath (as shown in Table 2) if they were run prior to decommissioning.

Remediation: Prior to stage 1 decommissioning, the deterioration of the cement sheath can potentially be remediated by squeezing new cement into the area and validated with integrity testing and potentially downhole logging tools.

After stage 1 decommissioning

After the cement plugs are installed in the reservoir, access to run downhole logs is unavailable to the section of the well with the failed cement sheath. Therefore this failure is unable to be monitored or remediated after stage 1 decommissioning without significant additional work (drilling out the cement plugs to re-access the well).

7.3.4 Anticipated well integrity outcome

This failure mode is **not anticipated** to lead to an enduring well integrity issue as the damage to the cement sheath well barrier component is limited to within the reservoir. It is likely this failure would not be detected after stage 1 decommissioning had been undertaken as there would be no indication with surface pressure gauges or annular pressure testing. However, the failure of the cement casing within the reservoir would not lead to contaminant entering environmental endpoints (groundwater or escaping to surface).

7.4 Scenario 4 : Production tubing failure

7.4.1 Description

In this scenario, the production tubing has degraded allowing fluids to flow between the inside of the production tubing and the inner annulus of the well. This physical degradation of the production tubing may occur due to imposed stresses from temperature, pressure and fluid composition cycles (i.e. through wear, corrosion, and/or erosion).

If left un-remediated, this failure of the produciton tubing could expose the inner annulus of the well to unanticipated fluids.

7.4.2 General information

The well is a vertical conventional well at the end of its operational life and is being prepared for decommissioning.

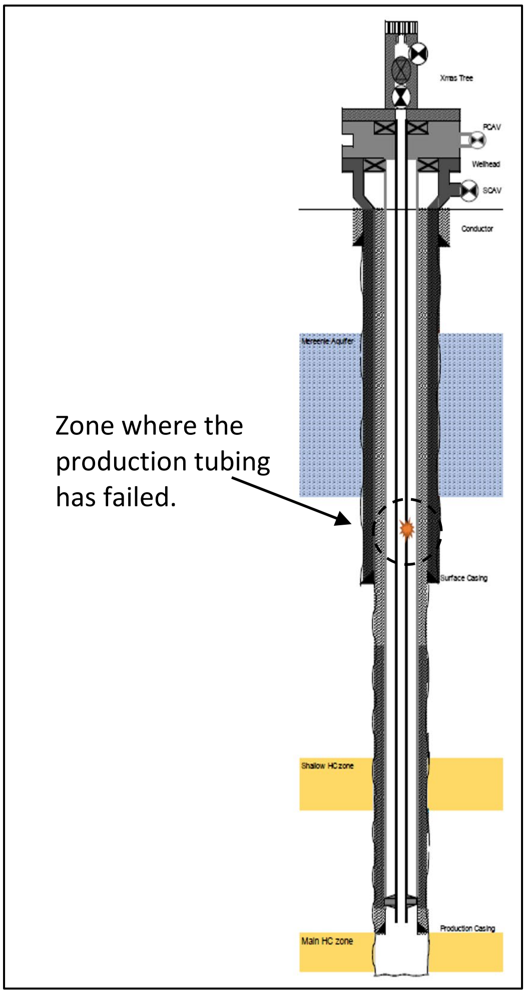

Figure 26 - Sketch of Scenario 4: Production tubing failure.

7.4.3 Monitoring and remediation strategy

Preparing for stage 1 decommissioning

Monitoring / Detection: A failure through the production tubing would typically be detected by wellhead pressure gauges before preparing for decommissioning (assuming there is pressure/driving force within the production tubing).

Remediation: As the production tubing will be removed to prepare the well for decommissioning, no remediation is required in this instance.

7.4.4 Anticipated well integrity outcome

The well in this scenario could have **no enduring well integrity issue** as the damaged production tubing will be removed prior to decommissioning.

7.5 Scenario 5 : Reservoir cement plug failure after decommissioning stage 1

7.5.1 Description

In this scenario, there is a leak through the reservoir cement plug installed during stage 1 decommissioning.

If left un-remediated there will be a potential risk of fluids leaking up the inside of the decommissioned well and pressurising the cement plug set over the aquifer.

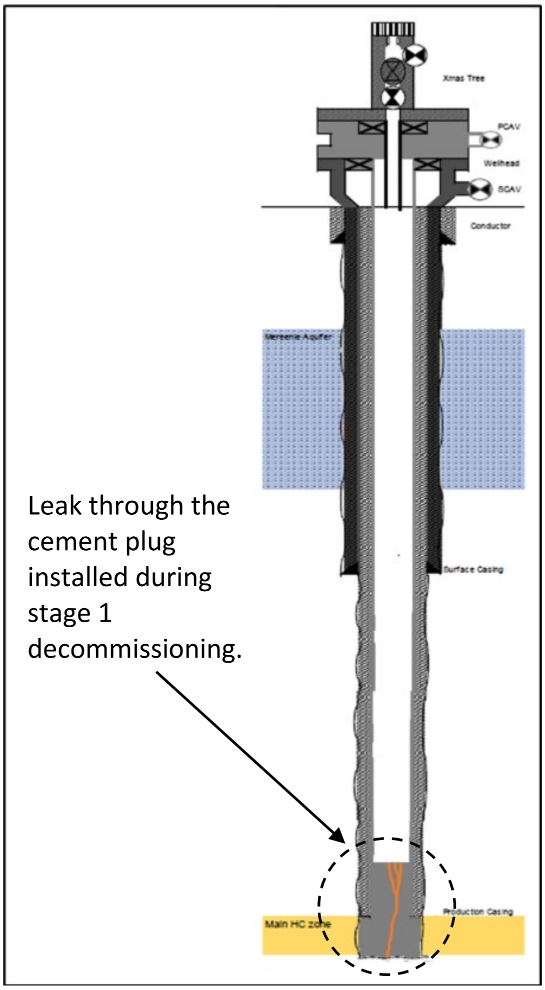

Figure 27: Sketch of Scenario 4: Cement plug failure after stage 1 decommissioning.

7.5.2 General information

The well is a vertical unconventional well at the end of its operational life and is being prepared for decommissioning.

7.5.3 Monitoring and remediation strategy

Preparing for stage 1 decommissioning

All the well barrier elements have a history of successful integrity test performance. No issues were detected in tests run while preparing the well for decommissioning. This well was deemed ready for stage 1 decommissioning.

During stage 1 decommissioning operations

Monitoring / Detection: The reservoir cement plug would be placed across the hydrocarbon bearing formation during stage 1 decommissioning. A failure in the cement plug could be identified through cement plug integrity testing (a positive or a negative pressure test).

Remediation: The failed cement plug would be removed, and a new cement plug set and tested in its place.

After stage 1 decommissioning

Monitoring / Detection: If the cement plugs over the aquifers were also placed during stage 1 decommissioning and the initial test of the reservoir cement plug failed to identify any issues then it would not be possible to detect failure in the lower reservoir cement plug after stage 1 decommissioning.

7.5.4 Anticipated well integrity outcome

If the failure in the reservoir plug was identified in pressure testing prior to the installation of the aquifer plug and the failed reservoir plug removed and replaced, there would be **no enduring well integrity issue** from this failure.

However, if the failure in the reservoir plug was not identified prior to the installation of the aquifer plug then the well integrity failure could remain undetected and has the potential to expose the aquifer plug and the other well components to fluid and pressure from the reservoir interval.

7.6 Scenario 6 : Leakage detected after decommissioning

7.6.1 Description

In this scenario, the decommissioning process has been complete, and the wellhead has been removed. However, fluid leakage at the surface has been detected through surface monitoring (Visual inspection or soil monitoring). This scenario could apply to a relinquished/orphan well.

If left un-remediated there will be a potential risk of ongoing contamination of the surrounding environmental endpoints (soil, surface water shallow groundwater).

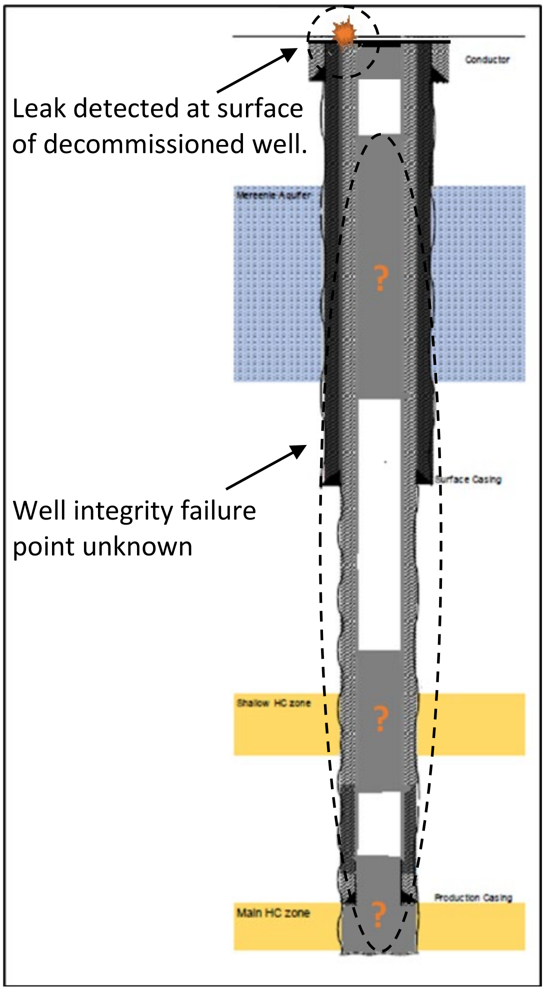

Figure 28: Sketch of Scenario 6: Leak detected after decommissioning

7.6.2 General information

The well is a decommissioned vertical unconventional well.

7.6.3 Monitoring and remediation strategy

After stage 2 decommissioning

Monitoring / Detection: The well had not shown any sign of integrity issue or barrier element failure prior to decommissioning however indirect monitoring (gas detector, visual inspections, groundwater monitoring or soil monitoring) has identified local contamination at the site of the buried wellhead.

The indirect monitoring methods have been successful in this case in identifying a leak from compromised well integrity however they are not able to identify the source of the leak.

Remediation: As the surface plug has been installed, the wellhead has been removed, and surface casing cut, there is no easy access to the well. Further investigation would be required to determine whether the leak posed a risk that warranted access to the well being re-established (along with the associated risks). These investigations could involve detailed monitoring and sampling to provide more information about the nature and extent of the leak, a review of the well and its history to determine potential failure points and an assessment of the risks associated with re-entering the well.

To re-enter the well, the steel cap and surface cement plug need to be removed, a wellhead fitted and pressure control re-established for the well. After access to the well is re-established, the integrity of the well could be investigated and any remedial work required undertaken.

7.6.4 Anticipated well integrity outcome

As the contamination of the local environment was identified by indirect monitoring, the source of the leak is unknown. Further investigation would be required to determine the extent of the leak and to determine if re-establishing access to the well is warranted.

8 Conclusions

This project has investigated options for long term monitoring of decommissioned wells. The approach taken follows current industry and regulatory best practice to consider well integrity throughout the well's lifecycle, from design through construction, operation and ultimately decommissioning. As monitoring is only required where there is a risk of a failure that could lead to impact, the project considered the risks to the integrity of decommissioned wells. The conclusion of this risk assessment was that long term integrity risks to decommissioned wells can be foreseen and managed during the operating life of a well. Decommissioned wells will no longer be subjected to operational stresses but may be subjected to geological, chemical, and hydraulic stresses from the surrounding environment interacting with the well components. Decommissioning activities can be designed to maximise the integrity of the well barriers installed during decommissioning.

Monitoring of the performance of well barriers during a staged decommissioning approach allows their performance to be confirmed, and more importantly, remedial action can be taken while there is still access to the well. There are a large range of monitoring methods available for assessing the well integrity of an operating well where there is still access, and there is active development in this field.

There has been limited development of monitoring technology for decommissioned wells. A key challenge is that for a well to be considered to be fully decommissioned, there will no longer be access to the downhole components of the well. This removes the ability to conduct preventative monitoring to predict a future failure, and only allows monitoring for the impacts of failures. High sensitivity methane monitoring equipment are likely to provide the best means of monitoring for decommissioned well integrity failures that impact the surface environment and there are a number of commercially available suppliers. These methods would allow a methane anomaly to be detected, indicating a potential well integrity issue warranting further investigation. Similarly groundwater monititoring can be used to detect changes to groundwater quality (dissolved methane content and electrical conductivity are potential indicators).

There are advanced methods that can be applied to investigating the source of any methane anomaly or changes to groundwater quality. These include sampling for isotopic analyses and presence of other hydrocarbons.

Fibre-optic based monitoring has been considered as a technology that may allow long-term down-hole monitoring of decommissioned wells. However, it has high cost, significant effort required to undertake data analysis, uncertainty about the significance of data collected, and the requirement to have a permanent surface equipment installation preventing full remediation of the site. The longevity of the fibre in the well is unknown, and the long-term impact on well integrity of having the fibre embedded in the cement sheath of cement plugs is unknown. Further research would be required to resolve these issues before the use of fibre-optic based monitoring methods could be considered for long term monitoring.

Table 5 sets out a summary of decommissioned well monitoring from a well lifecycle point of view. Monitoring post decommissioning is valuable in providing assurance that decommissioned wells are not causing a significant environmental impact. However monitoring does not replace the need for ensuring a high degree of well integrity at the time of decommissioning

Table 5: Summary of decommissioned well mionitoring. Green text reporesents proactive monitoring where remediation can readily be conducted.

	Wells yet to be decommissioned	Relinquished (orphan wells).
Why monitor	• to demonstrate well barrier elements are meeting performance requirements to maintain well integrity post decommissioning • to detect any well integrity leaks post decommissioning	• to detect any well integrity leaks post decommissioning
When to monitor	• during the operating life of the well • immediately prior to decommissioning to validate well integrity • during decommissioning (stage 1) to validate integrity of barriers installed during decommissioning • long term periodic monitoring to detect any well integrity leaks	• long term periodic monitoring to detect any well integrity leaks
What to monitor	• validate well barrier elements against acceptance criteria • wellhead annular pressures to confirm successful decommissioning at stage 1 • methane near ground surface post decommissioning • groundwater quality (where a risk assessment determines saline water or liquid hydrocarbons may be mobile)	• methane near ground surface post decommissioning • groundwater quality (where a risk assessment determines saline water or liquid hydrocarbons may be mobile)
How to monitor	• well logs, well integrity tests, in-well instruments • wellhead pressure gauges • methane detectors at or immediately above ground surface with sensitivity of at least 0.1 ppm • groundwater electrical conductivity (in-situ) and dissolved methane (sampling)	• methane detectors at or immediately above ground surface with sensitivity of at least 0.1 ppm • groundwater electrical conductivity (in-situ) and dissolved methane (sampling)
Who monitors	• operator • operator up to relinquishment	• regulator post relinquishment

Long term monitoring (multiple decades to centuries) is a topic of interest in geological storage of carbon dioxide (Feitz et al., 2014; Jenkins, 2020b) and for nuclear waste repositories (Kuppler & Hocke, 2019). There are challenging questions around the timescales required for monitoring and the future governance of monitoring. Over this time frame many generations of professionals and citizens will have passed, institutions will change and technologies will evolve. Nuclear waste and carbon dioxide storage both involve disposal of waste material in the subsurface. A key difference for decommissioned petroleum wells is that they interact with a natural system. Continued monitoring of decommissioned wells may no longer be required where potential fluid movement along them is similar to the natural movement of fluid within the Earth's crust.

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1300 363 400
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For further information

1300 363 400
gisera@gisera.org.au
gisera.csiro.au

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