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Abstract

The petroleum industry uses a variety of qualitative risk assessment methods for maintaining well integrity, such as well barrier schematics and barrier diagrams. Identifying barriers and using well barrier schematics are helpful tools in qualitative risk assessments. However, it is not yet clear if these methods can be applied for risk assessments in the geothermal industry. Geothermal wells often produce directly through the casing, instead of through production tubing, making it difficult to identify two independent barrier envelopes in accordance to NORSOK D-010.

High temperatures and corrosion are the most common contributors to failure in geothermal wells. In this study, a hypothetical case of a downhole corrosion problem was assessed by means of conducting a qualitative risk analysis and identifying well barriers in a geothermal well.

This study shows that qualitative risk assessment methods from the petroleum industry are applicable using minor adjustments to well barrier interpretation and barrier diagrams. Using NORSOK D-010 as a guideline, the study found that typical Icelandic high temperature geothermal wells may consist of a primary and a secondary barrier envelope with a common well barrier element at the wellhead. At shallow depths, the intermediate casing, often the anchor casing, acts as a secondary barrier against an aquifer. In addition, the study indicates that production of low enthalpy fluids and its financial impact might be the main concerns of downhole corrosion problems close to the production casing shoe.

Findings in this study could form the foundation for raising the standard of risk assessment methods for high temperature geothermal wells, and the well barrier interpretations defined in this thesis may be suitable for a number of these types of wells.

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Kristi Larsdottir Kalvenes

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June, 2017

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Abbreviations

2-D	-	Two-dimensional
API	-	American Petroleum Institute
DHSV	-	Down Hole Safety Valve
EGS	-	Enhances Geothermal System
FE	-	Finite Element
FEM	-	Finite Element Model
ID	-	Inner Diameter
IDDP	-	Icelandic Deep Drilling Project
ISO	-	International Organization for Standardization
HDR	-	Hot Dry Rock
HTHP	-	High Temperature, High Pressure
LMV	-	Lower Master Valve
MD	-	Measured Depth
mpy	-	Mils per year
NCS	-	Norwegian Continental Shelf
NZS	-	New Zealand Standard
OD	-	Outer Diameter
TD	-	True Depth
UMV	-	Upper Master Valve
WBE	-	Well Barrier element
WBS	-	Well Barrier Schematic
WIMS	-	Well Integrity Management System

1. Introduction

Utilizing geothermal energy from the inner parts of the Earth to produce electricity involves extracting high temperature fluids such as water, gas or a mixture of these. It is desirable to drill in areas with a higher temperature gradient than the average gradient of approximately 25°C/km (Finger & Blankenship, 2010). There are ongoing research projects for reaching extreme temperatures. The goal is to reach a supercritical water level (374°C and 221 bars) to achieve a higher energy output, this requires drilling deeper than 3,5 km (G. Ó. Friðleifsson et al., 2014).

The geothermal technology is adapted from the petroleum industry and modified for high temperatures. Geothermal wells usually produce directly through the production casing and they often have a complete cement sheath to surface (Finger & Blankenship, 2010). Reducing the risk of uncontrolled release of formation fluids is necessary and relevant for both petroleum and geothermal industries. According to the reports from the GeoWell Project (Lohne, Ford, & Mansouri, 2016a, 2016b), the petroleum industry has a higher focus on maintaining well integrity compared to the geothermal industry. Also, they found the term barrier rarely mentioned in the reviewed publications and indicated that the focus on barriers and barrier reliability in the geothermal industry is limited.

The financial challenges related to geothermal energy are more severe than in the petroleum industry. The technology in the petroleum industry is more mature and the time from production to market is short for hydrocarbons. In contrast, a geothermal resource requires more construction and infrastructure related to electricity generation, or direct heating, before the energy can be utilized. In addition, the high temperatures and the corrosive fluids in the geothermal reservoirs require expensive equipment like high-grade casings and specific cement design (Lohne et al., 2016a, 2016b).

Utilization of geothermal resources relies strongly on the structural integrity of the casing. High temperatures in deep geothermal wells can increase the risk of casing failures. The increased interest in deep drilling makes the casing strength one of the limiting factors due to the higher pressures, higher temperatures and challenging corrosive environments (Kaldal, Jonsson, Palsson, & Karlsdottir, 2015). The casing is subjected to thermal cycling during production. As the casing is generally cemented to surface, thermal cycling may cause large stresses resulting in casing or connections exceeding their yield limit (Maruyama, Tsuru, Ogasawara, Inoue, & Peters, 1990). The thermal cyclic loads may also create cracks in the cement breaking the bond between casing and cement, allowing corrosive fluids to attack the casing wall (Kosinowski & Teodoriu, 2012). The reservoir environment can be highly corrosive with substances such as carbon dioxide (CO_2) and hydrogen sulphide (H_2S) often present and this can be detrimental to production casing, cement and wellhead (Shadravan & Shine, 2015).

1.1 *Background of the Problem*

Wang, Yan, Li, Hu, and Li (2016) investigated the possibility to utilize geothermal energy from abandoned oil and gas wells to cover the heat demand in oilfields, replacing fossil fuels. They found that exploitation of these resources is limited by various factors such as "lack of overall planning, economic assessment, and lack of norms and standards of geothermal energy exploration and resource assessment".

Geothermal wells are often drilled with adherence to local petroleum regulations and standards such as the American Petroleum Institute (API) (Lohne et al., 2016a, 2016b). In addition, Code of Practice for Deep Geothermal Wells, NZS 2403:2015, is frequently used when designing geothermal wells

(Southon, 2005). The petroleum industry has a high focus on well integrity and well integrity management systems (WIMS). It is highly regulated with guidelines such as the NORSOK D-010 (D-010:2013, 2017) standard covering well integrity on the Norwegian Continental Shelf (NCS) (Lohne et al., 2016a, 2016b).

Shadravan and Shine (2015) found that geothermal wells need to be considered as a complete structure in long-term zonal isolation throughout the life-cycle of a well, well design, barriers, field execution strategies and sustainability measures. Furthermore, they suggested that a WIMS could consider the effects of the well events on zonal isolation throughout the operational phase.

1.2 *Statement of the Problem (Research Questions)*

In geothermal wells, there are few regulations related to risk assessment. Lohne et al. (2016b) indicated that it is difficult to establish common technical standards and lessons learned across the geothermal industry due to the less collaborative community, and the limited mentioning of the term barrier in geothermal literature. In the oil and gas industry, definitions of barrier and barrier elements for each well are amongst the key areas in the risk assessment (Lohne et al., 2016b).

Published papers related to well integrity in the petroleum industry include a variety of qualitative risk assessment methods (Bower-white, 2012; Dethlefs & Chastain, 2012; Okstad & Sangesland, 2009; Utvik & Jahre-Nilsen, 2016). The goal of the risk assessment is to assess the well barriers, analyse the failure modes and determine the likelihood and consequence of a failure (Dethlefs & Chastain, 2012). It is not yet clear if these methods can be applied for risk assessments in the geothermal industry.

1.2.1 Hypothesis

It may be useful to apply qualitative risk assessment methods from the petroleum industry to support risk assessment in geothermal wells.

It is possible to hypothesise that there are common denominators between petroleum wells and geothermal wells, and that NORSOK D-010 can be adapted accordingly to define well barriers for geothermal wells.

1.3 *Objectives and Scopes of the Study*

The objectives and scopes proposed for this study are:

- Investigate if risk assessment methods from the petroleum industry are applicable for the geothermal industry by establishing and conducting a qualitative risk assessment of a well integrity corrosion problem
- Investigate NORSOK D-010 applicability for geothermal wells and identify well barrier elements in a geothermal well design using NORSOK D-010

1.4 *Approach*

This thesis uses a qualitative method where the data is collected through a literature review and interviews with industry experts. This will form the foundation for a theoretical well integrity corrosion problem where risk assessment methods from the petroleum industry are applied.

1.5 *Significance of the Study*

The work of establishing a qualitative risk assessment approach and identifying well barriers in geothermal wells in this thesis will aid the work of the GeoWell project to raise the standard of risk assessment methods, aiming to propose a risk management framework for deep geothermal wells. The overall objective of the GeoWell project is to ensure increased well lifetime and economic viability of a geothermal project.

1.6 *Overview of Thesis Content*

The structure of the thesis and the objectives of every step are presented below and a schematic of topics in the thesis is presented in Figure 1-1:

- Chapter 2 – This chapter contains generic literature about geothermal energy to create an understanding of the subject in order to conduct a risk assessment of a well integrity problem. Geothermal well design is considered to allow identification of well barriers and application of risk assessment methods from the petroleum industry. Potential problems typically encountered in geothermal wells are assessed with a special focus on corrosion and some examples from existing geothermal fields are presented.
- Chapter 3 – This chapter addresses the approach used in this study, and presents the geothermal well that will be the subject of the risk assessment in Chapter 4.
- Chapter 4 – This chapter consists of a qualitative risk assessment using the method and well presented in Chapter 3. A selection of known well integrity issues for a production well in the production phase, is analysed and a hypothetical corrosion problem is assessed with the help of risk assessment tools and methods adapted from the petroleum industry.
- Chapter 5 – This chapter presents the findings from Chapter 4, and the ones related to the thesis objective are discussed.
- Chapter 6 – In this chapter a conclusion is made from the discussion in Chapter 5 and areas for further work is suggested.

Figure 1-1 Schematic of topics in the thesis.

2 Geothermal Energy

2.1 *Introduction to Geothermal Energy*

The exploitation of geothermal energy is the extraction of natural thermal energy from within the Earth. This is an environmentally friendly and renewable source of energy, and one of the advantages of this resource is its reliability (Ganguly & Kumar, 2012). Geothermal resources have been identified in over 80 countries across the world (I. B. Fridleifsson, 2001). Within the Earth's crust the temperature increases with depth and the average temperature gradient is approximately 25°C/km (Finger & Blankenship, 2010). This means that at a depth of 3 km the temperature can be estimated to be around 90°C, assuming the surface temperature is 15°C. This heat source is usually classified as a low-temperature system and normally provides temperatures below 100°C at economic depths. In areas with magmatic intrusion the temperatures could reach in excess of 400°C (Dickson & Fanelli, 2001).

According to Hochstein (1990), a geothermal system can be described as "convective water in the upper crust of Earth, which, in a confined space, transfers heat from a heat source to a heat sink, usually the free surface". Furthermore, Dickson and Fanelli (2001) added that "a geothermal system is made up of three main elements: a heat source, a reservoir and a fluid, which is the carrier that transfers the heat". The fluid often originates from the reservoir, but in the case of low permeability or no in-situ fluid, cooler fluid is injected into the reservoir to gain heat (Finger & Blankenship, 2010). High temperatures and thermal expansion of fluids in a gravity field creates a natural convection. The heated, low-density fluid in the reservoir rises from the bottom of the system and is replaced by cooler fluid with higher density (Dickson & Fanelli, 2001). This process together with a typical geothermal system is presented in Figure 2-1.

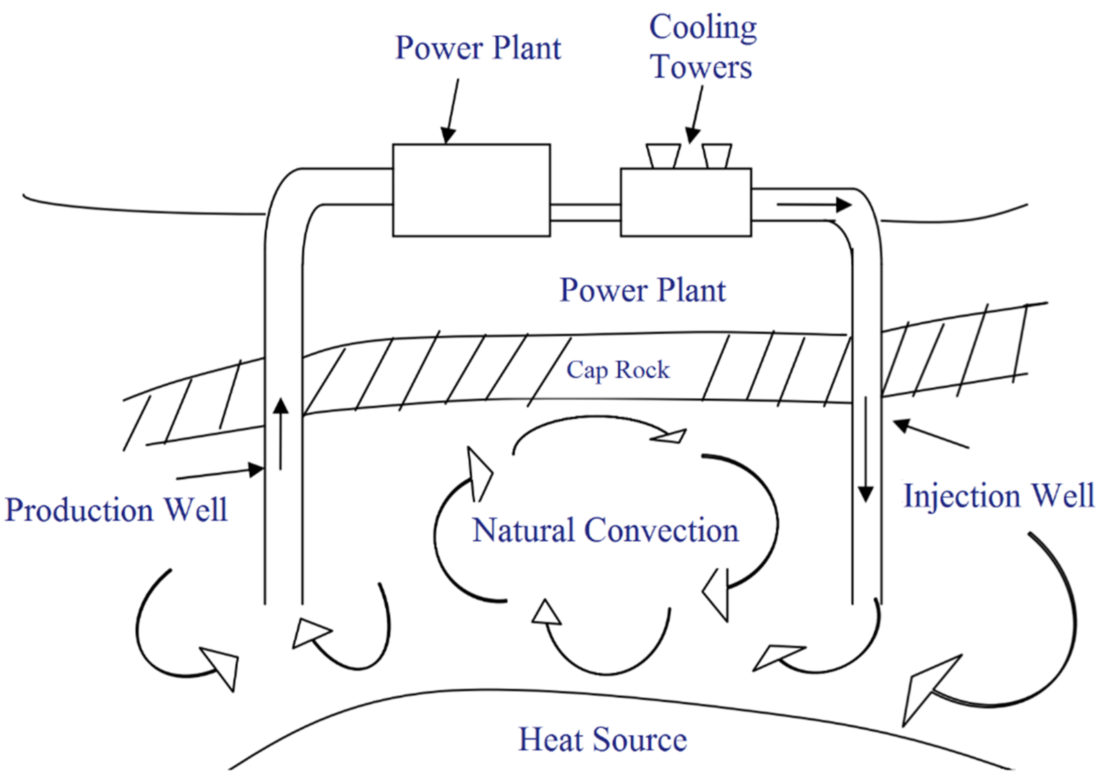


Figure 2-1 Schematic of a typical geothermal system (Ganguly & Kumar, 2012).

Faust and Mercer (1979) divided potential sources of geothermal energy into three major systems:

- *Hydrothermal* - Heat sources such as magmatic intrusions in the near surface area that transmit the heat to a porous rock and the fluid within by conductive and convective processes. This can be classified further with liquid or vapour dominated systems (White, Muffler, & Truesdell, 1971)
- *Geopressured* - A static system where fluid is trapped in permeable sedimentary rocks that are covered by a low permeable rock layer and exposed to high temperature and pressure.
- *Hot, Dry Rock (HDR)* – Low-permeable hot igneous rocks are heated in a similar way as the hydrothermal. An injection well transfers cold fluid down through a drilled borehole to fractures in the rocks where it absorbs heat. A production well transports the heated fluid back to surface.

These major systems can be further classified depending on their reservoir equilibrium state. Dynamic systems transfer heat through a continuous discharge and recharge of water where the water circulates through the system. In a static system, the heat is transferred through conduction as there is a minimum of recharge into the system (Ganguly & Kumar, 2012).

Oil and gas reservoirs are commonly found in sedimentary formations, while geothermal reservoirs often consist of igneous rocks that are normally more challenging and slower to drill, which affects costs (Lukawski et al., 2014). The formations are often hard, abrasive, highly fractured and under-pressured. Common rock types are (Finger & Blankenship, 2010):

- Granite
- Granodiorite
- Quartzite
- Greywacke
- Basalt
- Rhyolite
- Volcanic tuff

The heat from geothermal energy can be utilized directly or to produce electricity. Generation of electricity from geothermal energy usually demands drilling of wells that are commonly shallower than 4 km (Finger & Blankenship, 2010). According to I. B. Fridleifsson (2001), geothermal resources suitable for electricity production usually have temperatures above 150°C. In geothermal reservoirs, the temperatures can reach over 300°C (Finger & Blankenship, 2010). In comparison, petroleum reservoirs are generally classified as high temperature and high pressure (HTHP) when above 149°C and 690 bars (Shadravan & Amani, 2012).

The ongoing Icelandic Deep Drilling Project (IDDP) aim towards 4-5 km depths to reach water at a supercritical level (G. Ó. Friðleifsson et al., 2014). The critical level for pure water is at 374°C and 221 bars which means that it will be a hydrous gas that will not change phase in case of increase in temperatures at constant or increasing pressures. It will have much higher enthalpy and lower viscosity compared to a two-phase mixture of steam and water below beneath level (G. Ó. Fridleifsson & Albertsson, 2000).

The fluid in the geothermal system is usually water, but with high temperature and low pressure it can be in a liquid phase, vapour phase or a mixture of these (Finger & Blankenship, 2010). Most geothermal fluids originate from sea water or meteoric water leaving rocks, temperature, pressure and time as the primary variables. The chemistry from the geothermal fluids will therefore reveal information about reservoir lithology, temperature and in some cases water-rock ratios (DiPippo, 2016). H_2S and CO_2

gases are commonly present in geothermal systems and are highly corrosive (Finger & Blankenship, 2010). The geothermal fluids can be difficult to handle in operations due to the highly corrosive and scaling characteristics. Fluid composition varies in different wells and depends on factors like geology, temperature, pressure and water source. A system with a high water content contains large amounts of silica which may cause scaling problems, while a dry steam resource may have corrosion issues due to hydrogen chloride (HCl) and H_2S attacks. Also, both scaling and corrosion problems may occur simultaneously in some geothermal fields (Ocampo-Díaz, Valdez-Salaz, Shorr, Sauceda, & Rosas-González, 2005).

Enthalpy is a measurement of energy used to express the heat content of fluids transporting heat from the geothermal reservoir to surface. The temperature can be considered more or less proportional to enthalpy and this is commonly used for classifying the geothermal resources. Several authors have categorized the resources by dividing them into low, intermediate or high enthalpy (Dickson & Fanelli, 2001). In addition, Sanyal (2005) proposed a categorization focusing on relevant thermal boundaries, such that a temperature of 190°C is related to the ability of the geothermal wells to utilize a pump. An overview of these categorizations is presented in Figure 2-2 (Williams, Reed, & Anderson, 2011).

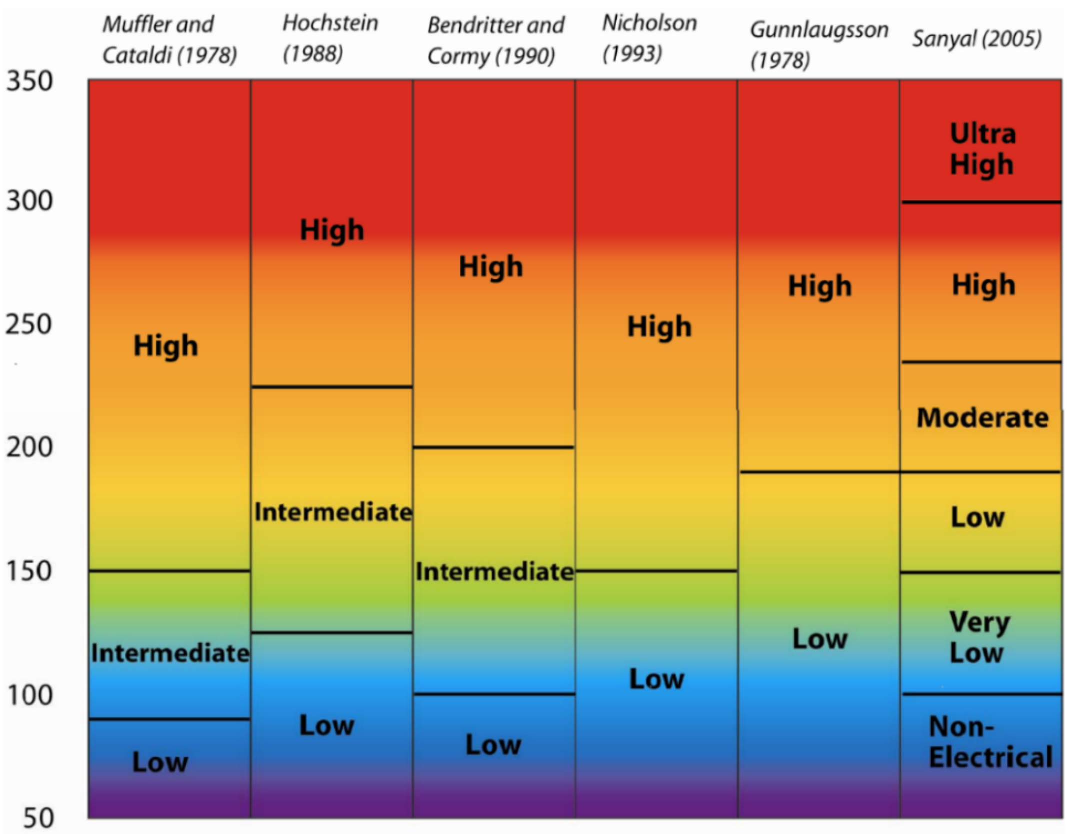


Figure 2-2 Classification of geothermal resources by temperature (Williams et al., 2011).

2.2 ***Risk of Geothermal Projects***

2.2.1 Financial Risk

Figure 2-3 shows the level of risk and investment in a geothermal development process (DiPippo, 2016). It is difficult to reduce the risk significantly in the early phases of a geothermal project. As the graph indicates, it is only after the well targeting and initial drilling you will start seeing a substantial reduction in the risk. It can therefore be discouraging for companies and institutes to invest in the development of geothermal projects. In these early phases it is important with a willingness to invest, both from governments and private investors, to help drive the development of geothermal resources forward and reduce the associated risk.

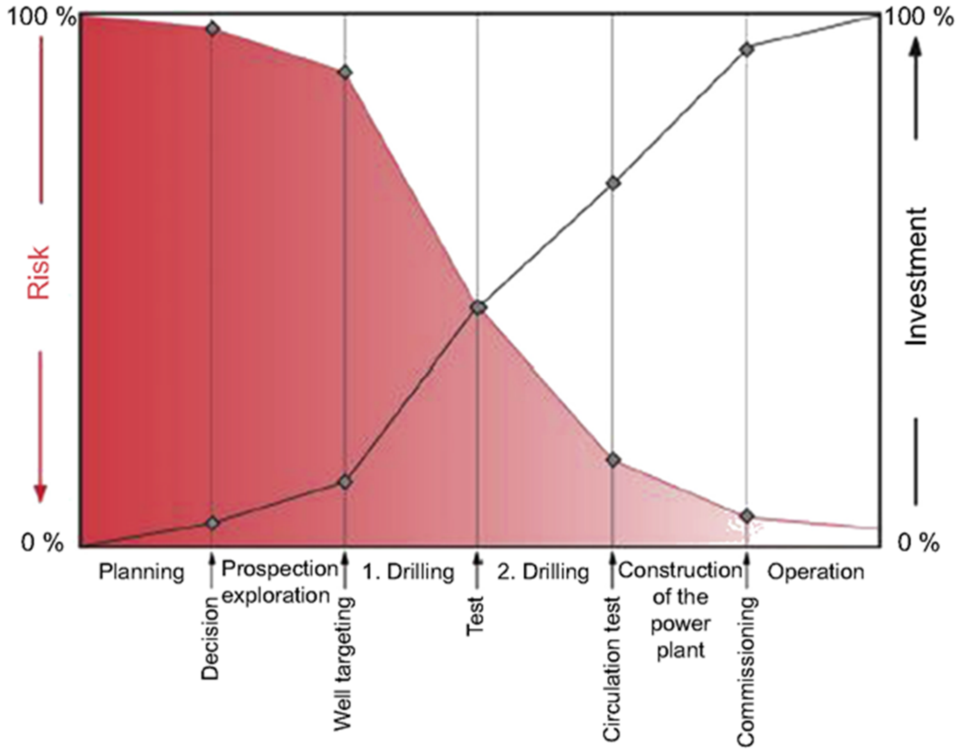


Figure 2-3 Risk of a geothermal project versus time (DiPippo, 2016).

In the development of geothermal projects, the well costs commonly make up 30-50% of the total project cost. More challenging wells that are being drilled cause a cost increase due to deeper wells, directional drilling and larger casings (Thorhallsson, 2008).

Development of reservoir interpretation technology has increased the understanding of reservoir behaviour and reduced the uncertainty related to exploration. Together with improved drilling technology the initial capital expense of a geothermal project may be reduced. In addition, a reduction in operational cost could be achieved with optimized management of the reservoir (Younger, 2015).

There are certain distinctive factors in the drilling activities affecting cost of deep geothermal wells. The analysis by Lukawski, Silverman, and Tester (2016) highlighted that more challenging drilling environments increase the well cost exponentially with depth. Also, a greater probability of complications due to more uncertain drilling conditions will increase the uncertainty of the well costs. In a cost probability distribution for deep geothermal wells the increased trouble time will manifest itself as a distribution centred around a higher cost and with a relative probability that stretches further into higher cost regions as shown in Figure 2-4 (Lukawski et al., 2016). In other words you may say that the deeper the well, the more difficult the well cost estimation will be.

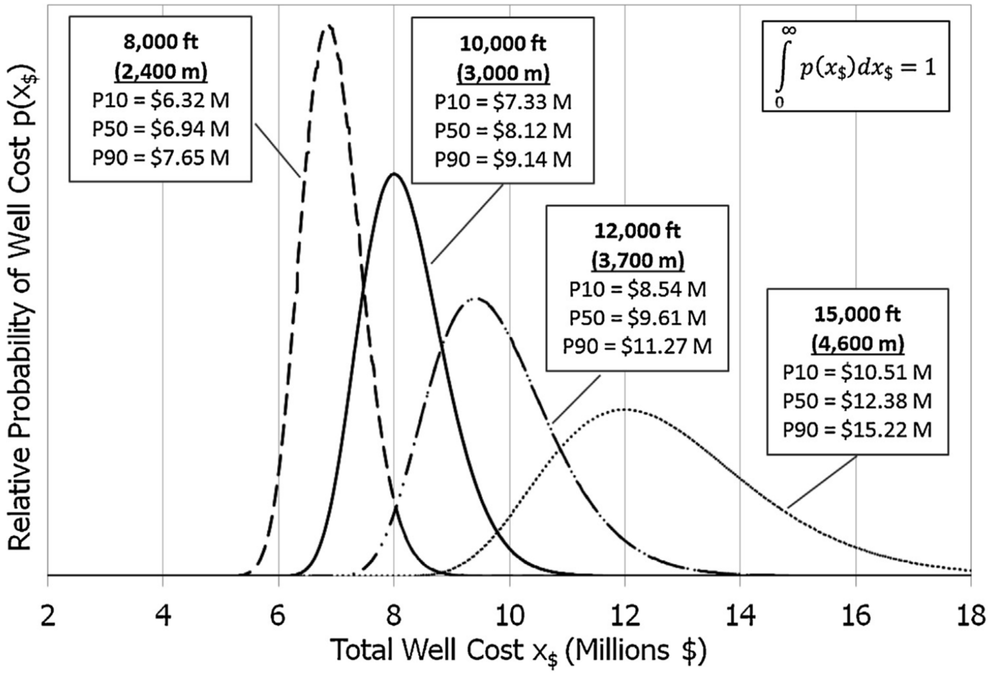


Figure 2-4 The probability of occurrence of a specific well cost p(x$) versus well cost is presented for wells with 4 different measured depths (MD) (Lukawski et al., 2016).

2.2.2 Risk of Zonal Isolation

Shadravan and Shine (2015) investigated the influence of high temperatures on cement as a barrier. A formation containing multiple reservoirs should be isolated to control flow. Cement that provides zonal isolation may be affected at different phases of well operation as illustrated in Figure 2-5. This shows that risk of zonal isolation is highest after completion. Each phase of the well life could affect the well barrier, from drilling to post-completion.

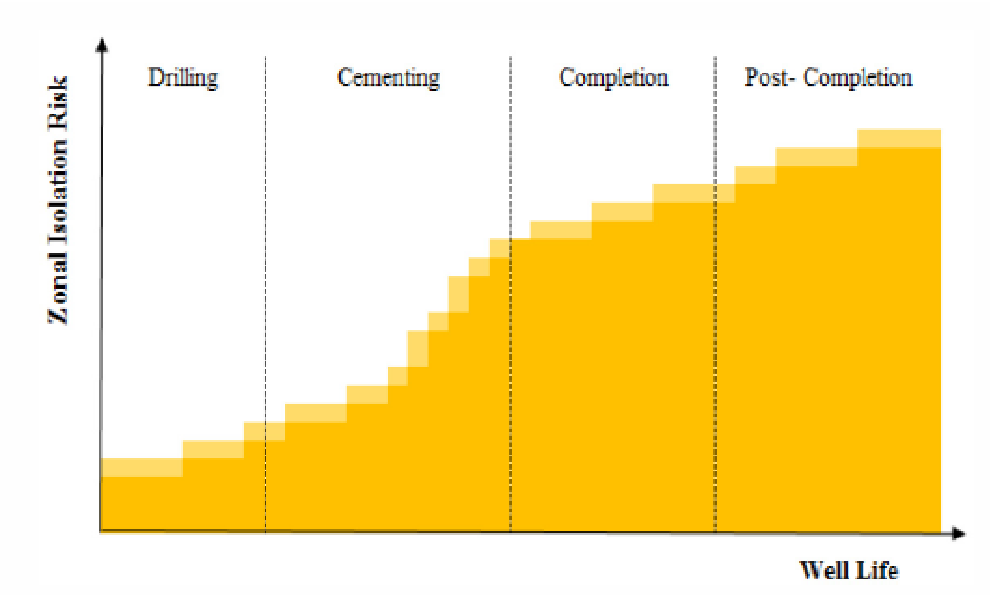


Figure 2-5 Risk of zonal isolation (Shadravan & Shine, 2015).

2.2.3 Environmental Risk

Harmful minerals and elements may be present in geothermal fluids and could pose a threat to humans, agriculture or wildlife during field development or normal operations. High temperature geofluids pose a higher threat to vegetation and aquifers as the quantity of dissolved solids increase substantially with temperature. The impact of a hypothetical release would depend on location, volume and chemistry of the emissions as well as the phase of the production fluids, explained in Table 2-1 (DiPippo, 2016).

Vapour phase		Liquid phase
Factor	**Impact**	**Factor**
CO_2	Climate and air quality	Boron, B
H_2S	Human health, safety and air quality	Arsenic, As and mercury, Hg
Benzene	Climate and air quality	Heavy metals
		Salt

Table 2-1 Overview of some elements and chemicals in geothermal fluids at atmospheric conditions

Summers, Gherini, and Chen (1980) investigated possible integrity failures that may lead to contamination of ground water from geothermal exploitation. If geothermal fluids are spilled to an aquifer, drinking water may be contaminated and also surface spills may be a threat to agriculture. In addition, geothermal fluids can carry heavy metals that are present in the soil. As illustrated in Figure 2-6, an aquifer may be contaminated due to migration from a reservoir, a surface pond, or through the well construction. Both production and injection wells may be responsible due to failure of casing or cement, or due to migration along the wellbore.

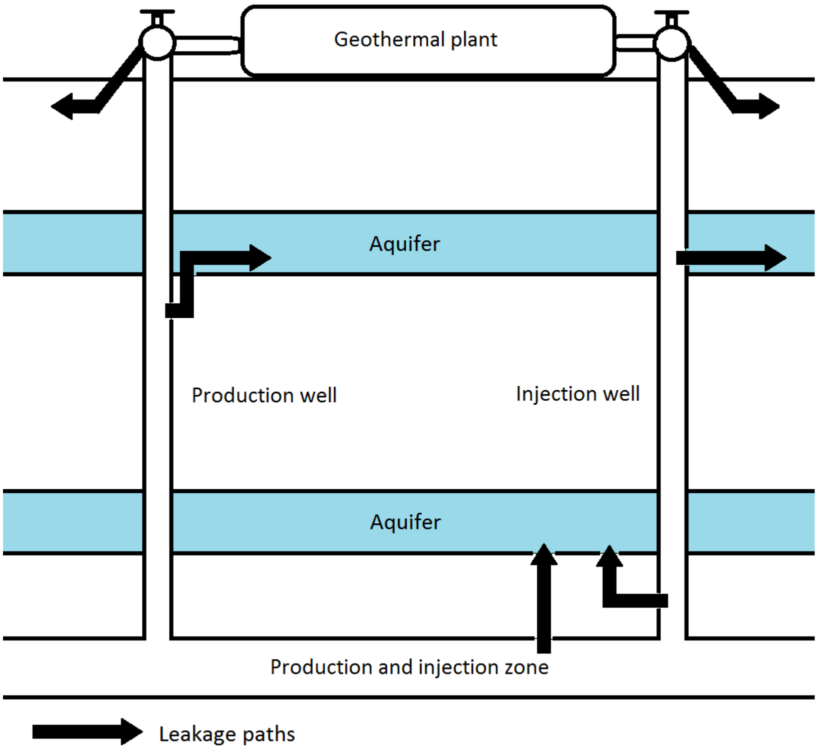


Figure 2-6 Hypothetical leakage paths adapted from Summers et al. (1980).

Previously, exploration of geothermal energy involved high risk of well blowouts during drilling. However, increased knowledge of site geology through modern technology together with today's blow out preventers (BOP), have reduced the potentially life-threatening risk significantly. In most geothermal fields the reservoir pressures are monitored, providing an early sign should a critical situation arise (DiPippo, 2016). However, before the chemical composition of geothermal fluids in a new field are thoroughly analysed, pressurized corrosive fluids could escape through the casing to the annulus, causing severe equipment damage and hazard to personnel in the vicinity. During drilling a BOP would not be able to prevent this from happening, and after completion of the well a BOP would not be present (DiPippo, 2016; Hodson-Clarke, Rudolf, Bour, & Russell, 2016).

2.3 *Geothermal Wells*

Geothermal technology is modified for high temperatures and larger well diameters from the petroleum industry (Finger & Blankenship, 2010). Teodoriu and Falcone (2009) stated that "casing fatigue and cement integrity are the key issues for geothermal wells since the desired lifetime is higher than for oil and gas". In the past, life expectancy of geothermal wells of 20 years was considered acceptable, however, they may be capable of producing for twice as long (Þórhallsson, 2003). According to S. Þórhallsson (personal communication, February 16, 2017), low-temperature wells (<100°C) maintain a stable output and are known to produce for over 60 years. High temperature wells (>200°C) decline gradually in output at a rate of approximately 2.5% per year. However, some of the earliest deep wells from 1960 in Hveragerði, Iceland are still producing. Þórhallsson (2003) and (Teodoriu & Falcone, 2009) reported that the most efficient way of extending longevity of the wells is to keep the wells hot in order to minimize thermal cycling.

2.3.1 Well Design

Well design depends on the purpose of the well. A production well might require more attention to material strength and larger diameter size than an exploration well. Geothermal wells often produce water, steam or both directly through the casing, instead of through production tubing which is common in oil and gas wells (Finger & Blankenship, 2010). There are several reasons for a tubing to be a disadvantage in geothermal wells. In case the tubing needs to be removed, killing the well will cause a temperature shock on the casing. Also, structural problems due to high velocities in the tubing and reduction of well flow might be an issue (Ingason et al., 2015).

The purpose of the casing design is to (NZS 2403:2015, 2015; Thorhallsson, 2008):

- Seal out unwanted aquifers
- Contain well fluids
- Support the hole
- Allow control of blow-outs
- Support drilling and anchor the wellhead
- Provide a conduit for the well production
- Protect the integrity of the well against corrosion, erosion, or fracturing

Geothermal wells usually include two to five cemented casing strings and a slotted liner (Thorhallsson, 2008). To minimize the risk of buckling and expansion of the casing, a complete cement sheath over the full length of the casing is often required (Hole, 2008; Shadravan & Shine, 2015). In a vertical well, a liner is not cemented or connected to the production casing. It is placed at TD, leaving the annulus between the production casing and the liner open, Mannvit (personal communication, April 18, 2017). A typical well design is presented in Figure 2-7.

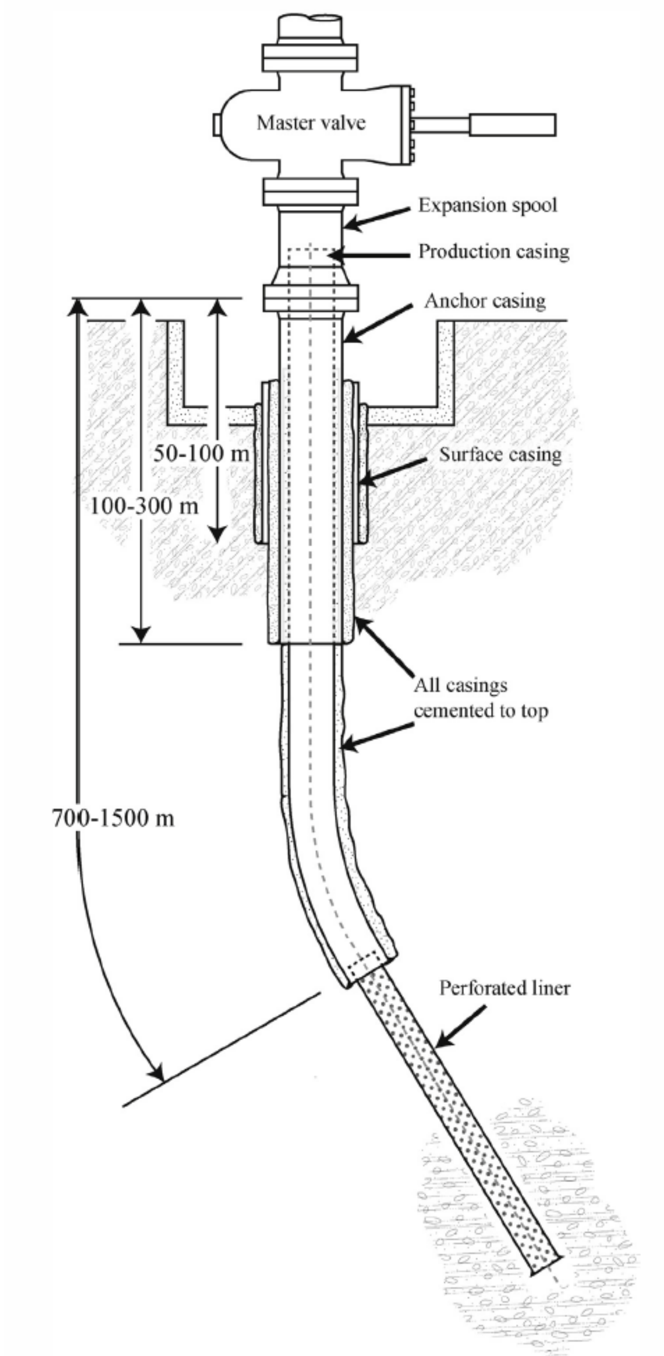


Figure 2-7 Typical well design (Kaldal et al., 2015)

Geothermal wells are dependent on high production rates, often above 100 000 kg/hr (Finger & Blankenship, 2010). To reach maximum flowrate, large diameter production casings (13 3/8”) are often preferred as they are known to produce more than normal sized wells (9 5/8”) (Þórhallsson, 2003). The production rate is proportional to the limiting factor of the casing size, assuming excellent permeability. This has been proven in Iceland where a normal sized well produced up to 80 kg/s and a large sized casing delivered up to 180 kg/s (Thorhallsson, 2008). A two-phase flow that is vapour-dominated in a large casing will reduce the pressure drop and improve productivity (Finger & Blankenship, 2010).

Guidelines, such as API and the ISO standard do not cover casing design for operating at elevated temperatures. The high temperatures in geothermal wells require special attention as the casing can be stressed beyond its yield strength (Finger & Blankenship, 2010; Torres, 2014). Geothermal wells are designed to withstand pressure loads and axial tension. In addition, thermal stresses are of high importance in geothermal well design since it can cause a significant reduction of the yield strength in the casing. Thermal stresses are often neglected in petroleum wells as the temperatures do not reach the same levels as geothermal wells. Three design criteria need to be considered to account for temperature effects on the material properties of steel in geothermal wells (Torres, 2014):

- Yield strength reduction
- Thermally induced axial stress
- Plastic deformation design (Maximum tensile load)

Due to highly corrosive environments caused by contents of CO_2, H_2S or other elements, geothermal wells require a non-standard casing (Lukawski et al., 2014). API Buttress casing connections are commonly used in geothermal wells (Ingason et al., 2015; Teodoriu & Falcone, 2009) and common casing grades are presented in Table 2-2. These casing grades are reported to be in use by different authors and has been gathered by Teodoriu and Falcone (2009):

Casing grade	**Comment**	**Author**
J-55		(Brunetti & Mezzetti, 1970; Carden, Nicholson, Pettitt, & Rowley, 1983; Chiotis & Vrellis, 1995)
K-55	Usually replaces J-55 for deep wells	(Teodoriu & Falcone, 2009)
N-80		(Brunetti & Mezzetti, 1970; Carden et al., 1983; Chiotis & Vrellis, 1995; Ragnars & Benediktsson, 1981; Witcher, 2001)
L-80	Usually replaces N-80 in the presence of H_2S	(Lazzarotto & Sabatelli, 2005)
T-95	Has replaced C-95	(Teodoriu & Falcone, 2009)
S-95	In the absence of H_2S	(Carden et al., 1983)
P-110	In the absence of H_2S	(Teodoriu & Falcone, 2009)
9 Chrome L-80	For extreme environments	(Teodoriu & Falcone, 2009)
13 Chrome L-80	For extreme environments	(Teodoriu & Falcone, 2009)
Beta-C Titanium	For severe conditions	(Pye, Holligan, Cron, & Love, 1989)

Table 2-2 Casing grades used in geothermal fields

2.3.2 Wellhead

Previously, the wellhead was connected to the casing head and production casing directly. Today, most wellheads are attached to an expansion spool that is connected to the casing head and anchor casing. This allows the production casing to expand due to axial thermal stress and let the wellhead stay in a fixed position (Kaldal et al., 2015; Þórhallsson, 2003). However, Þórhallsson (2003) states that this is not a great problem as a properly cemented casing will only expand by a couple of centimetres.

During discharge of a high temperature well, pressure fluctuations and increased temperatures may cause wellhead movement and could indicate damaged cement in annulus (Kaldal, Jónsson, Pálsson, & Karlsdóttir, 2012). Wellhead movement could also indicate a damaged casing, which could lead to a blowout. This occurred in Iceland in the 1970’s due to a leak in the casing caused by aggressive corrosion leading to an explosion creating a large crater (Kaldal et al., 2012; Pálmason, 2005).

Kaldal et al. (2015) simulated with a finite-element model (FEM) and measured wellhead movement during discharge of 5 different wells in Iceland. The model correlated well with the measured movements. The largest difference showed a rise of 5.2 cm over a period of 9 days, compared to the simulated 4.4 cm. This model could be used in future studies of structural integrity of casing under various loads.

Manufactured expansion spools contain a pressure seal which would need to be maintained pressure tight. Also, the expansion spool and casing head have valves for killing the well and for pressure testing the annulus. In Iceland however, most high temperature wells have expansion spools and casing heads with no valves below the master valve due to frequent problems with valve leaks that can be difficult to seal. The kill line is placed between the upper master valve (UMV) and the lower master valve (LMV) (Þórhallsson, 2003). In Figure 2-8 the Icelandic design of a high temperature well is shown; the wellhead is connected to the anchor (intermediate) casing and the production casing is allowed to move freely inside the expansion spool.

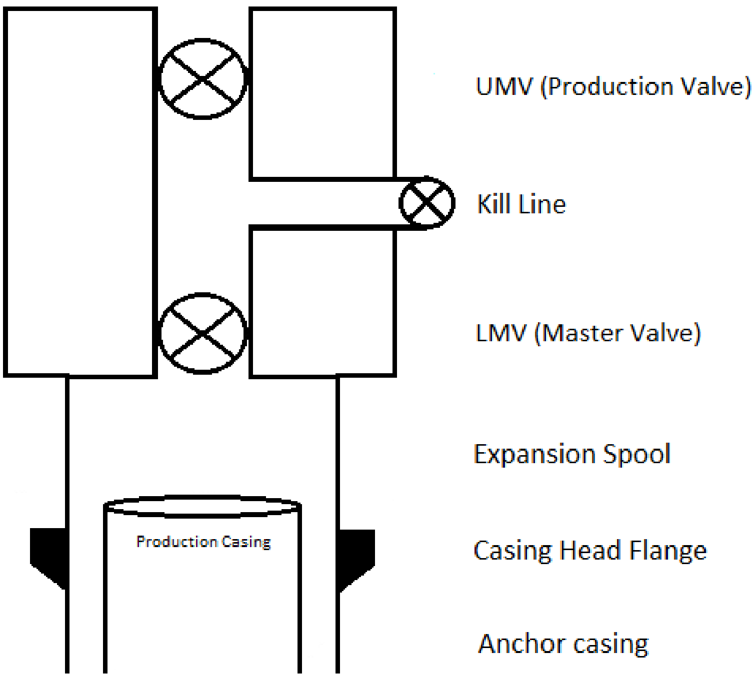


Figure 2-8 Upper part of a typical high temperature well in Iceland

2.3.3 Monitoring Geothermal Wells During Production

Many government authorities regularly require data from monitoring of produced and reinjected fluid. Interpreting physical and chemical changes that may occur creates an understanding of the reservoir behaviour, and provides the ability to detect abnormalities in the well that may require intervention. It also aids in maintaining productivity in the power plant. Some of the main monitoring measures are listed on the next page and for more details readers are referred to Þórhallsson (2003).

- Continuous measurement of wellhead pressure (bar), wellhead temperature (°C) and total flow rate (kg/s).
- Downhole measurement of temperature and pressure 1-2 times per year.
- Running caliper log intermittently.
- Sampling of chemicals at the wellhead 1-2 times per year.
- Regularly determining steam purity through samples at turbine inlet.
- Measurement of corrosion and scaling through a corrosion coupon situated at the wellhead.
- An output test performed approximately once a year, allowing the measurement of mass flow vs. wellhead pressure for several points, giving an "output-curve" and enabling calculation of the average fluid enthalpy (kJ/kg).

2.3.4 Innovations for Geothermal Wells

Innovative solutions should reduce cost without putting the well integrity at risk. The aim is to improve barrier monitoring, reduce corrosion and prevent barrier failure. Some alternatives gathered by Wood Group, Well Engineer Partners, and Baker Risk (2016) are summarized below.

Non-metallic tubing is resistant to corrosion and is very light weight compared to steel. The drawback is less resistance to wear, smaller internal diameter than that of a comparable steel tubing and the downhole connection design and integrity needs to be taken into consideration.

Installing tie-back strings and fixing them to the PBR of the lowest liner hanger creates a closed annulus between the tie-back liner and the casing. This closed annulus is easier to monitor and gives the possibility to retrieve the casing if required. It can also be used to restore the well integrity in case of a casing leak. One disadvantage of the tie-back liner is the reduction of the inner well diameter.

Coating the casing interior will protect the metal from corrosion assuming a complete coating coverage properly designed for the operating temperature. A weakness of using coating is during intervention or tubing removal where the coating will be susceptible to damage which in turn can expose the metal to localised corrosion. The lifetime exposure of the coating needs specific design as the chemical structure is affected by the high temperature.

The petroleum industry has good experience with using cemented liner casing for water injection wells. It is tougher than coated casings but has a smaller internal diameter compared to un-lined casings.

2.4 Well Integrity

NORSOK D-010:2013 (2017) is a standard developed by petroleum industry participation and owned by the Norwegian petroleum industry. It represents requirements and guidelines relating to well integrity and defines well integrity as: "Application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well".

The primary purpose of well integrity is to maintain control of fluids at all times to prevent unintended flow (D-010:2013, 2017; Vignes & Aadnøy, 2010).

NORSOK D-010:2013 (2017) sets the minimum requirements for equipment and solutions used in a well, but it is the operator's responsibility to select solutions adhering to the standard. Good operational procedures such as continuous pressure monitoring of the annulus is also required to ensure that well integrity requirements are met. Problems have occurred due to poor handover of correct information, which means that organizational solutions, communication and competent personnel are required for proper maintaining of safety (Torbergsen et al., 2012).

2.4.1 Well Barriers

The petroleum industry has engaged the philosophy of applying two well barriers since the 1920’s (Anders et al., 2015). A well barrier is a well barrier envelope consisting of one or several well barrier elements (WBE) that can withstand uncontrolled release of formation fluids (D-010:2013, 2017). Degradation or interruptions of barrier elements that causes failure in the well barriers function require immediate attention (Okstad & Sangesland, 2009). The main objectives of a well barrier is to isolate production fluids from the external environment during production or well operation, and to allow for closing in the well should an emergency situation occur (Torbergsen et al., 2012).

NORSOK D-010 (D-010:2013, 2017) defines primary well barrier as “First well barrier that prevents flow from a potential source of inflow” and secondary well barrier as “second well barrier that prevents flow from a potential source of inflow”. A simple interpretation can be explained from the drilling phase, where overbalanced drilling mud acts as a primary barrier and BOP as a secondary barrier. The primary and secondary barriers are independent of each other and the secondary barrier must be viewed as the last barrier defence, not a secondary defence in a sequence (Anders et al., 2015). A principle sketch is shown in Figure 2-9.

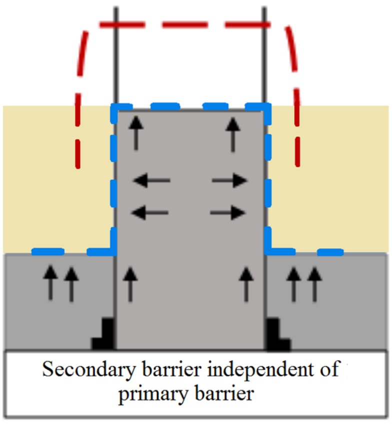


Figure 2-9 The principle of two barrier envelopes (Anders et al., 2015)

NORSOK D-010 used well barrier schematics (WBS) and formalized the well barrier standards in Norway in 2003. Defining well barriers using WBS creates a common understanding to all participants which contributes to safer well activity (Anders et al., 2015). An example of a WBS for a petroleum well is shown in Figure 2-10 depicting primary barrier (blue) and secondary barrier (red) with their well barrier elements (Okstad & Sangesland, 2009).

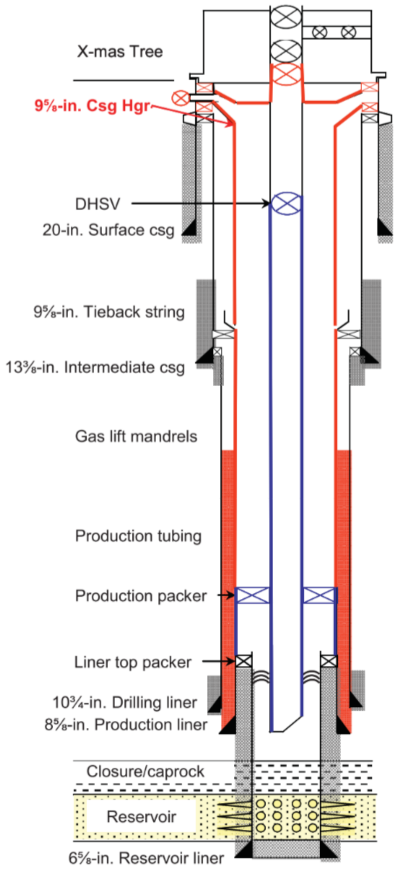


Figure 2-10 Well Barrier Schematics for a general petroleum well (Okstad & Sangesland, 2009).

NORSOK D-010:2013 (2017) requires two well barriers if hydrocarbon is present in the formation or if the pressures in the formation are high enough to cause a potential flow to surface. The well barrier shall be capable to “withstand maximum differential pressure and temperature, be verified by pressure testing or by other methods, ensure no single failure of a well barrier can lead to uncontrolled flow, re-establish a lost well barrier or establish another alternative well barrier, operate competently and withstand the environment it may be exposed to over time, monitoring of well integrity status when possible and determine the location, be independent of each other and avoid having common well barrier envelopes to the extent possible”. Once a well barrier is defined before and after installation it shall be function tested, pressure tested and monitored.

In situations where it is not possible to establish two independent well barriers, there will be a common WBE. This will require risk analysis, risk reducing measures, additional precautions and acceptance criteria when qualifying and monitoring the common WBE (D-010:2013, 2017).

According to K. Ingason (personal communication, 17. Feb 2017), there is generally no equipment installed downhole in geothermal wells and the downhole barriers are only cemented casings. The casing and cement are barriers against pollution of nearby aquifers. Should a casing leak occur, geothermal fluids could contaminate groundwater that may be a source of drinking water. Multiple casing strings are therefore installed at required depths to act as additional barriers, Þ. Sigurðsson (personal communication, April 18, 2017) (DiPippo, 2016).

Wood Group et al. (2016) investigated if the fluid column in a low temperature well, requiring pumping for production, satisfied the requirements of acting as a primary barrier for the entire well life cycle according to NORSOK D-010:2013 (2017) and ISO 16530. During drilling, they found it satisfactory to define the hydrostatic fluid as primary barrier, comparable to the guidelines definition of drilling mud as primary barrier. In the production phase they proposed that the formation water could be interpreted as pressure containment barrier. This is because in these low temperature wells, without a running pump, no water will flow to the surface.

2.5 *Risk Assessment Methods of Well Integrity Risks*

To maintain well integrity there needs to be an understanding of potential issues that may cause uncontrolled release of formation fluids (Dethlefs & Chastain, 2012). NORSOK D-010:2013 (2017) requires a risk assessment of well integrity risks to be performed for the planned activity. Failure modes of primary well barrier elements and the availability of secondary well barrier have to be considered. In the event of barrier degradation, the risk assessment should consider:

- Cause of degradation
- Potential of escalation
- Reliability and failure modes of primary well barrier elements
- Availability and reliability of secondary well barrier elements
- Outline plan to restore or replace degraded well barrier

The qualitative well integrity risk analysis model developed by Dethlefs and Chastain (2012) identifies and ranks the risk of failure of well barriers in a well so that high areas of risk can be monitored or reduced properly. A qualitative model allows risk assessment without industry data records available and the risk analysis therefore requires industry experience and knowledge from participants with different backgrounds.

NORSOK (D-010:2013, 2017) defines risk as the “combination of the probability of occurrence of harm and the severity of that harm”, and can be presented as the combination of likelihood, consequence and knowledge as (Aven, 2017):

$$Risk: Likelihood\ X\ Consequence\ Severity\ X\ Knowledge$$

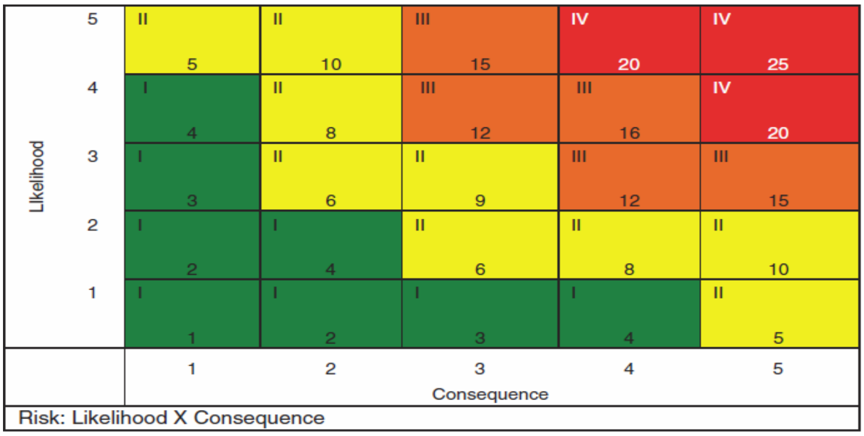
A qualitative risk assessment can be performed using many types of tools. Implementing a risk matrix to identified hazards allows for qualitatively interpreting the risk profile and level of risk based on likelihood and consequence. Also, the acceptability of the risk level will be indicated (Bower-white, 2012; Dethlefs & Chastain, 2012). Table 2-3 and 2-4 explain the defined likelihood and consequences, while Figure 2-11 shows the risk matrix and categories (Dethlefs & Chastain, 2012).

Category	**Description**
5	Severe
4	Significant
3	Moderate
2	Minor
1	Negligible

Table 2-3 Description of consequence severity

Category	Frequency	Quantitative range/Yr	Description
5	Frequent	>0.1	Likely to occur several times a year
4	Probable	0.001-0.1	Expected to occur at least once in 10 years
3	Rare	0.0001-0.001	Occurrence considered rare
2	Remote	0.000001-0.00001	Not expected nor anticipated to occur
1	Improbable	<0.000001	Virtually improbable and unrealistic

Table 2-4 Description of likelihood



IV 17–25	High	**High Risk.** Manage risk utilizing prevention and/or mitigation *with highest priority*. Promote issue to appropriate management level with commensurate risk assessment detail.
III 12–16	Significant	**Significant Risk.** Manage risk utilizing prevention and/or mitigation *with priority*. Promote issue to appropriate management level with commensurate risk assessment detail.
II 5–10	Medium	**Medium Risk With Controls Verified.** No mitigation required where controls can be verified as functional. ALARP should be evaluated, as necessary.
I 1–4	Low	**Low Risk.** No mitigation required.

Figure 2-11 Risk matrix and risk categories (Dethlefs & Chastain, 2012).

A bow-tie diagram illustrated in Figure 2-12 is a risk management tool demonstrating the risks involved. The causal factors are gathered on the left, including preventative measures, while mitigating action and potential consequences are located on the right (Bower-white, 2012; Utvik & Jahre-Nilsen, 2016).

Figure 2-12 Example of a bow-tie diagram (Utvik & Jahre-Nilsen, 2016).

Okstad and Sangesland (2009) presented a 3-step method for visualizing well integrity issues where the focus is on the operational status of well barriers before and after a well integrity problem would occur. The three steps include:

1. Use influence diagrams to "map the initial loads imposed through the previous and planned operational phases of the well".
2. Create a WBS and indicate the status of WBEs before and after the incident.
3. Prepare a barrier diagram with leak paths showing the status of each barrier element after the well incident.

The influence diagram method visualizes relationships between different influence factors and the possible effect on a final value or decision variable. A barrier diagram is presented in Figure 2-13 and points out the potential leakage paths from the reservoir to the environment. The symbolic colour scheme are the same as in a WBS and the example well barrier failure is presented by a grey colour scheme (Okstad & Sangesland, 2009).

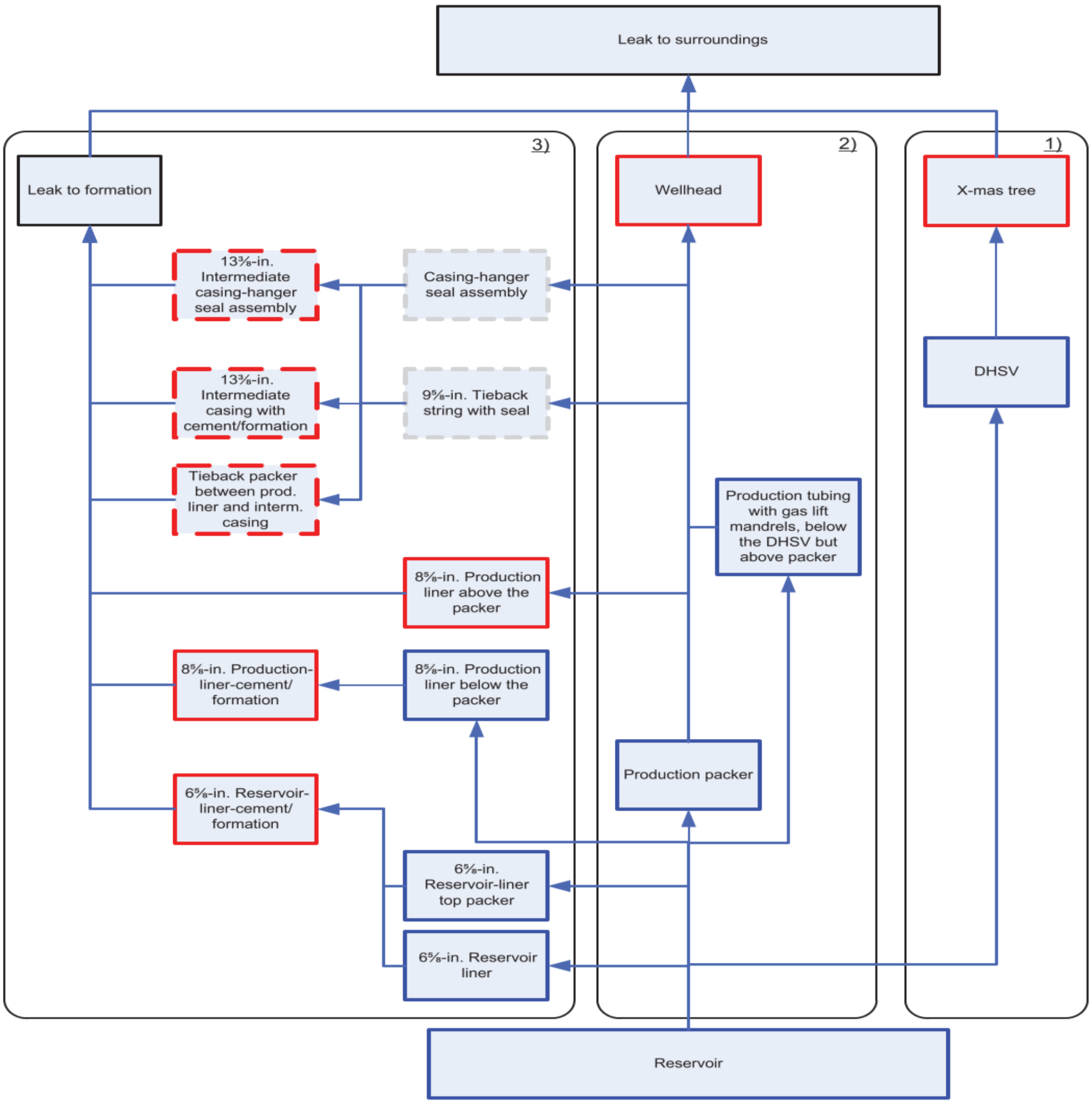


Figure 2-13 Example of a barrier diagram of a petroleum well indicating a failure in the casing-hanger (Okstad & Sangesland, 2009).

2.6 ***Well Integrity Issues in Geothermal Wells***

In geothermal wells there are problems to consider which may be unfamiliar to conventional petroleum well operators. One common challenge is complete cementation of the casing string (Snyder, 1979). High temperature and corrosion are the most common attributions to failure in geothermal wells (Southon, 2005). The casing and connections are often pushed to their technical limit. As the production is transported through the casing, the casing is susceptible to corrosion, thermal loads and fatigue. The industry design standards assume the casing string to be under a fixed load, while it can be exposed to variable loads in geothermal operations such as temperature changes or internal pressure (Teodoriu, 2015).

There are many possible causes for casing failure which Snyder (1979) summarized as “formation loading, mechanical damage, corrosion and scaling, thermal stress, metal failure and entrapped fluid expansion”. Some of the complications that may lead to failure of the production casing are explained below.

- *Thermal cycling:* During production of high temperature fluids, maintenance of the well will cause thermal cycling due to the injection of cold water when killing the well. This will cause major axial stress on cemented casings, as the casings are not able to expand and will result in plastic deformation (Torres, 2014).
- *Thermal expansion in annulus*: Fluid trapped between two casing strings may cause the casing to collapse due to high pressures from the thermal expansion of the fluid (Southon, 2005). Fluids may be trapped due to poor displacement of the drilling fluid, or during cement thickening time, where water can separate from the cement mixture due to gravity settling effects (Lentsch, Dorsch, Sonnleitner, & Schubert, 2015).
- *Corrosion*: Reduction of the casing wall thickness due to corrosion may lead to buckling of the casing or casing leak (Snyder, 1979; Southon, 2005; Teodoriu, 2015).

S. Þórhallsson (personal communication, 2017) describes long term well operations at formation temperatures above approximately 300°C as problematic. The wellhead pressure can exceed 80 bars and the casing cannot handle the thermal expansion, especially not quenching with cold water. Also, the high temperature fluids can be corrosive and contain minerals which lead to challenges with the fluid chemistry, well construction materials and thermal stresses.

2.6.1 Corrosion

Corrosion can be defined as a reaction where a material returns to its natural thermodynamic state. Corrosive processes may be significantly influenced by increasing temperatures (Schweitzer, 1996). The process of corrosion is illustrated in Figure 2-14 and consists of an oxidation reaction creating metal ions and electrons, and the electrons are consumed in the reduction reaction. The influence of the corrosive environment decides the material design (Kristanto, Kusumo, & Abdassah, 2005).

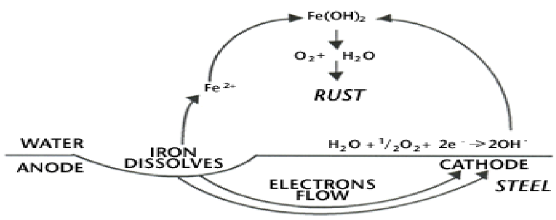


Figure 2-14 Electrochemical reaction (Kristanto et al., 2005).

Both petroleum and geothermal wells can produce corrosive fluids such as H_2S in high temperature environments (Shadravan & Shine, 2015). Metallic and non-metallic materials in the well such as casing, wellhead and cement are exposed to detrimental environments and require operators to take precautions (Shadravan & Shine, 2015). Corrosion can occur both internally and externally of the casing, and the latter is primarily due to cement deterioration which leaves the casing unprotected (Snyder, 1979).

Metallic resistance against corrosion aggression varies depending on material properties. Quantifying corrosion rates for each case using a commonly used unit, mils per year (mpy), provides a practical indication of deterioration rate. Fontana (1986) generated the relationship between corrosion rate and the resistance quality of a material as shown in table 2-5 (Shadravan & Shine, 2015).

Resistance	**Rate**	
	(mpy)	(mm/year)
Outstanding	<1	<0.025
Excellent	1-5	0.025-0.1
Good	5-20	0.1-0.5
Fair	20-50	0.5-1.27
Poor	50-200	1.27-5.08
Unacceptable	200+	5.08+

Table 2-5 Corrosion resistance and rate

The decrease in the casing thickness may be determined by measuring the amount of iron emerging from the production well. This would require knowledge of the iron content in the reservoir fluid, and the amount of scale deposited on the casing wall. The fluid data is gathered at the wellhead and well bottom treatment tubes, or from a downhole sampler, and allows for the calculation of corrosion rate (Ignatiadis & Akar, 1996).

A leak in the casing may give severe and costly impact and is often caused by corrosion, bad welding, bad cementing of the casing, thermal cycling, wear from drill pipes or erosion. A leak in the upper part of the well could lead production steam and fluid into the annulus between two casing strings. If not handled in a short enough amount of time, a leakage path to surface could in extreme cases cause a dangerous steam eruption, throwing mud and rocks and leave a large crater (Þórhallsson, 2003).

Detecting the location of a possible casing leak can be done using a caliper log, temperature log or a borehole video inspection once the well has been quenched. Caliper surveys are run intermittently to detect scaling, casing damage or corrosion. Constant collar locator can detect corroded areas and holes while a mechanical multi-finger tool run on a wireline will provide a more definite investigation. Temperature and pressure surveys downhole are performed 1-2 times a year. A temperature log will show a spike in the log at the casing hole due to temperature changes caused by flow in or out of the hole. Once a hole has been created, erosion from production steam or fluid could enlarge the hole (Þórhallsson, 2003).

Pressure and temperature determine the phase of the fluids. In liquid phase the dissolved minerals, silica and salts mostly occur. Gases such as carbon dioxide are dissolved in the liquid phase until the boiling point where they quickly will transfer to the vapour phase (Thorhallsson, 2005). Corrosion problems occur frequently in equipment due to the highly corrosive geothermal steam and brine. Ocampo-Díaz et al. (2005) listed the factors involved contributing to corrosion attack:

- Carbon Dioxide, CO_2
- Hydrogen Sulfide, H_2S
- Hydrogen Chloride, HCl
- Iron Sulfide, FeS
- Sulfuric Acid, H_2SO_4
- Oxygen, O_2
- Temperature
- Suspended Solids
- Flow Hydrodynamics

2.6.1.1 Uniform Corrosion

The even removal of metal which results in a relatively uniform thickness reduction across the surface exposed to a corrosive environment, is known as uniform, or general, corrosion (Schweitzer, 1996). The uniform removal from the surface forms the basis of most corrosion prediction equations. Measurement, or rate of corrosion over an even surface area, is often given as weight loss and is considered as uniform corrosion (Kristanto et al., 2005). The principle of uniform corrosion is illustrated in Figure 2-15.

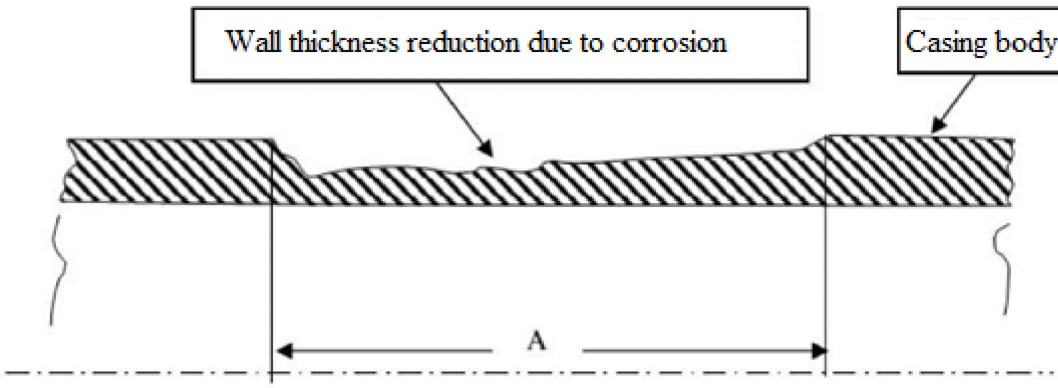


Figure 2-15 Uniform corrosion (Teodoriu, 2015).

2.6.1.2 Pitting Corrosion

This type of corrosion will eventually create localized holes in the metal surface. Metallic elements such as iron, Fe, will oxidize and react with halides (Shadravan & Shine, 2015). Stainless steels are susceptible to pitting corrosion in environments containing halides such as chloride. Pitting may cause leakage problems and also reduce the fatigue life of the metal due to stress concentrations. Despite all precautions taken regarding the corrosive environment, pitting corrosion may cause unexpected material failure (Pohjanne, Carpen, Hakkarainen, & Kinnunen, 2008).

2.6.1.3 Erosion Corrosion

This corrosion mode can accelerate the rate of corrosion attack due to fluid flow in the wellbore. Erosion mechanically removes the passive layers protecting the casing wall, and this may cause more aggressive chemical corrosion. Erosion corrosion typically occurs under high flow rates and increases in presence of solid materials and bubbles in the flow, causing wear on the internal surface (Kristanto et al., 2005; Shadravan & Shine, 2015).

2.6.1.4 CO_2 Corrosion

CO_2 is the most common corrosive element in geothermal wells and is present in almost all wells. CO_2 corrosion can attack both metallic and non-metallic parts of the well. One of the causes of metal corrosion is the carbonic acid formed by carbon dioxide in steam and water (Shadravan & Shine, 2015). The aggressiveness of CO_2 corrosion to the metal depends on temperature, material characteristics, CO_2 partial pressure and various other factors (Ueda & Takabe, 2001). CO_2 corrosion can be the cause of both uniform and localized corrosion (Lopez, Perez, & Simison, 2003). A common corrosion product in a CO_2 environment is iron carbonate, $FeCO_3$, which will precipitate on the metallic surface. The total reaction is given as (Shadravan & Shine, 2015):

$$CO_2 + H_2O + Fe \rightarrow FeCO_3 + H_2$$

2.6.1.5 Stress Corrosion Cracking

There are three contributing causes to stress corrosion cracking; the environment, stress and material properties. All three must be present to allow the formation of cracking as illustrated in Figure 2-16. The environment may contain factors such as H_2S, CO_2 and high temperature and pH that can stimulate crack growth. A large stress level can cause cracking on a material with properties below the required strength. To prevent stress corrosion cracking, any of these contributing causes needs to be eliminated or improved (Hodson-Clarke et al., 2016).

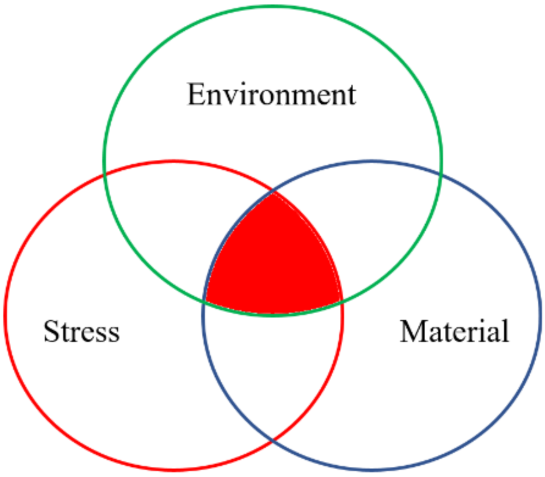


Figure 2-16 The contributing factors to stress corrosion cracking (Hodson-Clarke et al., 2016)

2.6.2 Scaling

Geothermal steam and fluid could contain elements such as calcium, silica and sulphide which can precipitate from the brine and deposit onto the casing wall. This phenomenon is known as scaling and occurs due to changes in pressure, temperature or pH. Scaling is a considerable challenge in many geothermal wells and can cause plugging of the well, require repair or replacement of equipment, and reduce well flow and power production (Karlsdottir, Ragnarsdottir, Moller, Thorbjornsson, & Einarsson, 2014; Ocampo-Díaz et al., 2005; Thorhallsson, 2005). However, the scaling itself could protect the metal surface from direct contact with corrosive production fluids (Snyder, 1979).

The location of scaling deposition can be controlled by regulating the wellhead pressure. The wellhead pressure is related to the pressure at a certain depth and can be regulated by opening the control valve, allowing control of scaling deposition from about 50 meters up or down in the well (Viveiros Pereira, 2015). S. Þórhallson (personal communication, February 16, 2017) noted that deposition of scaling causes declination in only a small number of wells in Iceland, and they are reamed once a year for flow recovery. On the other hand, prolonged high production levels may change the impact. The temperature ranges of scaling depositions are:

- Calcite scaling 180-240°C
- Silica scaling 240-290°C
- Silica and sulphide scaling >290°C

A different form of scaling is caused by formation of corrosion products such as $FeCO_3$ from CO_2 corrosion on the surface area of the metal. Corrosion scale could form a protective layer against further corrosion. However, this form of scaling may also be connected to degradation of the metal (Mundhenk et al., 2013; Palacios & Shadley, 1991; Shadravan & Shine, 2015).

Mundhenk et al. (2013) conducted an experimental research for understanding corrosion and scaling in a geothermal plant. The in-situ and laboratory experiments showed a substantial connection between corrosion and scaling. Mild steels such as API N80 and P110 were exposed to temperatures from 20°C to 80°C and from 1 week to 5 months. Corrosion scale occurred in both experiments and acted as a protector, reducing the corrosion aggression.

2.6.3 Mitigating Corrosion

There are several measures available to mitigate corrosion problems:

- Maintaining pH above 5 in carbon steel parts of geothermal wells may be the primary corrosion mitigation required (DiPippo, 2016).
- Choosing high alloy steel (Gallup, 2009).
- Inhibitors (Gallup, 2009; Ignatiadis & Akar, 1996)
- Control dew point depth by pressure control, depending on vapour or liquid as the most aggressive corrosion factor, Þ. Sigurðsson (personal communication, April 18, 2017).
- Determining location of scaling deposition with the aim to generate a protective uniform layer, Þ. Sigurðsson (personal communication, April 18, 2017).
- Ensure proper cementing (Won, Choi, Lee, & Choi, 2016).
- Keeping the well hot, Þ. Sigurðsson (personal communication, April 18, 2017) (Southon, 2005).
- Increase casing wall thickness (Hodson-Clarke et al., 2016).

2.6.4 Cementing of Geothermal Wells

Isolation is the main aim of the cement job in oil and gas wells (DiPippo, 2016). In contrast, the main purpose of cementing in geothermal wells is to reduce the elongation of the casing caused by temperature change in all phases of development, from placement to production. Also, it reduces thermal fatigue as a result of thermal extraction and contraction.

To date, cement barriers identified by NORSOK D-010 (D-010:2013, 2017) should have properties such as “impermeable, long term integrity, non-shrinking, ductile – (non-brittle) – able to withstand mechanical loads/impact, resistance to different chemicals/substances (H_2S, CO_2 and hydrocarbons) and wetting, to ensure bond to steel”.

According to Won et al. (2016) the completion of geothermal well cementing has three main challenges. Firstly, the strength of the cement slurry must be high enough to support the steel casing which is prone to expansion during temperature changes. Secondly, the cement slurry needs to displace the water-based drilling fluid. Thirdly, protect the casing from corrosion by a complete cement sheath (Edwards, Chilingar, Rieke Iii, & Fertl, 1982). The steel casing is mechanically supported by the surrounding cement material and this will also protect against initial corrosion and erosion caused by geothermal fluids up to 320 °C (Sugama, 2006)**.**

A considerable amount of published literature studies the effect of cementing properties in performance of geothermal wells. The following sections include numerical, experimental and analytical works done in order to evaluate geothermal well cementing.

2.6.4.1 Simulation of Cement Properties

Won et al. (2016) completed a two-dimensional (2-D) Finite Element (FE) analysis of a geothermal well with respect to five different cross-sections at various depths. The design specifications correspond for the geothermal well that is currently constructed in Pohang, South Korea. They reported that the cementing components experience less stress concentration with increasing number of casing layers. Lower thermal conductivity of the cementing material is advantageous for efficient controlling of radial displacement. It was also noted that long term strength degradation of the cement might result in severe geothermal well instability.

Won et al. (2016) reported that relatively low thermal conductivity (0.62–0.68 W/mK) might be suitable for geothermal wells to prevent heat loss in the production well, but may still induce more concentration of tangential stress at the inner most casing based on the FE analysis. However, the low thermal conductivity of the cementing is effective in decreasing the well expansion.

Won et al. (2016) showed that an increase in the Young’s modulus of the cementing component would also increase the tangential and radial stress exerted in the geothermal well. Whereas, the variation of stress and displacement along with the Young’s modulus decreases as the depth of the geothermal well increases.

2.6.4.2 Petro Physical Characteristic (Experiments)

Krilov, Loncaric, and Miksa (2000) investigated a petroleum well production failure where the well had been producing for 15 years prior to the failure. Through laboratory experiments they simulated the downhole conditions and discovered the main cause of the failure. Cement exposed to a CO_2 rich environment in high temperature wells (>180°C) will lose its compressive strength and structural integrity of the cement sheath over time. The high temperatures raise the aggressiveness of CO_2 reaction, increasing the porosity and permeability of the cement matrix, exposing the casing and leading to loss of zonal isolation.

Kosinowski and Teodoriu (2012) observed through experiments that the cement sheath protecting the casing may fail due to thermal cyclic loads. The cyclic loads expose any material to fatigue and repeated exposure may lead to failure. The casing expands due to thermal stress creating cracks in the cement as shown in Figure 2-17. The bond between the casing and cement might be lost, allowing corrosive fluids to attack the external casing wall.

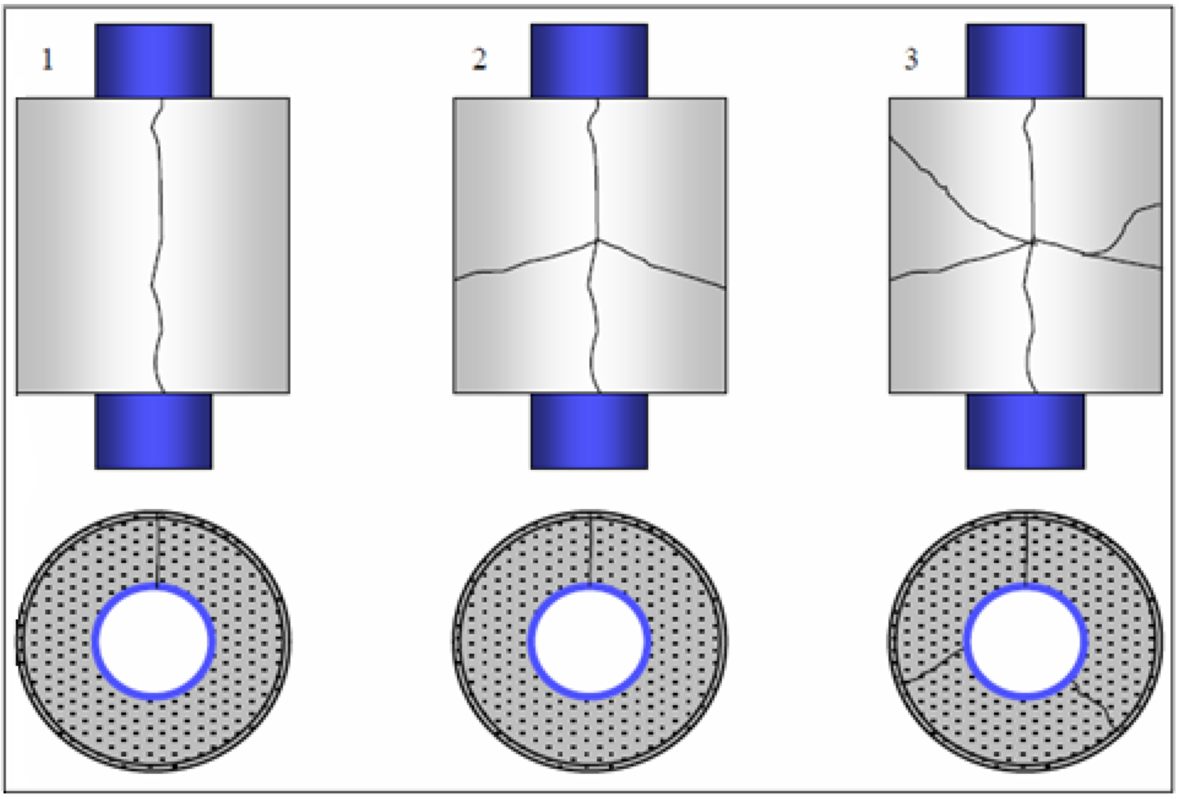


Figure 2-17 Failure of cement during testing (Kosinowski & Teodoriu, 2012).

2.6.4.3 Optimizations and Scaling

Achieving a proper cement displacement requires optimization prior and during cementing. Focusing on best practises would reduce the risk of trapped fluid in cement and thermal expansion in the annulus, as well as creating a good bonding of the cement. Lentsch et al. (2015) pointed out some cementing best practices that previously were not commonly conducted due to financial purposes.

- Prolonged mud circulation time to achieve the desired mud properties and a qualified borehole
- Pump minimum 20% extra volumes of cement during liner cementation. For cementing a surface casing with a stinger, it is recommended to wait for full density cement to reach the surface before the displacement cement is pumped down.
- Alternating flow rates to improve the transport of gelled mud and cuttings. This should only be done in formations that can handle the high-pressure fluctuations.
- Create a better cementation at casing-to-casing overlaps by installing and cementing tiebacks.

2.7 *Field Case Study*

This chapter consists of the study of geothermal wells dealing with corrosive environments. An overview of the investigated wells is listed in Table 2-6.

Well	Location	Main issues	Temperature (°C)
IDDP-1	Krafla, Iceland	Thermal cycling, corrosion of the liner, WH valve failure	450
Habanero 3	Cooper Basin, Australia	Corrosion in the upper part of the well	280
Several wells	Cerro Prieto, Mexico	Internal and external corrosion of the production casing	320
Several wells	Salton Sea, USA	Uniform and pitting corrosion of the production casing	232-315

Table 2-6 Overview of geothermal wells indicating corrosion issues

2.7.1 Icelandic Deep Drilling Project, IDDP

The research project Iceland Deep Drilling Project (IDDP) is examining the possibility of producing high energy supercritical geothermal fluid to achieve an increased power output. The first well attempting to reach depths down to 4-5 km was IDDP-1 at Krafla in Iceland, 2008-2009. The well produced over a period of two years and was the hottest geothermal well in the world reaching temperatures of 450°C at the wellhead and pressures between 40 and 140 bar (G. Friðleifsson et al., 2015).

The drilling of the vertical production well progressed down to 2,1 km where it encountered magma at temperatures in excess of 900°C. The drill string was successfully pulled out and two casings were set at 1950 m depth; a 13 5/8” production casing and a 9 5/8” sacrificial casing cemented inside the production casing, instead of a cement plug in the bottom of the hole. From there a 9 5/8” slotted liner went down to 2072 m depth as shown in Figure 2-18. In 2012 the wellhead suffered from failure of both master valves resulting in a relatively quick shut in of the well (G. Friðleifsson et al., 2015; Ingason et al., 2015).

The experience from IDDP-1 was implemented in the well design process of IDDP-2. The upper parts of the casing design from IDDP-1 was acceptable for IDDP-2. However, corrosion debris found at the wellhead originating from the liner, gave reason to reconsider the liner design. The sacrificial production casing failed due to thermal cycling as was anticipated. Measures to reduce the risk of casing failure from quenching the well could be by injecting hot fluid when killing the well, or to minimize the need for shut in by modifying the wellhead (Ingason et al., 2015).

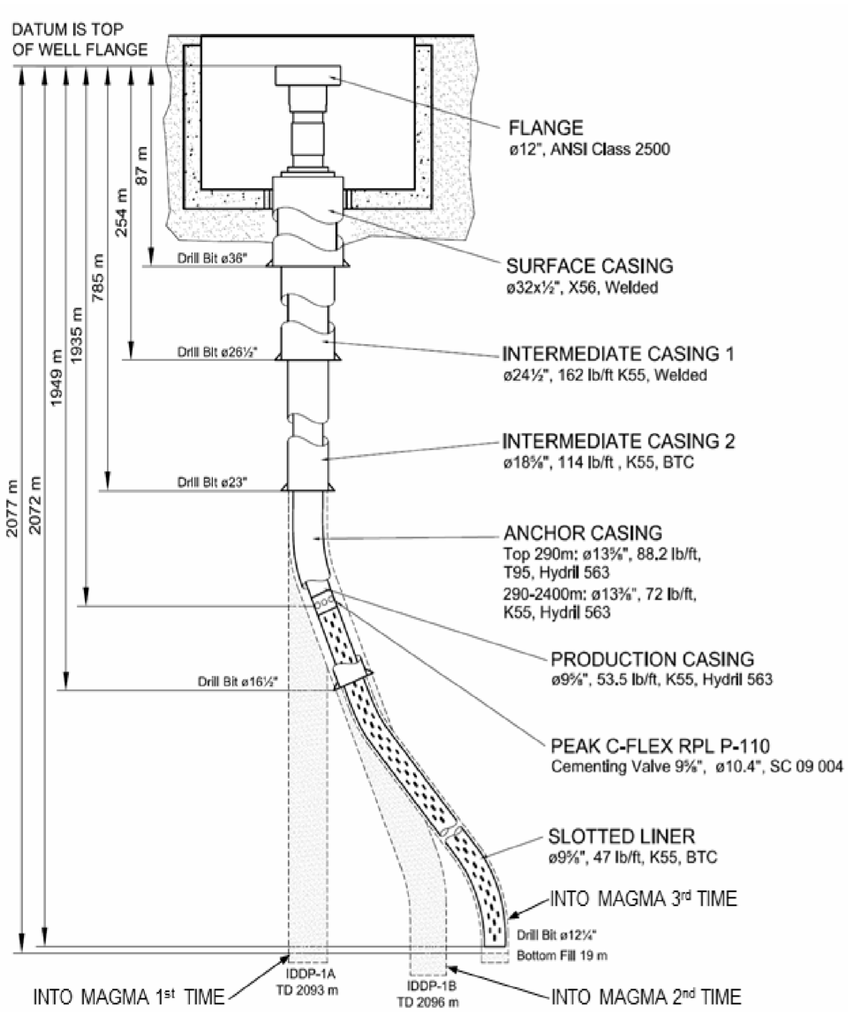


Figure 2-18 Sketch of well IDDP-1 as built (G. Friðleifsson et al., 2015)

2.7.2 Cooper Basin

The Habanero wells are located in Cooper Basin in South Australia. The wells in the area are drilled deeper than 4 km and the high temperatures (280°C) and pressures make the area challenging for well construction (Hodson-Clarke et al., 2016). As mentioned by S. Þórhallson (personal communication, February 18, 2017), these wells are not conventional geothermal wells as they are drilled into geopressured reservoirs. This pressure level is not seen in conventional highly fractured reservoirs.

The first well, Habanero 1, was drilled in 2003 and the production well, Habanero 3, was drilled in 2007 creating a closed loop EGS. As the Habanero 3 well failed two years later, measures were taken to determine the failure mechanisms. This was valuable information for the replacement well, Habanero 4 (Hodson-Clarke et al., 2016). Habanero 3 failed in the upper part of the 9 5/8” production casing. Later, the two outer casings failed and a release of production fluid occurred at surface. The failure mechanism of the production casing was determined to be a result of corrosion from high temperature and pH in the annulus. Other factors included thermal cycling, slip marks on the exterior of the casing and cyclic loads from the reservoir pressure. The failure of the production casing caused cracks in the 13 3/8” casing which lead to a pressure increase in the annulus to the 18 5/8” casing. This resulted in burst of the outer casing and loss of containment (Hodson-Clarke et al., 2016).

Thermal and pressure fluctuations and the harsh environment conditions, including temperature and fluids exposing the tubulars, were amongst the main contributors to the well design and material selection of Habanero 4. The selected grade of the production casing was TN110SS (sour service 110 ksi) with increased wall thickness. As the well was constructed under South Australian Petroleum regulations, the well was completed with a production tubing and packer, unlike conventional geothermal wells. This fulfilled the requirement of a dual barrier and at the same time eliminating the main problem from Habanero 3; pressure cycling to the production casing. In addition, creating a replacement barrier, should the corrosion aggressiveness be higher than anticipated. The schematic of the well design of Habanero 4 is in Figure 2-19 (Hodson-Clarke et al., 2016).

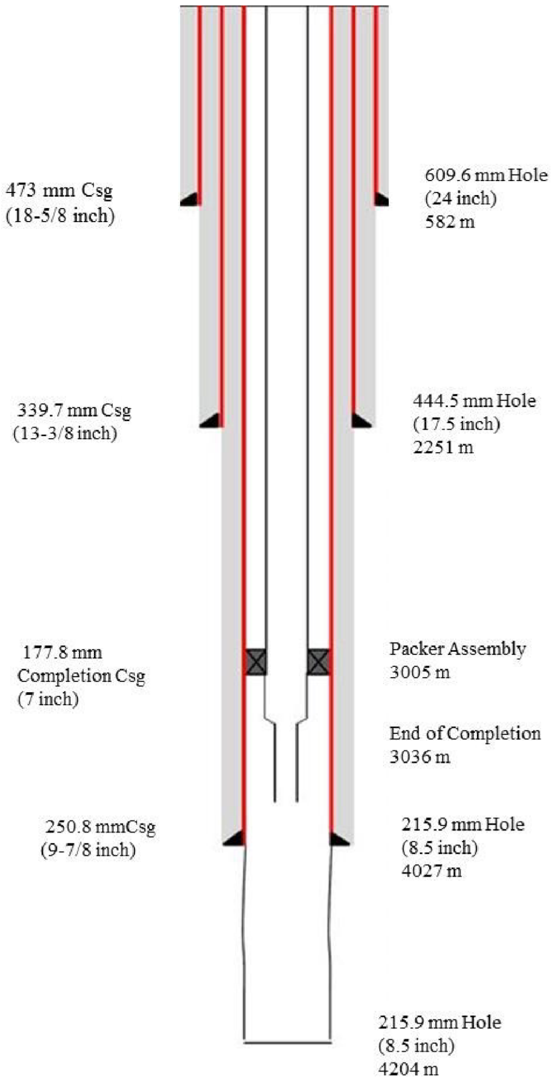


Figure 2-19 Well design of Habanero 4 (Hodson-Clarke et al., 2016).

2.7.3 Cerro Prieto

Cerro Prieto in Mexico is one of the largest geothermal fields and has been producing geothermal energy since 1973. The field consists of over 250 wells where approximately 150 are production wells with different characteristics. The most used casing grade is J-55 as it is more resistant to chemical attack. However, corrosion has damaged casing grades of both J-55 and K-55, as well as N-80. (Ocampo-Díaz et al., 2005).

Dominguez A and Sanchez G (1981) analysed the wells in Cerro Prieto after several years of production. Of 85 production, exploration and abandoned wells, corrosion problems were detected in 5 wells (Ocampo-Díaz et al., 2005). Reservoir depths in the Cerro Prieto field varied between 1300 and 3000 meters with temperatures above 320°C. The wells had corrosion issues both internally and externally, mostly attacking the production casing as shown in Figure 2-20. Significant damage was found just above the reservoir zone due to electrochemical corrosion creating external steel migration into the formation (Dominguez A & Sanchez G, 1981).

Over time, the casing grade and thickness was modified to deal with the severe corrosion issues which in some cases caused the casing to practically disappear after two and a half years (Dominguez A & Sanchez G, 1981; Ocampo-Díaz et al., 2005). Later, a number of wells were drilled and temporarily shut-in for a few months during the construction of a power plant. Some of these wells suffered from corrosion issues in the production casing as a result of static brine, air and gases in the well. Some wells required the installation of a smaller diameter casing in the interior of the damaged casing (Ocampo-Díaz et al., 2005). Ocampo-Díaz et al. (2005) concluded that various casing grades have been used to prevent or reduce corrosion problems, and that corrosion issues in pipes of production wells have been associated with high H_2S gas content.

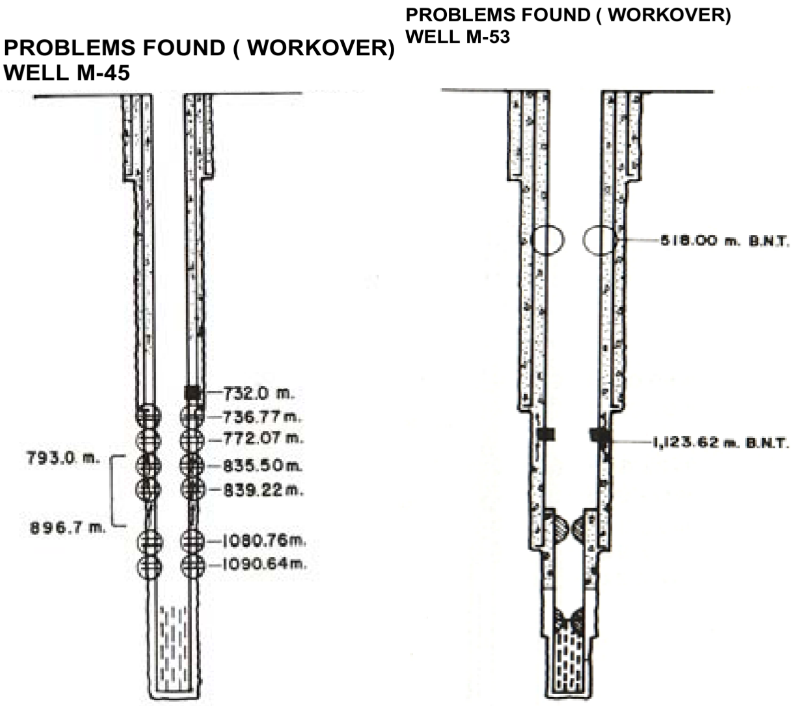


Figure 2-20 Corrosion problems in the Cerro Prieto field (Ocampo-Díaz et al., 2005).

2.7.4 Salton Sea

The Salton Sea geothermal field is located in California, USA. The natural fluids are one of the most corrosive fluids known due to the high temperatures, high salinity and H_2S and CO_2 content. The temperatures range from 232-315□ from reservoir depths between 610-1880 meters. The production casings were not cemented as most geothermal wells, which made it possible to retrieve the casing for inspection. The carbon steel production casings showed uniform and pitting corrosion at rates 1000 mils/year and some localized corrosion rates as high as 2000 mils/year at the bottom of the well. Some pitting corrosion had perforated the casing wall. This showed that inexpensive alloys could clearly not handle the corrosive environment (Pye et al., 1989).

The production casing is a major cost contributor in the corrosive environment, both using low cost carbon steel replaced at regular intervals or a corrosion resistant material cemented in place for an assumed 30 years of lifetime. Material testing showed that titanium alloys (Beta-C) did very well against corrosion attacks. None of the serviced casings had cracked even after 800 days of operation. A simplified cost analysis model showed it was the most cost effective material compared to conventional materials (Pye et al., 1989).

3 Methodology

According to Yin (2003), the gathering of data for a case study should include several sources and important informants for reviewing the report. This study includes one main interview for interpreting and describing the risks involved and also for clarifying well design and technical understanding. In addition, the case is supported by four interviews dealing with risk management, well barrier interpretation and technical understanding. Finally, valuable experience was acquired during a well integrity workshop at the University of Stavanger, arranged by the Norwegian Petroleum Society in late April 2017.

A theoretical well integrity problem for the study has been created based on an actual well design and events uncovered in interviews and reviewed literature. The main respondent received questions in advance of the interview to have the opportunity to comment on the questions and prepare for the meeting. All of the questions were performed semi-structured, with the purpose of increasing the awareness of the participants and create an informal interview process (Yin, 2003). The methodology of this thesis is presented in Figure 3-1.

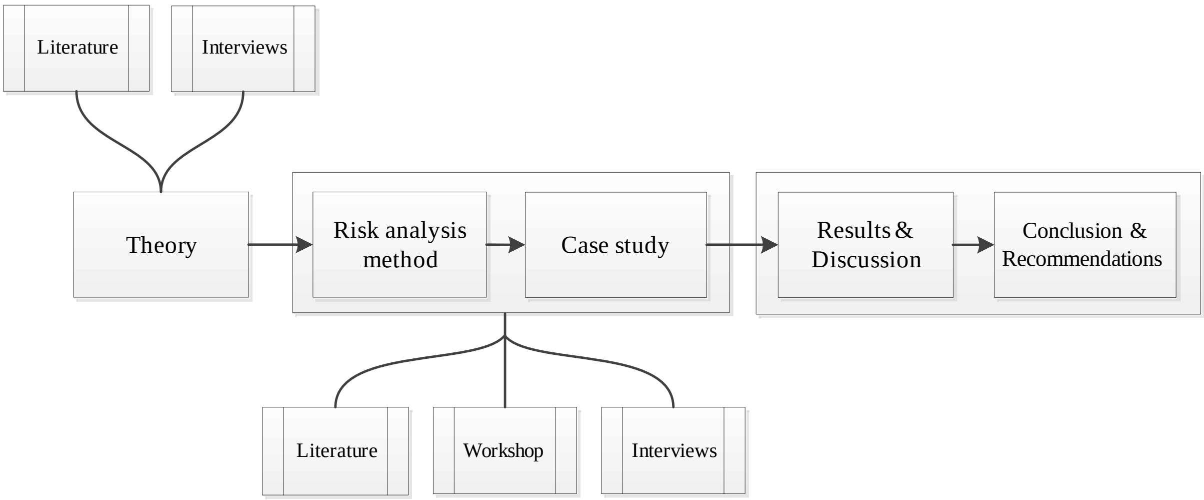


Figure 3-1 Schematic of methodology

The respondents originate from both petroleum and geothermal industries. The main respondent has experience from the geothermal industry and the other respondents include both geothermal and petroleum industries, where the latter include respondents within the fields of well barrier and well integrity. The majority of the respondents were found through published papers. Two of the respondents were contacted during and after industry courses at the University of Stavanger.

The total number of respondents and informants could generally be regarded as few, but given their background, experience and first-hand knowledge of the subject this is considered satisfactory for the selected case in this study. The validity and reliability of the information gathered needs to be critically evaluated. Some informants may be bound by confidentiality agreements and cannot disclose all information or they may provide biased information favouring themselves or their employer (Jacobsen, 2005).

3.1 *Risk Assessment Methodology*

The qualitative risk assessment methodology is developed based on published papers from the petroleum industry, supported by a well integrity workshop. The method consists of the following 4 steps elaborated below and illustrated in Figure 3-2.

1. **Identify Well Barriers -** The visualization method from Okstad and Sangesland (2009) is applied. The well barrier schematics are drawn following NORSOK D-010 with the required modifications for a geothermal well.
2. **Identify Hazards -** Secondly, a simplified influence diagram supported by a bow-tie diagram based on Utvik and Jahre-Nilsen (2016) visualizes potential hazards. These diagrams are created to help the reader increase their understanding of possible well integrity failures in a high temperature geothermal well. The identified potential hazards are then ranked in a simplified risk matrix following the assessment process suggested by Dethlefs and Chastain (2012). This is adjusted with an assumption that all mitigating actions have been performed, due to limited access to risk management information.
3. **Identify Leakage Paths -** In the case of a well integrity problem affecting the well barrier status, the following methods are applied. A barrier diagram is adapted from Okstad and Sangesland (2009) to present the possible leak paths and the status of each barrier, indicating where a possible failure mode of a well barrier is present. The well barrier status is visualized in a well barrier schematic as suggested by Okstad and Sangesland (2009).
4. **Risk Management -** The failure modes are described and explained, and the most probable cause of failure is determined. The severity of human safety, environmental impact and financial impact are established and the likelihood of the failure to actually occur is estimated. This approach is based on, but not identical to, the risk assessment model from Dethlefs and Chastain (2012). Furthermore, a mitigation plan should be outlined to assess the failure and to reflect on measures that could have prevented the failure (D-010:2013, 2017).

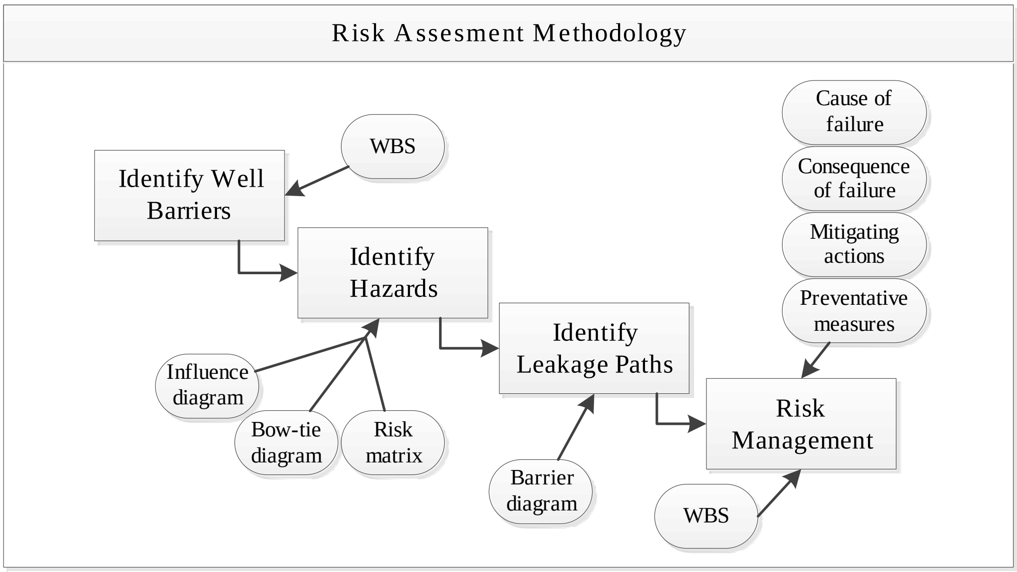


Figure 3-2 Schematic of the risk assessment methodology used in this thesis.

3.2 *Theoretical Case of Geothermal Well Integrity Problem*

The purpose of the case study is to analyse potential failures and the associated risks in a distinct geothermal well using risk assessment method composed in this thesis. The theoretical well is designed as an Icelandic high temperature well. The design parameters are based on well KG-26, located in the Krafla region in Iceland, with additional assumptions (G. Ó. Fridleifsson, Ármannsson, & Mortensen, 2006). The well is assumed to have a well integrity problem which manifests itself as a corrosion problem causing a hole in the casing fifty meters above the casing shoe.

3.2.1 Design Parameters

A well schematic is presented in Figure 3-3 on the next page. The well is assumed to be vertical down to 2000 m depth. The K-55 9 5/8” production casing shoe is set at 1200 m in coarse grained basalt. Assuming a reservoir temperature of 320°C at 2000 m depth, gives an average temperature gradient of 155°C/km, assuming a surface temperature of 10°C. The production is assumed to be vapour dominated and contains non-condensable gases such as H_2S and CO_2.

The K-55 13 3/8” intermediate casing acts as anchor casing and the casing shoe is set at 400 meters, following the “rule of thumb” from NZS 2403:2015 (2015), stating that the depth shall be 1/3 of the next section of the well. As the anchor casing has the casing head flange and is connected to an expansion spool, the production casing inside will be able to expand due to thermal stress (Þórhallsson, 2003). A 7” liner is assumed not to be necessary as it would be placed at TD and not connected to the production casing, meaning the annulus would be open, Mannvit (personal communication, April 18, 2017).

A nearby aquifer above 400 m is protected by a double barrier, meaning two casing strings and cement. The overburden formation is assumed to consist of impermeable basalt and a verified seal.

The kill line is located between the upper master valve (UMV), also known as the production valve, and the lower master valve (LMV), also known as the master valve. This is according to Icelandic procedures, as opposed to the NZS 2403:2015 (2015) standard that requires the kill line to be located below the LMV. Placing the kill line above the LMV allows for closing the LMV and repairing the kill line should a failure occur, Mannvit (personal communication, April 18, 2017).

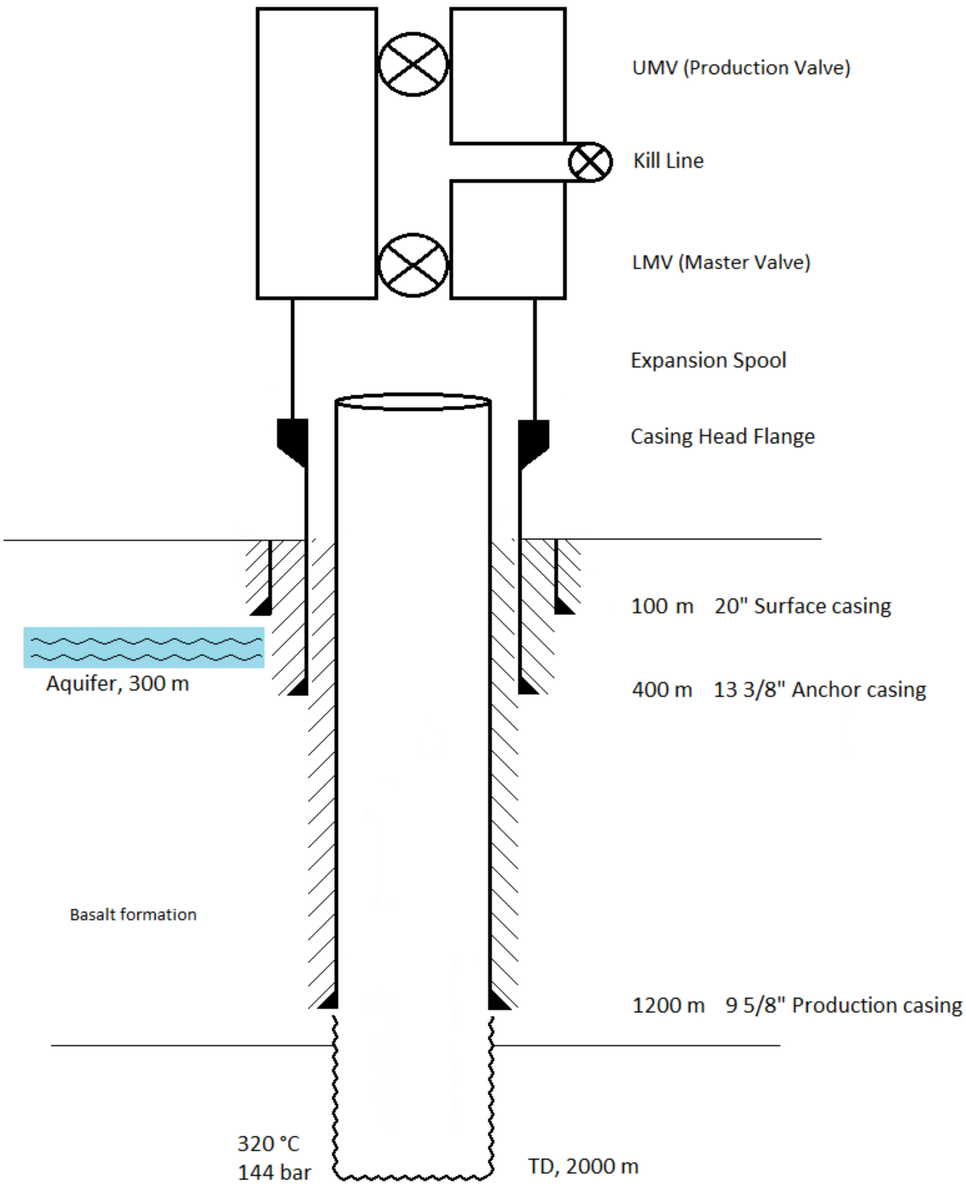


Figure 3-3 Well schematics (not to scale)

4 Risk Assessment

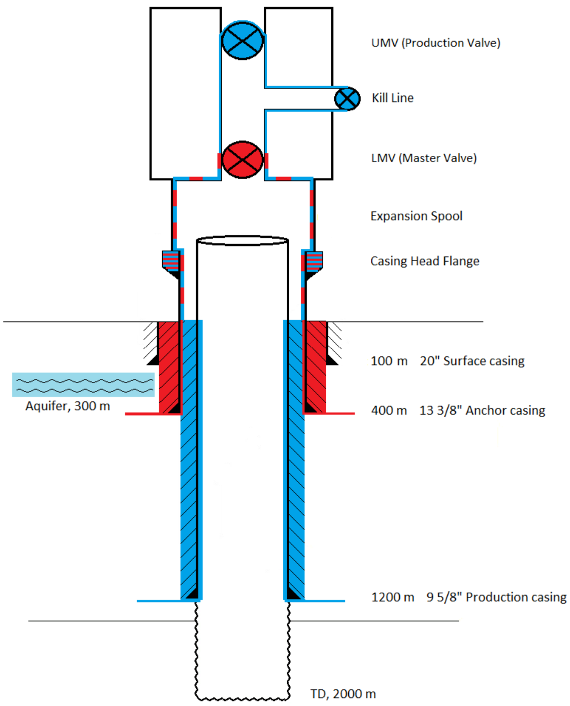
This chapter consists of a qualitative risk assessment of the example case, following the methodology described in Chapter 3. A selection of known well integrity issues for a production well in the production phase is analysed and a hypothetical corrosion problem is assessed.

4.1 *Identifying Well Barriers*

Dethlefs and Chastain (2012) suggest that an evaluation of the available well barriers should be carried out in a risk assessment to determine the likelihood and consequence of potential barrier failure modes. The well barriers defined for this theoretical well are presented in Figure 4-1. These were interpreted through discussions with Mannvit (personal communication, April 18, 2017) and supported by T. Fjågesund (personal communication, April 29, 2017).

As NORSOK D-010:2013 (2017) provides guidelines for drilling and well activities, it should be applicable for these kinds of wells as it is not limited to oil and gas wells, T. Fjågesund (personal communication, April 29, 2017). Defining the primary well barrier should include components in direct contact with formation fluids and pressure.

The secondary well barrier should ideally reside outside the primary well barrier, and not act as a secondary defence in a sequence (Anders et al., 2015). In some situations, this is not possible and a common barrier between the primary and the secondary barrier is required, T. Fjågesund (personal communication, April 29, 2017). A well barrier consists of all elements that can act as barriers. Both the upper and lower master valve could be interpreted as primary barrier, or as common barrier element, depending on the operator's definition, T. Fjågesund (personal communication, April 29, 2017). The upper master valve is controlled hydraulically and therefore considered a primary barrier, Mannvit (personal communication, April 18, 2017).



Well barrier elements
Primary barrier
In-situ formation
Casing cement
Production casing
Casing head flange
Expansion spool
Wellhead
Kill line
UMV (Production Valve)
Secondary barrier
In-situ formation
Casing cement
Anchor cement
Casing head flange
Expansion spool
Wellhead
LMV (Master Valve)

Figure 4-1 Well barrier schematics (WBS), not to scale.

4.2 *Identifying Hazards*

Some of the main potential causes of casing failure during production considered in this case study, are summarized as (Snyder, 1979; Southon, 2005; Summers et al., 1980), Mannvit (personal communication, April 18, 2017):

- Mechanical damage during well development
- Corrosion from geothermal fluids
- Thermal stress
- Expansion of entrapped fluids in annulus

During drilling or workover situations, the casing wall and wellhead valves are in risk of damage by the equipment (Snyder, 1979). The corrosive geothermal fluids could reduce the casing wall thickness, cause a casing leak or attack the wellhead (Southon, 2005). The temperature changes during quenching and discharge of the well might cause a thermal shock on the casing, resulting in plastic deformation and potentially exceeding the yield limit of the casing. Under the initial start-up of the well, entrapped fluids in the cement between two casing strings can expand and cause the casing to collapse (Southon, 2005). The potential hazards and their effects are illustrated in a simplified influence diagram in Figure 4-2.

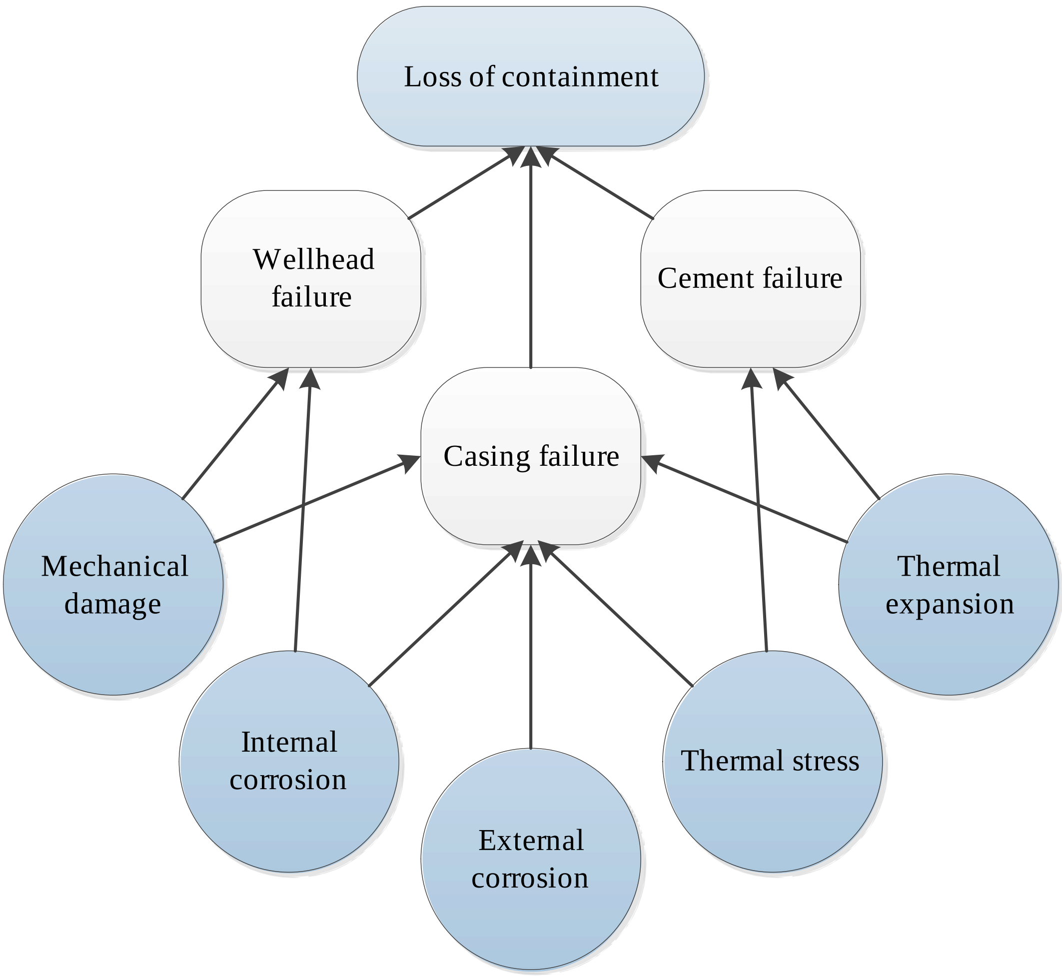


Figure 4-2 Simplified influence diagram of potential hazards in a geothermal well

Figure 4-3 represents a bow-tie diagram identifying hazards with the top event being a casing failure. The bow-tie diagram visualizes how the risks of potential hazards are controlled and the possible responses to an event.

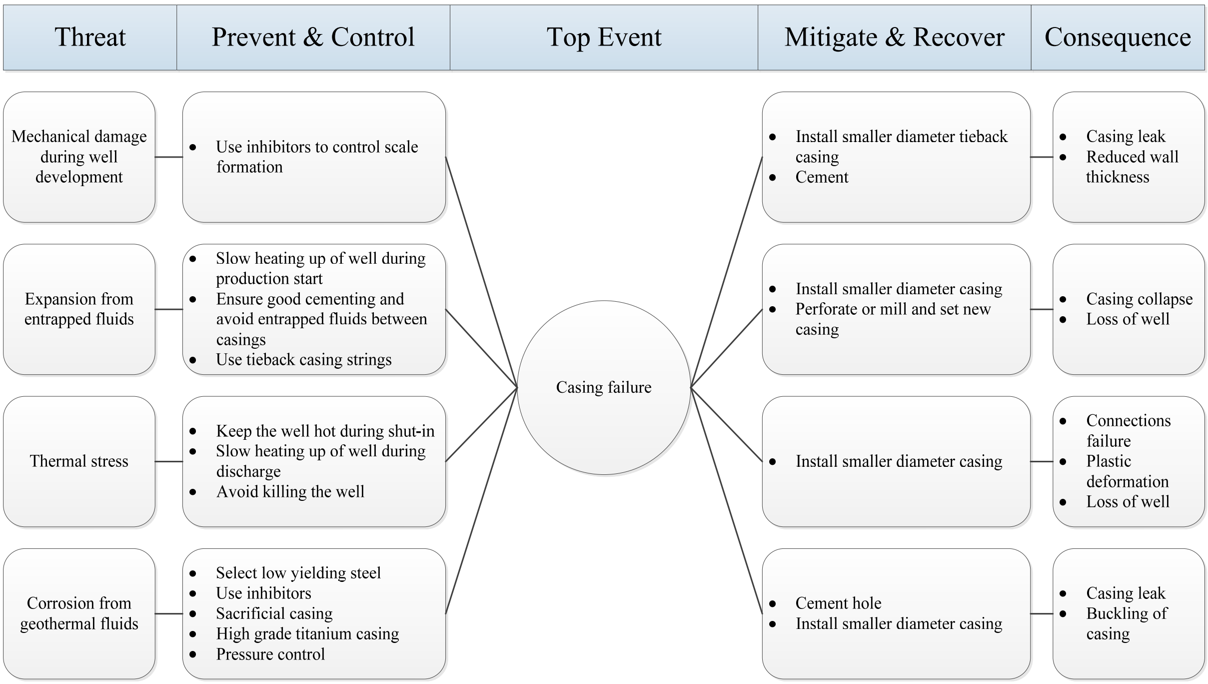


Figure 4-3 Bow-tie diagram showing hazards and mitigating actions for casing failure during the production phase (Snyder, 1979; Southon, 2005; Thorhallsson, 2005), Mannvit (personal communication, April 18, 2017).

4.2.1 Categorization of Risks

The identified risks are gathered and arranged according to risk level using a risk matrix and aligned in an interview with Mannvit (personal communication, April 18, 2017) and presented in Table 4-1. The rating for each failure mode is based on the well status after all mitigating actions have been executed. The well is considered to be in the production phase with highly corrosive fluids present, increasing the risk of corrosion. Mechanical damage does not pose a high threat as this is usually caused by the drill string thinning the casing wall in doglegs and bends. Scaling is assumed to negligible. During reaming of the well, the wellhead valves are the most exposed to potential damage. The likelihood of failure from entrapped fluids is considered low assuming a cement bond log showing good bonding between the casing wall and cement. Thermal stress is given the highest risk level due to the detrimental consequences of a failure where the casing fails and the well might be lost.

Cause of failure	Failure mode	Likelihood of failure	Consequence of failure	Risk Category
Mechanical damage during well development	Thinning of casing wall	1	1	
	WH (top 25 meter of well)	2	2	
	Casing leak	1	1	
Corrosion from geothermal fluids	Thinning of casing wall	3	1	
	WH (top 25 meter of well)	3	3	
	Casing leak	3	2	
Thermal stress	Rifting of casing	2	4	
Expansion from entrapped fluids	Casing collapse	1	3	

Table 4-1 Risk Categorization

4.3 *Identifying Leakage Paths*

Summers et al. (1980) identified possible leakage paths from a geothermal reservoir to a hypothetical aquifer and included leak through a casing, migration from reservoir through formation and from the top side equipment. A barrier diagram consisting of a leak path diagram visualizes possible flow paths of formation fluids from the reservoir to the surroundings. The barrier diagram is related to the WBS in Figure 4-1 and they share the same colour scheme with blue as primary barrier and red as secondary barrier. The diagram in Figure 4-4 shows possible leak paths, one leading through the wellhead and another through the casing, cement and formation. Also, it might be worth noting that the casing connections and wellhead assembly are not gas tight, Mannvit (personal communication, April 18, 2017). The anchor casing is interpreted as a secondary barrier above 400 m against the nearby aquifer. The casing head flange and expansion spool are considered as part of the wellhead at surface. The degraded well barrier element is visualized by a dotted gray colour scheme.

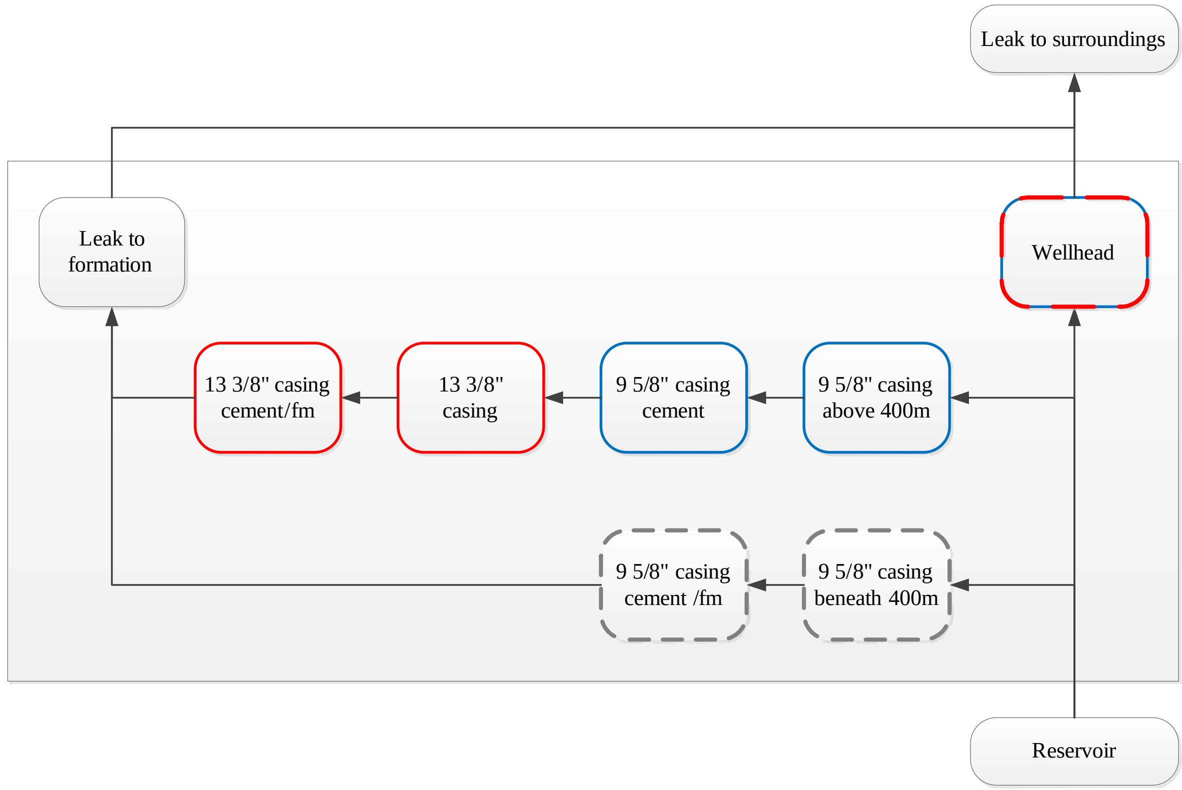


Figure 4-4 Barrier diagram (leak path diagram) adapted from (Okstad & Sangesland, 2009).

4.4 *Risk Management of Downhole Corrosion*

Downhole corrosion has been detected in several wells in the Cerro Prieto field in Mexico (Ocampo-Díaz et al., 2005). The risks associated with a given production well is case dependent and will vary due to factors such as well construction, temperature and lithology. For instance, geothermal wells above 240°C in igneous rocks are managed with different risk factors than low temperature wells, Mannvit (personal communication, April 18, 2017).

A hypothetical downhole corrosion problem has caused a leak in the casing at 1150 meters depth after 5 years of production. In the event of a casing leak the main concern is production of low enthalpy fluid, since the risk of fluid migration in the basaltic formation is generally regarded as very low, Mannvit (personal communication, April 18, 2017). The concern with low enthalpy fluids has been selected as the main focus for the case study. Figure 4-5 shows the status of the well barrier with the casing hole indicated.

The following sections assess the cause of failure, consequence of failure, mitigating actions and suggest preventative measures regarding a hole in the casing wall.

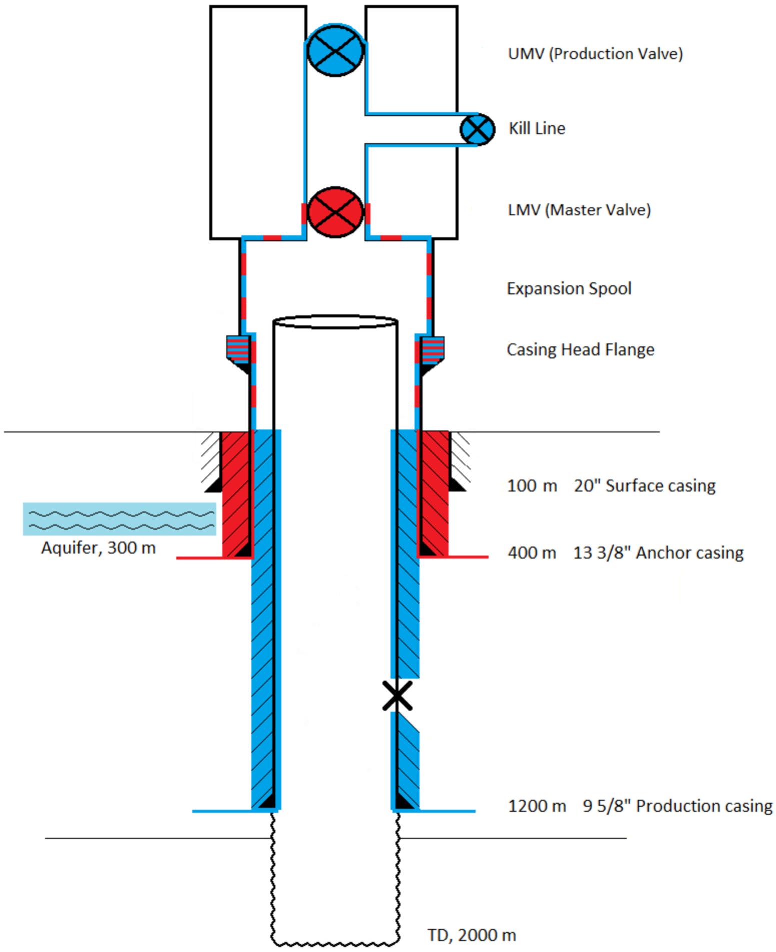


Figure 4-5 Well barrier status (not to scale)

4.4.1 Cause of Failure

It is assumed that monitoring of the wellhead shows a significant decrease in temperature. Investigating the cause of the temperature drop at depths this close to the production casing shoe will require a borehole video inspection for definitive proof. This will require shut-in of the well and injection of clean water. Temperature logs will not be sufficient as the cement may have fractured and fallen out of the annulus, allowing fluid to migrate down the annulus and enter the well at the casing shoe, S. Þórhallson (personal communication, May 8, 2017).

The cause of failure could be due to both external and internal corrosion (Ocampo-Díaz et al., 2005). It is assumed that the borehole inspection video does not show significant damage inside the casing and therefore the damage is most likely caused by external corrosion. Also, it is assumed that the intermittent caliper log surveys do not show any anomalies inside the casing. During the production phase the risk to zonal isolation is at an increased level (Shadravan & Shine, 2015), and external corrosion would most likely mean that the cement sheath of the casing has failed. The most probable cause of such failure is thermally cracked cement, given the frequency of the issue in high temperature environments, S. Þórhallson (personal communication, May 8, 2017) & J. Southon (personal communication, May 19, 2017). The thermal cyclic loads can cause the bond between the casing and cement to be lost, allowing corrosive fluids to attack the external casing wall through micro fractures (Kosinowski & Teodoriu, 2012). According to J. Southon (personal communication, May 19, 2017) cement deterioration due to high CO_2 contents is difficult to prove.

Temperatures are very stable in high temperature reservoirs. A low enthalpy fluid would therefore most likely originate from a nearby injection well through a fracture network in the basaltic formation, S. Þórhallson (personal communication, May 8, 2017).

4.4.2 Consequence of Failure

4.4.2.1 Immediate Consequences

A casing leak could cause either a release of production fluid or influx from the formation. Should a hole in the casing occur, the main concern is the influx of low enthalpy formation fluids. This could lead to a decrease in production fluid enthalpy with a decrease in power production and financial loss as a result, Mannvit (personal communication, April 18, 2017). As opposed to the oil and gas industry, there are no defined leak rate limits in the geothermal industry. The geothermal fluids are non-flammable and do not present comparable hazards, S. Þórhallson (personal communication, May 8, 2017). Local regulations may apply, and leaks are generally not acceptable in cases of leak to an aquifer or issues with the well control, J. Southon (personal communication, May 19, 2017).

Should the decrease in enthalpy of production fluids be within acceptable limits, the casing leak can be ignored provided negligible financial losses and continuous monitoring of temperature, Mannvit (personal communication, April 18, 2017). Assuming an insignificant drop in wellhead pressure, a decrease in enthalpy will directly affect the revenue of the well. The decision of when to repair the damaged casing depends on the projected decline in revenue and the rate of the decline. Due to the depth of the casing hole it is unlikely to be any additional safety risks or aquifer contamination risks, and this is not considered to be a problem requiring immediate action, J. Southon (personal communication, May 19, 2017).

4.4.2.2 Potential Consequences

The risk of migration along the wellbore to surface is generally negligible but it must be monitored on a regular basis. However, as micro fractures are likely present in the cement due to thermal cycling, the risk of geothermal fluid migration along the wellbore increases. CO_2 degradation of cement is localized and is unlikely to cause a migration of fluid along the wellbore to surface, J. Southon (personal communication, May 19, 2017).

It is expected that the effects of diluted corrosive fluids in the production fluid is negligible except for the immediate area around the hole. While the well is producing there is a low risk of aggressive expansion of the corrosion. Should the well be shut in, low enthalpy corrosive fluids are likely to flow down and attack the well below the hole, J. Southon (personal communication, May 19, 2017).

The hole in the casing at this depth is unlikely a well control problem that could lead to plug and abandonment. The risk of increased hole diameter due to erosion from volcanic rock fragments is unlikely, given a stable and solid formation. Dissolved solids could appear in a basaltic formation immediately after the production first commences but is expected to decrease to nothing. Erosion from a high velocity production fluid is highly unlikely and the corrosion product from the casing should not cause further damage to the casing. Should the hole in the casing develop to a larger hole it may be difficult to repair. The worst-case scenario is the casing splitting into two sections requiring the well to be side tracked, followed by the cementing of a liner, J. Southon (personal communication, May 19, 2017).

4.4.3 Mitigating Actions

The uncertainty as to what caused the casing damage is often a challenge when determining how the situation should be handled, S. Þórhallson (personal communication, May 8, 2017). Should it be deemed necessary to plug the hole, cementing and installing a smaller diameter casing is often regarded as the preferred solution, Mannvit (personal communication, April 18, 2017), S. Þórhallson (personal communication, May 8, 2017) & J. Southon (personal communication, May 19, 2017). A scab liner consisting of a smaller diameter corrosion resistant alloy casing, would normally be placed and cemented across the leak zone, J. Southon (personal communication, May 19, 2017).

4.4.3.1 Failure Mitigation and Associated Challenges

The challenge with this damage is the location of the hole close to the production casing shoe at 1200 meters. The scab liner length below the hole at 1150 meters would be short, approximately 30 meters. This would however not prevent the risk of corrosive low temperature fluids migrating down to the casing shoe, negating the effect of the scab liner, J. Southon (personal communication, May 19, 2017).

The cost of the repair depends on the method and the well life expectancy after the repair. A chrome alloy casing will last longer and cost more while a cheaper, plain carbon steel casing has a chance of leaking again within the same timeframe as the first casing leak. There is also a chance for the hole not getting properly covered or the new casing allowing migrating corrosive fluids to pass over or under the repaired area, J. Southon (personal communication, May 19, 2017). Also, as the production rate is proportional to the limiting factor of the casing size (Thorhallson, 2008), a decrease in output should be expected.

As the problem in this well occurred after well completion, a proposed solution is to install a drillable, high temperature packer roughly 50 meters below the production casing shoe. An illustration of the solution is in Figure 4-5. Above the packer, 20 to 30 meters of cement could be placed, followed by running and cementing a scab liner from the top of this cement and up to approximately 50 meters above the damaged area, J. Southon (personal communication, May 19, 2017).

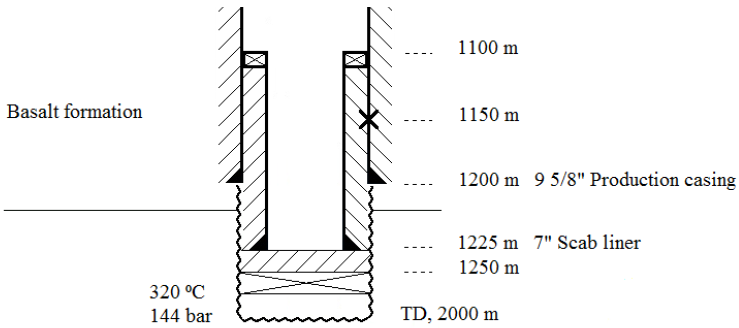


Figure 4-6 Illustration of a proposed solution to the casing damage.

4.4.4 Preventative Measures

During well design, more preventative measures could be considered to reduce the risk of casing damage due to aggressive corrosion. In Salton Sea they used a higher casing grade, a Beta-C titanium casing to deal with the corrosive environment (Pye et al., 1989). Using a higher casing grade would give a more corrosive resistant casing, sometimes corrosion immune. This would need testing to the specific geothermal environment. Also, increasing the casing wall thickness would increase the corrosion resistance over time (Hodson-Clarke et al., 2016) In the Philippines a sacrificial casing was installed and for IDDP-1 it was installed as a measure against thermal cycling, Mannvit (personal communication, April 18, 2017).

If the location of the corrosive fluid was known to be at 1150 meters, a chrome alloy casing could be placed across this zone and down to the production casing shoe. Knowing this, the production casing shoe should probably have been installed at a depth deeper than 1200 meters, J. Southon (personal communication, May 19, 2017).

5 Summary of Results and Discussion

The method for determining the results in the thesis was primarily interviews supported by a literature review and testing the risk assessment method on the theoretical geothermal well. The findings reflecting the objectives of the thesis are discussed in the following sections. The risk assessment methodology's applicability for the geothermal well is discussed first, followed by a discussion and summary of findings from the case study.

5.1 *Risk Assessment Methodology*

The results of investigating the applicability of risk assessment methods from the petroleum industry on the theoretical geothermal well can be summarized as follows:

- The risk assessment tools from the oil and gas industry have been applied for a geothermal well with some adjustments due to well design.
- Geothermal wells often produce directly through the casing, instead of through a production tubing, making it difficult to identify two independent barrier envelopes.
- NORSOK D-010 is not limited to oil and gas wells even though geothermal wells are not considered in the standard.
- The barrier diagram turned out to be a simpler diagram than for a petroleum well due to the well construction.
- Applying the assessment on other wells may give different results.

In this thesis, risk assessment methods from the petroleum industry have been applied to a geothermal well integrity problem. High temperature geothermal wells may have well integrity issues that are not common in conventional oil and gas wells, and this must be taken into consideration. The adjustments to the petroleum industry methods have been made to account for the geothermal well design and the high temperature exposure. When defining the well barriers for the geothermal well an interpretation based on NORSOK D-010 was performed as this is considered a valuable tool in risk assessment procedures in the petroleum industry. The methodology used in this case study may be applicable for other geothermal well designs and other phases of a well's life cycle. This will have to be verified by further studies.

The barrier diagram resulted in a simpler schematic compared to that of a petroleum well, and more complex well design will require a more comprehensive schematic. It can however still be a useful tool for showing the status of the barrier elements and indicating potential leakage paths.

The qualitative risk analysis relies heavily on the knowledge and experience of the participants in the interview. The participants' backgrounds are limited to personal experience and not all backgrounds are covered in the study. As an example, professions such as geophysicists and geologists have not participated. The variation in backgrounds was evident in some of the replies. The respondents may interpret the questions differently, as well as the actual case, and this could be a source for misunderstandings.

The case is based on an actual well design. However, due to the lack of information in the reviewed literature regarding both design parameters and integrity problems for a specific well, the chosen well integrity problem in this study is hypothetical and based on the reviewed literature. An actual case would reduce the number of assumptions and increase the viability of the risk analysis. Quantitative data such as statistics about well integrity problems would be valuable input to the risk assessment. The case study is still a realistic study as it is based on published information and verified by experienced personnel through interviews.

5.2 *Interpretation of Well Barriers in Geothermal Wells*

The results of the well barrier interpretations in the case study are:

- The production casing and cement are regarded as the primary barrier and the anchor casing and cement as the secondary barrier, protecting against a nearby aquifer (DiPippo, 2016).
- The high temperature well includes a common well barrier element at the wellhead.
- Upper master valve is defined as the primary barrier while the lower master valve is defined as the secondary barrier.
- Defining the wellhead valves is a matter of definition left to the operator.

Identifying and classifying a well barrier creates a better understanding and overview of the well. Well barrier schematics are helpful tools for readers to understand the well construction, and in a risk management scenario they can be used to visualize where the barrier failure occurred.

It could be argued that defining anchor casing as secondary casing would require a component such as a downhole safety valve in the production casing, preventing the wellhead from becoming a dual barrier, to follow NORSOK D-010 requirements. This is however a matter of definition and NORSOK D-010 allows for dual barrier in under-balanced drilling and snubbing operations, given that the dual barrier is strictly monitored. Consequently, this interpretation could be applied to geothermal wells and enables the interpretation of the anchor casing as secondary barrier against aquifers, which is also in alignment with the literature review and conducted interviews.

The well barrier schematics in Figure 5-1 illustrate different definitions of well barrier interpretations. The UMV, kill line and the LMV are potential primary or secondary barriers. For the sake of simplicity, the LMV could be defined as a dual barrier (A) due to the fact that there would be less valves defined as barriers requiring periodic testing according to NORSOK D-010. The UMV could be defined as a secondary barrier (B) as this is remotely operated and thus part of the secondary barrier envelope. Since the LMV requires manual handling, the UMV could be identified as primary barrier (C) as this works hydraulically. This would be a workover situation where the LMV can be closed while the upper valves are changed. Interpretation of the valves depends on the definition set by the operator, although there are no definitive answers.

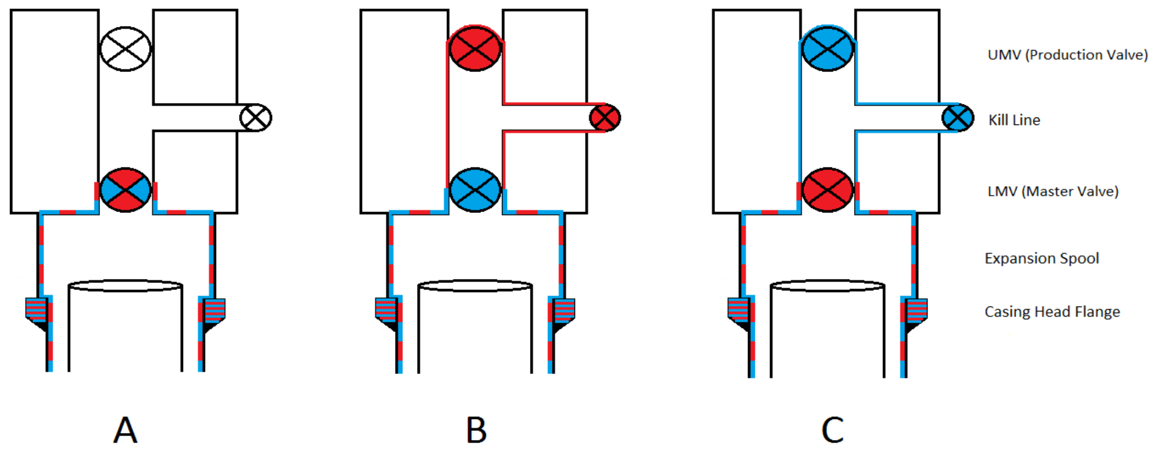


Figure 5-1 WBS of wellhead valves, showing possible definitions of WBE’s.

This well barrier interpretation is valid for the production phase of a geothermal well. Wood Group et al. (2016) investigated barrier interpretation of low enthalpy wells requiring a pump for production and defined the fluid column as primary barrier. This would not be valid for this high temperature well as it has self-flow. Other variables affecting the barrier interpretation could be the number of valves, valve placement and expansion spool. In wells where the production casing is used as anchor casing further analysis may be necessary.

5.3 *Case Study Findings and Discussion*

The results of the risk assessment of a downhole corrosion problem in a theoretical geothermal well are:

- The main concern of a downhole casing leak at the studied depth is the production of low enthalpy fluids.
- Considering the consequences in the production phase, most concerns are financial.
- The environmental consequences of a casing leak in a basalt formation at the studied depth are low as the likelihood of fluid migration is considered low.
- Human safety is considered low risk during normal production as there are no personnel in the vicinity.
- Downhole corrosion only affects a few number of high temperature wells in Iceland.
- If detected, casing leaks are repaired as soon as possible.
- In contrast, a minor casing leak could be ignored if the impact is very low.
- Thermal cracking of cement is the most probable cause of cement failure.
- A cement bond log will not give definitive proof of cement degradation being caused by CO_2.

Lohne et al. (2016b) indicated that the petroleum industry appears to have a higher focus on well integrity and well barriers compared to the geothermal industry, due to the limited amount of published literature regarding the subject found in this study. However, several papers focus on casing integrity but there is limited use of the term well barrier. Environmental and human safety consequences seem to be of a higher concern in the petroleum industry. The geothermal fluids do not pose the same level of hazard and personnel are usually not in the vicinity of a geothermal well during production. Should something happen to the well, the area of most concern is therefore the financial impact.

The likelihood of downhole corrosion will depend on the chemical environment and may vary within the same geothermal field. The reviewed literature indicates that corrosion is a large problem in geothermal wells, however one of the respondents suggested this not being a common problem and that wells in these environments should be avoided. Thermal cracking of cement appears to be a more likely, and more frequent, problem in geothermal wells exposing the casing wall to corrosive fluids. Krilov et al. (2000) found that external corrosion could be due to CO_2 degradation of cement, this was deemed unlikely and difficult to prove as a cause of failure with a cement bond log. In contrast to the literature review (Edwards et al., 1982), the cement sheath should probably not be regarded as protection against external casing corrosion due to the micro fractures developing in the cement under thermal stress.

The main respondent indicated that influx of low enthalpy fluid is the biggest concern, directly affecting the revenue of the well. It was suggested that the hole could be left alone if the leak was small. On the other hand, a second respondent indicated that casing holes should be repaired when they are discovered. A decision analysis could be useful in determining whether repairs should be carried out. Comparing revenue from a presumably healthy well versus a well with a casing hole and decreased enthalpy output, and checking this against the cost of repair and subsequent decrease in output, a comparison can be made between the options. A Monte Carlo simulation could benefit the decision analysis, and preferably a real case should be available for comparison.

The selection of available innovative solutions is significantly narrowed by the high temperatures in the well. Preventative measures in the form of coated casings and non-metallic casings are not, to the author's knowledge, available for temperatures of 320°C.

As suggested by Wood Group et al. (2016) a tied back liner fixed to a PBR would create a closed annuli between the tied back liner and the production casing. This could probably reduce the risk of corrosive fluids migrating down to the production casing shoe and into the well as the annulus would then be closed.

6 Conclusion and Recommendations

In this study, the implementation of risk assessment tools such as well barrier schematics, risk matrix, barrier diagrams, bow-tie and influence diagrams proved useful in assessing risk in a geothermal well. Qualitative risk assessment methods from the petroleum industry helps to visualize and simplify barrier control, and the methods have been found applicable for geothermal wells in this thesis. Based on the well design differences, minor adjustments in well barrier schematics and the barrier diagram have been applied. Further it is believed that this qualitative risk assessment method can be used in any geothermal well design, this will need to be verified.

Implementing well barrier schematics in risk management of geothermal well integrity issues has proven a helpful tool in this study and in alignment to the literature. NORSOK D-010 was found applicable as guidance for geothermal wells, even though these wells are considered in the standard. The standardized well barrier schematics from NORSOK D-010 include elements such as valves, casings and colour schemes that can be applied to geothermal well barrier schematics. Further work of establishing standardized well barrier schematics could benefit risk assessment of geothermal wells.

This study shows that the investigated well may consist of a primary and a secondary barrier envelope with a common well barrier element at the wellhead. The well design in the case study is based on a typical Icelandic high temperature well and it is believed that the barrier interpretation could be used in wells with similar conditions. The area with the most design variables concerning barrier interpretation would be at the top part of the well such as the number of valves, valve placement and expansion spool. In wells where the production casing is used as anchor casing further analysis may be necessary.

The risk assessment in this study indicates financial risk to be the area of highest impact concerning well integrity issues. Interviews and literature review show that the environmental impact of downhole corrosion in a geothermal well is not considered as high a risk compared to an oil or gas well, and the main concern in a downhole corrosion situation in a geothermal well is financial loss. Further study of the risk in other phases of the well's life cycle is recommended.

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Appendix A – Interview Questions

This appendix includes the majority of questions to geothermal experts and their response to the case study. Questions 1-9 were conducted through an interview with Mannvit on April 18th, 2017 in Iceland. Questions 10-34 are from e-mail correspondence with Sverrir Þórhallson, Iceland, who responded May 8th, 2017 and James Southon, New Zealand, who responded May 19th, 2017 as agreed earlier.

1. What are the primary well barrier elements in this well?
2. What can be considered as secondary well barrier in this well?
3. What are the possible leakage paths in this well?
4. What may cause failure of well barrier?
5. What are the mechanisms of failure of the well barriers and what are the factors responsible?

Case: After 5 years of production, a casing leak has occurred in the production casing at 1150 m depth due external corrosion

6. What are the consequences of this failure?
7. What needs to be done to fix the failure?
8. Is it important to avoid it or can it be ignored?

Can be ignored if the water is not too cold

Migration is usually not a problem in geothermal formations

9. Is it probable to happen again?

If it has happened once it will probably occur again

10. Assuming the production goes on, the chemical composition of the influx fluid, could it increase the corrosion aggressiveness internally and would it be considered as high risk?

There are wells in Krafla that have suffered corrosion damage due to acidic fluids. I do not know the details on well KG-26. Either the fluid was low pH ~2,9 and corrosive or there was corrosion down-hole where HCl gas came in contact with water causing dew-point corrosion at the zone of contact. Later dilution with more water higher up in the wells neutralized the acidic fluid so that is non-corrosive at the wellhead, S.Þórhallson (personal communication, May 8, 2017).

It depends on the relative permeabilities of the corrosion causing fluids versus that of the production fluids which is assumed to be benign (non corrosive). It is expected that the dilution effects of the production fluids is greater than the corrosive fluids and therefore, the corrosive influx would be localised, i.e. it doesn't pose a high risk of aggressive expansion of the corrosive effect while the well is producing. However, if the well is standing shut it is likely that the low enthalpy corrosive fluid will flow downwards and corrode the casing below 1150 m, J. Southon (personal communication, May 19, 2017)

11. Could the production contain solids/minerals considering it is a basaltic formation considering erosion and erosion corrosion?

The velocity is probably not high enough to cause erosion damage. Please check the velocity knowing the mass flow, fluid enthalpy and wellhead pressure. From this you can look-up the two-phase density and calculate the down hole pressure profile and hence the velocity vs. depth, S.Þórhallson (personal communication, May 8, 2017).

After the initial discharge the fluid is very clean and erosion damage very uncommon. Yes, immediately after production first commences. If the basalt formation is stable and solid, ongoing solids percentages of the production fluid should drop off to nothing. J. Southon (personal communication, May 19, 2017)

12. In general, could erosion from the high velocity production fluid could increase the hole in the casing wall?

It is highly unlikely. I am currently working on a very productive liquid phase (about 1500 kj/kg) well with corroded casing and there is no evidence of fluid erosive effects at the corroded areas (as confirmed by downhole camera work). J. Southon (personal communication, May 19, 2017)

13. Would the corrosion product from the casing cause further damage to the well?

The liner has corroded to destruction in a few well due to dew-point corrosion and caused down-hole blockage. Do not know the situation with KG-26, S.Þórhallson (personal communication, May 8, 2017).

14. What is the approximate distance from the well to an aquifer when the aquifer needs to be considered in well design (location)?

Do not understand the question. If you are referring the geothermal aquifer the well needs to intersect it in order to be productive, S.Þórhallson (personal communication, May 8, 2017).

0 km. A number of geothermal wells have to contend with penetrating corrosive formations. It is probably the nature of geothermal environments, especially when penetrating thermally altered formations. J. Southon (personal communication, May 19, 2017)

15. Could the formation subside over time when producing?

Subsidence of less than 1 m has been measured in Svartsengi and there is a levelling network at Krafla. The subsidence would be less there as there is not as much draw-down. Do not expect any adverse effects. One well in Krafla was "bent" due to an earthquake and could not be re-entered with a stiff drill string. That was due to the ground shifting to one side, S.Þórhallson (personal communication, May 8, 2017).

Yes. Wairakei, the first water dominated geothermal reservoir exploited for electricity, produces from and below volcanic formations. The Huka mudstone is a lakebed formation that caps the reservoir. However, it is my understanding that volcanic formations below the mudstone is responsible for most of the settlement (more than 8 m of subsidence at the surface) as a result of pressure drawdown below the mudstone. At least one paper has been published on this topic. J. Southon (personal communication, May 19, 2017)

In most geothermal developments, it is a common practice to inject brine and condensate left over from the energy conversion process (for liquid dominated systems). I am not familiar or have knowledge where additional "cold" water is injected into a reservoir to make up for the the losses in a reservoir during electricity production. My experience deals with Indonesian fields where electricity is produced from steam dominated systems and cold water is not added to the condensate that is injected into the reservoir. . J. Southon (personal communication, May 19, 2017)

16. Where could the colder water originate from?

There is great temperature stability in HT reservoirs. The most pronounced effects are from draw-down due to prolonged fluid production and some chemical changes. The most likely cooling is from a nearby reinjection well – break-through-through a fracture network (anisotropic flow), S.Þórhallson (personal communication, May 8, 2017).

17. Are corrosion inhibitors injected continuously or in batches?

Corrosion inhibitors are never used. Corrosion on well casings is limited to very deep and hot wells that intersect acidic fluids. Wells last > 50 years if properly operated and maintained, S.Þórhallson (personal communication, May 8, 2017).

This is not part of my experience or knowledge. For casing corrosion, inhibitors are <u>not normally injected</u> for combating the corrosion. J. Southon (personal communication, May 19, 2017)

18. Are corrosion inhibitors the same as used in oil and gas industry, or are they designed for the high temperatures?

No inhibitors required, S.Þórhallson (personal communication, May 8, 2017).

19. How do you decide if/when it is necessary to fix the leak? Do you evaluate costs, temperature, drop in efficiency etc., or do you just base it on experience?

a) Drop in well mass flow.
b) Drop in WHP below power plant steam system pressure.
c) Not being able to log or ream with a drilling rig (workover).
d) Steam leakage to surface or into annulus.

S.Þórhallson (personal communication, May 8, 2017).

I presume “the leak” that you are referring to is the hole in the casing at 1150m. It is close to the shoe of the casing. Normally a smaller diameter corrosion resistant alloy casing (called a scab liner) is inserted across the leak zone and cemented in place. The problem with this case is that the scab liner length will be short (about 30 m) below the leak at 1150 m. This leads to a risk that low temperature corrosive fluids will flow down behind the main casing or the scab liner to the shoe of the casing, negating the effects of installing the scab liner. . J. Southon (personal communication, May 19, 2017

20. What uncertainties makes it hard to tell what would be the best solution?

Not knowing the nature or cause of the damage. Borehole video confirmation is most useful in the analysis. Need to kill the well and inject clean water, S.Þórhallson (personal communication, May 8, 2017).

It seems that the 9-5/8” casing shoe should have been deeper in the first place. However, given that this problem developed after completing the well, the better solution is to set a drillable high temperature packer say 50 m below the 9-5/8” production casing shoe, place 20 to 30m on top of this packer and run and cement the scab liner to this depth and, say, 50 m above the corroded section. J. Southon (personal communication, May 19, 2017)

21. How do you perform calculations on estimating the development of the leakage? (predictions) - if you do so

Flowing temperature survey will reveal where there is a cold inflow and roughly how much (calorimetry). Spinner survey may also be useful, S.Þórhallson (personal communication, May 8, 2017).

There are casing survey tools that can be run in hot wells, eg Kinley caliper and HTCC (MB Century). Annual or semi-annual surveys on the casing should give a measure on the rate of corrosion. It takes away the guess work but the surveys are not cheap. I would not rely on calculations as this can vary from case to case. By doing regular casing surveys you will know the corrosion rate working back from the when a hole appears in the casing. J. Southon (personal communication, May 19, 2017)

22. How quickly would the size of the hole increase? Linearly, exponential or logarithmic (in general)?

Holes are very uncommon and if detected are repaired as soon as possible. No catastrophic holes, S.Þórhallson (personal communication, May 8, 2017).

This is academic and fine if you wish to be a researcher. The real world of owning and running geothermal wells and power stations does not work that way. J. Southon (personal communication, May 19, 2017)

23. What are the acceptable leakage limits, if there are any (regulations, guidelines, etc.)?

No set limits. Geothermal fluids are non-flammable and leakage does not pose the same hazard, S.Þórhallson (personal communication, May 8, 2017).

In geothermal developments, I am not aware of regulatory control on leakage rates. Leakage is generally not acceptable by regulators (here in NZ) if it contaminates a particular aquifer or b) if it is a well control issue. J. Southon (personal communication, May 19, 2017)

24. Is it 100% <u>safe</u> to produce under the circumstances? (producing colder fluid from the leak point) Meaning, no additional human safety risk or environmental risk

Like I have said before leaks are very rare on geothermal wells. On surface the leaks on valve spindles and flanges are taken care of by maintenance crews as soon as possible. Down-hole leaks are rare and the wells have been quenched before any damage and repaired by re-lining (cemented liner), S.Þórhallson (personal communication, May 8, 2017).

In the case presented for this questionaire, there is unlikely to be additional safety (well control) or aquifer contamination risks. This is due to the depth of the hole (50 m above the shoe of the production casing). J. Southon (personal communication, May 19, 2017)

25. Is it a risk that requires immediate action?

No – no urgency J. Southon (personal communication, May 19, 2017)

26. How long would you assume until things will go worse if the leak is not repaired?

The greatest impact should be on your revenue stream from this well. The economics of the loss of revenue, and the decline rate in the revenue, should determine the turning point. J. Southon (personal communication, May 19, 2017)

27. What is the risk of migration along the wellbore to <u>surface</u>?

CBL is run on all cemented casing string for QC when the well is being drilled. CBL in old wells in not possible due to tool temperature limitations. The bonding is also broken at high temperatures so the CBL log will be inconclusive. Quenching of wells is only done as a very last resort due to danger of casing damages. Most common log it PT log with a high-temperature memory tool. Wire baskets are run as "godevvils" to check for down-hole obstructions, S.Þórhallson (personal communication, May 8, 2017).

CO2 degradation of cement is likely to be localised. The cement does not disappear, especially if silica is included. It is unlikely breaches to the surface through the cemented annular space will occur that can be attributed to CO2 degradation. I am not aware if that has occurred in the thousands of geothermal wells that have been drilled in CO2 rich environments. A CBL would not be an appropiate tool to determine or detect CO2 cement degradation. Furthermore you have made the assumption that the corrosion of the casing has been due to CO2 degradation of the cement. J. Southon (personal communication, May 19, 2017)

It is a fallacy to consider cemented annular spaces as means of protecting casing from corrosion attack in geothermal wells. Once a well heats up and then undergoes thermal changes when production commences (or stops), the cement bond to the casing surface is broken. The casing steel has very different engineering properties to that of cement when subject to temperature changes. Cement shear, tensile and compressive strength is inferior to that of steel. Not only has the bond to the casing been broken, the cement sheath will have developed micro fractures due to it being subjected to applied loads of the casing, which trying to expand or contract. There is a large amount of research being done on improving cement mixes to withstand such damaging effects. J. Southon (personal communication, May 19, 2017)

28. What is the risk of migration to the aquifer located at 300 m depth?
a) Assuming the well is healthy
b) The leakage case in mind (considering corrosive production fluids and degraded cement)

When the well is shut-in, it is expected that there will be a downflow from the cooler corrosive fluids to the hotter deeper fluids. This can be verified with using a (pressure, temperature and spinner) PTS tool. J. Southon (personal communication, May 19, 2017)

The cement in the annulus is fractured from the thermal stresses. Leakage is not a problem in spite of this. Has been repaired on one well with a collar and a cement squeeze. We have over 200 HT wells in Iceland and very few wells have any such issues – only wells drilled very deep and into temp >310°C and into acidic fluids. Something to stay away from in my opinion, S.Þórhallson (personal communication, May 8, 2017).

Microfractures in the degraded cement would increase the risk of geothermal fluids migrating along the wellbore, J. Southon (personal communication, May 19, 2017)

29. What is the risk of CO_2 causing damage on the cement in the future?

How do you know that CO2 caused the damage to the cement? All you know is that corrosive fluids have attacked the steel in the casing and the evidence is that you have a hole in the casing letting in cooler fluids. It is simplistic to say that the attack on the casing was due to CO2 degradation of the cement sheath. J. Southon (personal communication, May 19, 2017)

30. What is the worst-case scenario from the leakage?

Losing control of the well. Has happened once, well 4 in Krafla. It self-healed in half a year but a total loss, S.Þórhallson (personal communication, May 8, 2017).

Too large hole to fix? No. A large hole may be more difficult to deal with and hence one should not let the hole develop such that the casing is split in two. J. Southon (personal communication, May 19, 2017)

Need to sidetrack ? No – only if the casing has split in two.. J. Southon (personal communication, May 19, 2017)

Smaller OD casing inside? Best option if you can tackle this option early. J. Southon (personal communication, May 19, 2017)

P&A? Unlikely to be a well control problem for this option to be exercised. The worst-case scenario is when the casing is corroded into two sections. This may force you from a scab liner option to a side track (and followed by the cementing of a liner). J. Southon (personal communication, May 19, 2017)

31. Would the risk of concentrations of stress in the metal be increased?

Thermal stress and temperature cycling is a serious problem at very high temperatures ~>310°C. Breaks at casing joints is known to occur (3rd thread from inside the coupling), S.Þórhallson (personal communication, May 8, 2017).

At this depth and temperature – no. Thermal stresses are often due to the delta T affect (temperature at which cement sets (expected to be high) and temperature of production (expected to be high) at these depths, J. Southon (personal communication, May 19, 2017)

32. What could/should have been done differently?

If you knew the corrosive was at 1150 m, you could have placed chrome alloy casing across this zone to the shoe and possibly gone deeper that 1200 m with the shoe, J. Southon (personal communication, May 19, 2017)

33. What tools/methods are applicable to repair the leak?

Cementing (squeeze cementing), installing a smaller diameter casing and scab liner. Squeeze cementing then cemented scab liner (not to the surface – just sufficient to cover the problem zone, J. Southon (personal communication, May 19, 2017)

For a successful job that I have just completed, we ran a 350 m scab liner, consisting of 7-5/8” OD 2507 duplex stainless steel casing inside 1100 m of 9-5/8” 47 lb/ft L80 casing (from 650 m to 1000 m), J. Southon (personal communication, May 19, 2017)

34. What new tools/methods could possibly be applicable to repair the leak (do you have any thoughts for this high temperature well)?

I believe we will be sticking with carbon steel (CS) as casing material for HT geothermal wells, S.Þórhallson (personal communication, May 8, 2017).

Non-metallic tubing? Don’t know of such materials that can withstand 320 deg C, J. Southon (personal communication, May 19, 2017)

Coating of the tubing? Don’t know of such materials that can withstand 320 deg C, J. Southon (personal communication, May 19, 2017)