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To dad,

You were the greatest dad a girl could ever wish for.

I miss you dearly.

Abstract

During the next decades, a large number of wells needs to be plugged and abandoned on the Norwegian Continental Shelf (NCS). The cost of plugging these wells will be enormous (Straume, 2014). One of the elements that affects the costs related to P&A is the regulations. Today, the regulations are in practice prescriptive. However, this thesis studies the possibility and the benefits of having a risk-based regulation for P&A. The essence is then to measure the quality of different P&A solutions in terms of leakage rate and probability. Then it would be easier to accept new solutions for P&A and use cheaper solutions if these were considered safe enough. Performing a risk assessment of P&A wells would also give the industry valuable knowledge about the risk associated with plugged and abandoned wells.

If a risk-based regulation for P&A were to be implemented, then the risk acceptance criteria should be established. Risk acceptance criteria tells us whether the risk is acceptable or not. The recommended solution is to use the ALARP triangle, where the consistency between wells method reflects the lower criterion and the natural seepage rate reflects the upper criterion (see figure 1). In the ALARP region, one should aim to reduce the risk to a level that is As Low As Reasonably Practicable (Aven, 2015).

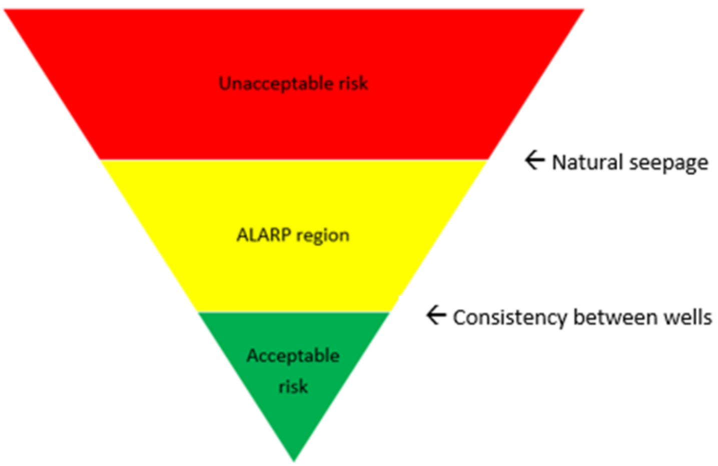

Figure 1. Recommended solution on how to establish risk acceptance criteria for P&A wells.

The consistency between wells method estimates the leakage rate for a worst case well abandoned according to regulations. This is identified as best practice, as this would replace today's requirements in terms of leakage rate. Natural seepage rate should reflect the higher criterion. The leakage rate from natural seeps is considered acceptable as these rates are quite low, giving the marine environment time to adapt into the new conditions. In addition, the leakage from natural seeps is permanent (long-lasting), which would also be the case for P&A wells, as no one is there to stop the leakage (due to no monitoring). However, allowing the same leakage rate as natural seeps would disturb the natural balance and one should therefore reduce the risk unless the costs are in gross disproportion to the benefit gained.

As mentioned earlier, performing a risk assessment of P&A wells includes quantifying the probability of leakage and the leakage rate. To quantify the probability of leakage, the recommended solution is to use a Bayesian approach together with the Weibull distribution. This method allows the use of only censored data as there are no leaks reported in P&A wells on the NCS. With this approach, one can also include prior information available from experts, models etc. In addition, this method takes into account that the probability changes with time, as one assumes an increasing failure rate.

To quantify the leakage rate, a leakage calculator has been developed by Ford et al. (2017). The leakage calculator has two sets of inputs; deterministic (fixed values such as plug length, virgin reservoir pressure etc.) and uncertain (such as cement permeability, fracture width etc., represented using a probability distribution). This leakage calculator currently considers the following leakage paths: through bulk cement, fractures/cracks and in the micro-annuli. The calculator then integrates this information in order to describe the overall leakage rate potential for a failed permanent barrier system (Ford et al. 2017).

Lastly, a case study was performed. The result of this case study shows that a shorter plug length for LPLT (low pressure / low temperature) wells should be accepted when plugging these wells. For example, it was shown that a 30 m formation to formation plug for this well would have a leakage rate in the acceptable region. Reducing the plug length from 50 to 30 m would save money as this would require less time.

The conclusion is that a risk-based regulation for P&A will result in cost efficient solutions where the quality is maintained.

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List of Abbreviations

ALARP	As Low As Reasonably Practicable
API	American Petroleum Institute
BOC	Bottom of Cement
FMEA	Failure Modes and Effects Analysis
GOM	Gulf of Mexico
GUI	Graphical User Interface
GWP	Global Warming Potential
HC	Hydrocarbon
HPHT	High pressure, high temperature
LPLT	Low pressure, low temperature
MD	Measured depth
MLE	Maximum likelihood estimator
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
PSA	Petroleum Safety Authority
P&A	Plug and abandonment
ScF	Standard cubic feet
TOC	Top of Cement
TVD	True Vertical Depth
UAC	Upper Acceptable Case
UK	United Kingdom
WBE	Well barrier element

Introduction

During the next decades, a large number of wells need to be permanently plugged and abandoned on the Norwegian Continental Shelf (NCS). Currently, there are around 2 350 wells on the NCS that will require P&A, and 3 000 additional wells are planned to be drilled in the future (DNV GL, 2017). P&A operations are highly expensive, and the industry is therefore eager to find solutions than can reduce costs related to P&A operations. In fact, P&A operations on the NCS will cost approximately 876 billion NOK for the next 40 years with today's technology (Straume, 2014). At the same time, risk (of leakage) is an important issue to consider when these wells are being plugged and abandoned. Oil and gas leak from an abandoned well would affect the environment. In addition, a leak in the well would also be costly to fix. Ultimately, we want quality at the right price.

To ensure quality at lower costs, it could be beneficial to move away from prescriptive P&A regulations and move towards having a risk-based regulation for P&A. Then, the quality of different P&A solutions would be measured in terms of leakage risk (probability and leakage rate). Current P&A regulations are in practice prescriptive, including required numbers and properties for well barriers. In addition, the requirements are the same for all types of wells, even though they would have different risk of leakage. Instead, having risk-based regulations for P&A could give rise to cost efficient solutions where quality is maintained.

This thesis contains an assessment of leakage risk in P&A wells. The first part addresses the regulations related to P&A with respect to barrier requirements, and a discussion of prescriptive P&A requirement vs. a risk-based P&A requirement. Further, natural seepage to seabed is then studied with focus on available data. In addition, available leakage statistics for wells in North America, UK and Norway is processed. If the objective is to move towards a risk-based regulation for P&A well, then defining the acceptable leakage rate is essential. How to define this acceptable leakage rate is then discussed, including different approaches to find a reasonable number requirement to use in a risk-based P&A regulation. Further, methodologies to quantify probabilities and leakage rates are established. Lastly, a case study is performed to show whether a risk-based regulation for P&A could be more beneficial with respect to quality and costs.

1. Regulations and requirements for P&A

This chapter focuses mainly on the requirements and recommended practice for the well barrier system from the PSA regulations and NORSOK D-010 Standards. Today, the requirements and guidelines are in practice prescriptive. In the end of this chapter, it is discussed whether risk-based P&A requirements could be more beneficial compared to prescriptive P&A requirements.

1.1. PSA regulations and NORSOK D-010 Standards

The Petroleum Safety Authority (PSA) of Norway has developed a document about barrier management. With the PSA regulations as background, the NORSOK Standard D-010 has been developed. The NORSOK Standard D-010 acts as a guideline to the regulations and includes recommended practice and requirements on how to fulfil the functional requirements in the regulation.

1.1.1. Temporary and permanently abandoned wells

First of all, wells can be either permanently or temporary abandoned, depending on whether one is considering re-entering the well at a later point in time. According to section 88 (activities) regarding the securing of wells, PSA (2017) states, that an exploration well commenced after 01.01.14, shall not be temporarily abandoned for more than two years. In addition, a hydrocarbon bearing production well abandoned after 01.01.14, shall be permanently abandoned within three years if the well is not monitored continuously (PSA, 2017). However, further in this thesis, only permanently abandoned wells are considered.

1.1.2. Well barrier requirements and properties

PSA (2017) states, that well barriers shall be designed in such a way that the well integrity and barrier functions are ensured and safe for the whole lifetime of the well. It is important to specify that the well's life span also means the time after operators have permanently plugged and abandoned the well. In addition, the well barriers shall prevent unintended outflow to the marine environment, as well as preventing influx to the well. In section 5 about barriers (management part), it is stated that barriers shall, among other things, reduce the chance for failure both occurring and developing. Another aspect to notice in the PSA regulations, is that the operator's liability with respect to safety of abandoned wells, has no time limit unless decided otherwise by the Ministry.

However, if an operator uses other solutions than those recommended in the regulations, then they must document that the chosen solutions fulfils the regulatory requirements (PSA, 2017).

As stated in NORSOK Standard D-010 rev. 4, permanently abandoned wells shall be plugged with an eternal perspective. This includes considering geological and chemical processes which can affect the formation design and pressure in the future, leading to potential leaks.

According to NORSOK Standard D-010 rev. 4, a permanent well barrier shall have these properties:

- Long-term integrity
- Non-shrinking
- Impermeable
- Able to resist mechanical loads/impacts
- Not harmful to the steel tubulars integrity
- Wetting to ensure bonding to steel
- Resistant to chemicals/substances

In addition, the barrier shall be set at a depth where the maximum potential pressure below the barrier does not exceed the formation fracture at the base of the plug (NORSOK Standard D-010, 2013). The barrier shall also be placed across an impermeable formation. The main task for a well barrier is therefore to seal both horizontally and vertically (see figure 2). If the barrier fails, this would result in a loss of zonal isolation, leading to fluids being able to migrate to the marine environment as well as air contamination.

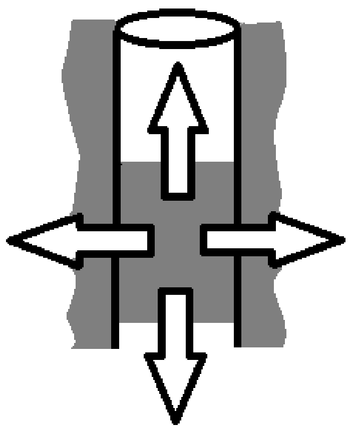

Figure 2. The barrier shall seal both vertically and horizontally (NORSOK Standard D-010, 2013).

1.1.3. Well barrier schematic

Figure 3 shows a schematic of the well barrier system, according to NORSOK Standard D-010 (2013).

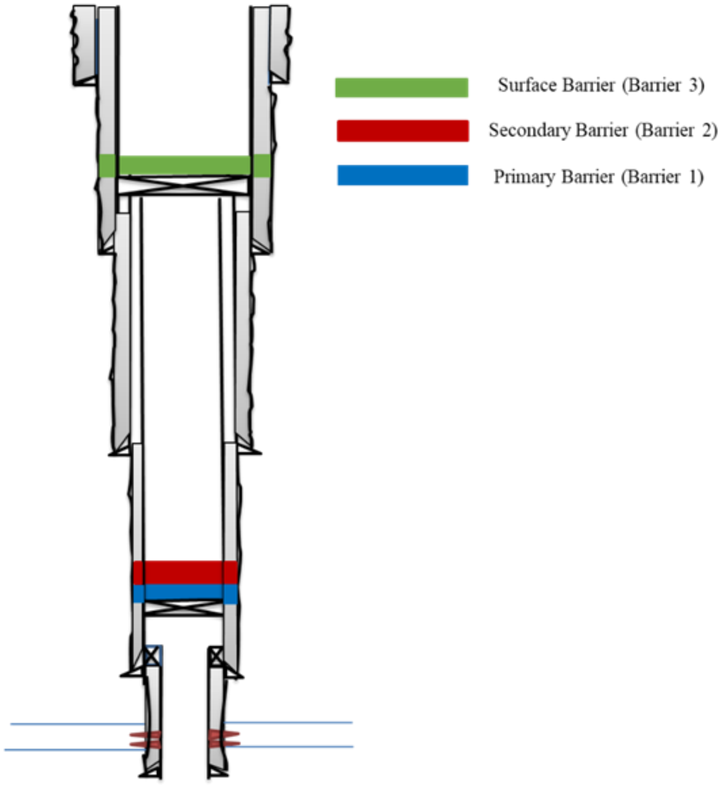

Figure 3. Well barrier schematic (Ford et al. 2017)

This figure includes primary and secondary barriers, as well as the open hole to surface barrier.

1.1.4. Length requirements for well barrier elements

The length requirement for an external well barrier element (WBE) is 50 m with formation integrity at the base of the interval. However, if the casing cement is verified by logging, only a minimum of 30 m interval with acceptable bonding is required for the external WBE. For an internal WBE, the length requirement is 50 m if set on a mechanical plug/cement as a foundation. In addition, it is important that the internal WBE is positioned over the entire interval where there is a verified external WBE (NORSOK Standard D-010, 2013).

Table 1. Minimum cement plug length (NORSOK Standard D-010, 2013).

Open hole cement plugs	The length requirement for open cement plugs is 100 m MD with minimum 50 m MD above source of inflow/leakage point.
Cased hole cement plugs	The length requirement for cased hole cement plugs is 50 m MD if the plug is set on a mechanical/cement plug as foundation. In other cases, the length shall be 100 m MD.
Open hole to surface plug	The length requirement for open hole to surface plug is 50 m MD if set on a mechanical plug. In other cases, the length shall be 100 m MD.

1.1.5. Verification of well barriers

It is important to verify that the barriers meet the requirements as described earlier, to confirm their integrity and position. To do this, the well barriers must be designed such that it is possible to verify their performance (PSA, 2017).

The integrity of a well barrier element (WBE) shall, according to NORSOK Standard D-010 (2013), be verified by pressure testing or other specified methods. If the condition of any WBE has changed or if there is a change in loads, then a re-verification is necessary. The position of cement plug, i.e. internal well barrier, shall be verified by tagging. Cased hole cement plugs shall be verified by tagging and pressure test. While as for open hole cement plugs, pressure testing is not conducted, as this may result in formation fractures (NORSOK Standard D-010, 2013).

For the external well barrier (casing cement), a formation integrity test is used to verified it's sealing ability. The length of the casing cement shall be verified by bonding logs or a 100 % displacement efficiency (based on records of pumped volume vs. returns). The external well barrier may also be verified by old logs, if available (NORSOK Standard D-010, 2013).

1.2. Prescriptive P&A requirements vs. risk-based P&A requirements

The NORSOK D-010 Standards consist of requirements and guidelines on how to perform P&A operations. If the operator uses a recommended solution from NORSOK Standard D-010, then the functional requirement is considered fulfilled. Other solutions than presented in the guidelines may also be used if the operator could verify and document that the chosen solution fulfils the regulatory functional requirement. However, in practice, these requirements are prescriptive. The term prescriptive means that as long as you are subsequent to certain regulations, then and only then, it is acceptable. The reason for this may be that the NORSOK Standard D-010 is written quite strict, e.g. using words as "shall" instead of "should". This is clear from the previous chapter regarding requirements for P&A, where the term "shall" is frequently used. Another reason why the requirements are in practice prescriptive, may have to do with the fact that using other solutions would require verification and documentation. In practice it becomes "easier" to just do it the way that it says in the guidelines, as this is considered sufficient by the government.

However, there are some unfavourable factors to consider if only using prescriptive P&A requirements. An important aspect here is the challenge related to accepting new and other solutions for well barrier elements and designs in P&A operations. It would be unfortunate if an alternative solution would be rejected due to one requirement, missing out on something that could have been a better solution compared to today's technology. This would also be damaging for innovation leading to lower costs for P&A. In addition, if a well could be abandoned using easier solutions such as e.g. shorter plug length, and still be in the safe region, this could be valuable for the industry. However, with today's prescriptive requirements this would not be acceptable. Furthermore, the requirements do not consider the differences between wells. Having the same requirements for different wells are expensive, and since different wells would have various flow potential, a differentiation between wells would allow for cost savings where quality is maintained. Having a risk-based approach for P&A would make it easier to differentiate between different types of wells in the regulations.

Since the requirements are prescriptive, they have a huge influence in how operators perform the P&A operations. According to Eshraghi (2013), the average time-duration for well abandonment increased significantly around year 2004, from approximately 16 days to 35 days, due to new requirements in NORSOK Standard D-010, published in 2003. This would imply that the new requirements became stricter than before. As time means money, the new requirements had a major impact on costs for P&A. Are these requirements necessary to ensure sufficient quality, or could these requirements be too strict?

To cope with these challenges, it would be beneficial to use risk-based requirements. If one could measure the quality, with respect to leakage risk (probability and rate), it would be easier to compare the different P&A solutions with each other. Then one could set a risk acceptance criterion to use as requirement for P&A. Having this risk acceptance criteria would make it easier to also accept new solutions in the future. In addition, other design parameters and easier solutions for P&A could be accepted if these were considered safe enough. This could then reduce the time and costs associated with P&A. Supplementary, having this risk-based regulation could increase the quality of P&A.

Though, one should include the ALARP principle when establishing this risk acceptance criterion. The ALARP principle states that the risk should be reduced to a level that is As Low As Reasonably Practicable. This means that if there exist a safety measure that can reduce risk, it shall be implemented as a rule, unless it can be shown that the costs are in gross disproportion to the benefits gained (Aven, 2015).

Today, the NORSOK Standards D-010 does not accommodate that P&A can be performed using a risk-based approach, and still maintain the PSA regulations. Traditionally, risk has not been researched immensely in this industry, and risk analysis is viewed to as challenging. This may also be one of the reasons why the requirements today are prescriptive. In recent years, the industry is starting to realize that a risk-based approach would benefit the industry both environmentally and economically. The focus has shifted, and this is a good step towards faster, better and cheaper P&A. This also shows why performing a risk assessment of P&A wells is important, as this would provide valuable knowledge to the industry.

2. Natural seepage to the seabed

Seepage to the seabed means that liquids and gases leaks through the seabed and into the marine environment. According to Judd and Hovland (2007), the seabed fluid flow affects seabed morphology (shape of seabed), benthic ecology (organisms that lives on the seabed) and the mineralisation. Crude oil spills into the marine environment can cause serious environmental pollution. However, the environmental pollution can also be a result of natural seepage to the seabed. In this chapter, the natural seepage to the seabed is discussed, including how it occurs, features indicating seabed flow, and some data. In addition, the natural seepage is also discussed in relation to leakages in P&A wells.

Factors that can lead to natural seepage to the seabed (Judd and Hovland, 2007):

- If there exist a migration pathway available, buoyant fluids can then migrate to the surface. This includes the following situations:
  - ➔ Flow along discontinuities, including fractures and faults.
  - ➔ Flow through permeable formations, given that the pressure gradients overcome the capillary pressure.
  - ➔ Gas passing through fine-grained ("impermeable") formation by propagating fractures and voids. E.g. gas chimneys. This does not apply to liquids.
- Pore fluid trapped inside sediments can reduce the shear strength and bulk density of the formation, leading to increased mobility.
- Movement of formation (mobile formations). Fluids enable masses to become mobile.
- Accumulation of fluid resulting in pressure build-up can lead to migration of fluid to the seabed.
- External factors may also cause fluid to rise towards the surface. E.g. due to melting of ice or natural disasters as earthquakes.

When it comes to features indicating fluid and gas flow, biological activity and free gas bubbles are two indications of this. Seepage of fluid and/or gases forms features as seeps, pockmarks and mud diapirs on the seabed. Vertical seepage of gas is also detected by seismic tools showing gas chimneys. These features have been used by the oil and gas industry when searching for hydrocarbon bearing reservoirs as they are good evidence of oil and gas (Judd and Hovland, 2007).

According to Kvenvolden and Cooper (2003), the annual natural seepage of crude oil to the marine environment is estimated to be between 200 000 and 2 000 000 tonnes, globally. The most likely estimate on a global basis is at 600 000 tonnes (180 million gallons) of crude oil. This is about 47 % of all the crude oil entering the marine environment, while the rest is manmade. One can ask oneself whether accidental hydrocarbon spills are of big concern as almost half of the pollution comes from natural seepage to the seabed. However, the rate of crude oil entering the marine environment differs between them. Manmade oil spills have often a much higher flow rate. For natural seepage to the seabed, the flow is at a very low rate. This gives the organisms in the nearby environment time to adapt into the new conditions (Woods Hole Oceanographic Institution, 2014). For wells that have been permanently plugged and abandoned, the leakage rate would most likely also be low. The marine environment would therefore handle a leak from plugged wells much better. However, there are also other aspects to consider, besides flow rate, which affects how much leakage the marine environment can handle. This includes sea currents, wave-activity, temperature, weather conditions, and the presence of oil eating organisms (Johnsen, 2016). This would entail that some areas would handle pollution better than other areas.

The gas which seepage to the seabed has been sampled and analysed. The result from this analysis is that this gas mainly consists of methane. Some methane also seepages all the way up to the earth’s surface. This is mostly the case in shallow waters. Contributions to atmospheric methane by natural seepage may be important with respect to global climate changes (Judd and Hovland, 2007). However, according to Judd and Hovland (2007), several reviews states that the oceans are a minor source of atmospheric methane. Nevertheless, these reviews are based on thin evidence, and Judd and Hovland (2007) says in their book “Seabed fluid flow”, that natural methane sources from the seabed/ocean is not as insignificant as some authors would have us to believe. Methane is a greenhouse gas more devastating to the climate than carbon dioxide, due to absorbing heat more effectively. Over a time period of two decades, methane has an 86 times greater potential for global warming than carbon dioxide (Howarth, 2015). Methane emissions to the atmosphere would also occur for abandoned wells in the shallow waters. In a study performed by Vielstädte et al. (2017), the scientists found out that 42 % of the methane emissions from abandoned wells in the shallow water, reached the atmosphere.

However, seabed fluid flow is not only a bad thing, it provides resources (as methane and metals) and have acted as guide to the petroleum industry (as discussed earlier). In addition, there is evidence of a link between seabed fluid flow and biological productivity, as two major petroleum provinces in the North Sea has also been good fishing grounds (Judd and Hovland, 2007).

Natural seepage is considered as long-term or permanent leakages. However, leaks can also be repaired by the nature itself. Organisms can over time settle around the area of the leak, and thereby seal for further leakage (Johnsen, 2016). This would apply to both natural seeps and P&A wells.

2.1. Estimating the natural seepage rate (based on available data)

According to the book "Oil in the Sea: Inputs, Fates and Effects", developed by the National Research Council Committee in 2003, it was estimated that approximately 41 million gallons of oil seeps into the Gulf of Mexico every year. In addition, a satellite survey showed at least 600 natural oil seeps in the Gulf of Mexico (NASA/Goddard Space Flight Center, 2000). The leakage rate of oil per seep is then calculated to be $8{,}2 * 10^{-3}$ litres/s.

However, this thesis will focus mainly on the methane flux (gas leaks) from abandoned wells, and it is therefore interesting to estimate the methane flux from natural seeps as well. Weber et al. estimated in 2014 the amount of methane flux from the seabed in a 6000 km^2 region in the northern Gulf of Mexico. From 357 natural seeps in this region, the total methane emission was estimated to be between 0,0013 and 0,16 Tg/year (i.e. from 0,06 m^3/s to 7,08 m^3/s, using methane density of 0,668 kg/m^3, at 1 atm and 20ºC). Further, one can calculate the average methane flux from each seep at $1{,}1 * 10^{-2}$ m^3/s.

3. Review of available data on well leakage statistics

Today, if a well has been permanently plugged according to regulations, then further monitoring of the well is not required. Available leakage data for abandoned wells are therefore scarce. Due to this, some data represents integrity failure instead. Following leakage statistics and integrity failure data from North America, UK and Norway are described.

3.1. North America

The number of abandoned wells in the U.S is estimated at 3 million or more (Brandt et al. 2014). This number is highly uncertain due to lack of public records of the oldest wells. In Pennsylvania, the number of abandoned wells is estimated to be between 470 000 – 750 000 (Kang et al. 2014). In this study, performed by Kang et al. (2014), the methane emissions from these wells were estimated to represent 4-7 % of the total methane emissions in Pennsylvania. In addition, the mean methane flow rate for the wells tested were 0,27 kg/well/day (Kang et al. 2014). If using the methane density of 0,668 kg/m^3 (at 1 atm and 20ºC), then the leakage rate becomes 4,7 * 10^{-6} m^3/s. However, a high number of wells in both Pennsylvania and the rest of North America are orphaned, and these wells would therefore have a higher likelihood of leakage.

In a paper presented by Davies et al. (2014), it is shown that the percentage of wells having barrier failure or integrity failure, ranges between 1,9 % to 75 %. The dataset varies to a great extend due to differences in the number of wells examined, their age and their designs. See data in table 2.

Table 2. Percentage of failure rates of wells in North America (Davies et al. 2014).

Location	**Percentage of wells with barrier failure or well integrity failure**	**Wells tested**	**Source**
Canada	22 %	435	Erno and Schmitz (1996)
USA	75 %	50	Chilingar and Endres (2005)
Canada (Alberta)	4,6 %	316 439	Watson and Bachu (2009)
USA	2,6 %	3533	Considine et al. (2013)
USA	3,4 %	6466	Vidic et al. (2013)
USA	1,9 %	32 678	Ingraffea et al. (2014)

According to a different study, performed by US Minerals Management Service in 2004, a total of 6 650 out of 14 927 active wells in the Gulf of Mexico (GOM) had sustained annular pressure. An annular pressure buildup may result in lack of zonal isolation. This means that 45 % of the wells in the GOM has integrity issues, that may result in HC emissions (Feather, 2011).

3.2. UK

According to a paper written by Davies et al. in 2014, there had been none reported pollution with inactive abandoned wells, and only a small number of pollution incidents related to active wells in the UK sector. This would indicate that pollution is not a common event. However, permanently abandoned wells have not been monitored as this is not a requirement. In addition, pollution of methane in small amounts is difficult to detect, supplying to an underestimation of the actual number (Davies et al., 2014).

In 2016, Boothroyd et al. conducted a study of 102 decommissioned onshore wells in the UK. According to Boothroyd et al. (2016), this study showed that 30 % of the wells were leaking methane (CH_4). This percentage may be large, but the amount of methane released from each well were less than what a dairy cow produces. The emissions were estimated to be 364 ± 677 kg CO_{2eq}/well/year, while a dairy cow produces 2944 kg CO_{2eq}/head/year. The fugitive emissions of a well not decommissioned, were estimated to a much higher number, at 8604 kg CO_{2eq}/well/year (Boothroyd et al. 2016).

Since leakage data regarding abandoned wells are limited, it is possible to study data regarding integrity failures also. According to the SPE Forum (2009), a total of 1600 out of 4700 wells had integrity failures in the UK. I.e. 34% of the wells had barrier issues.

3.3. Norway

For plugged and abandoned wells on the NCS, the only data available are from NPD fact pages. Arild et al. (2017) have processed these data to give a statistical overview of the P&A wells on the NCS. They identified 334 wells and studied the age of abandonment for each of the wells. As a result, figure 4 shows numbers of P&A wells on the NCS for each age of abandonment. The age is calculated to year 2016, i.e. if a well is plugged and abandoned in 2014, then the P&A well is at age 2 (Arild et al. 2017).

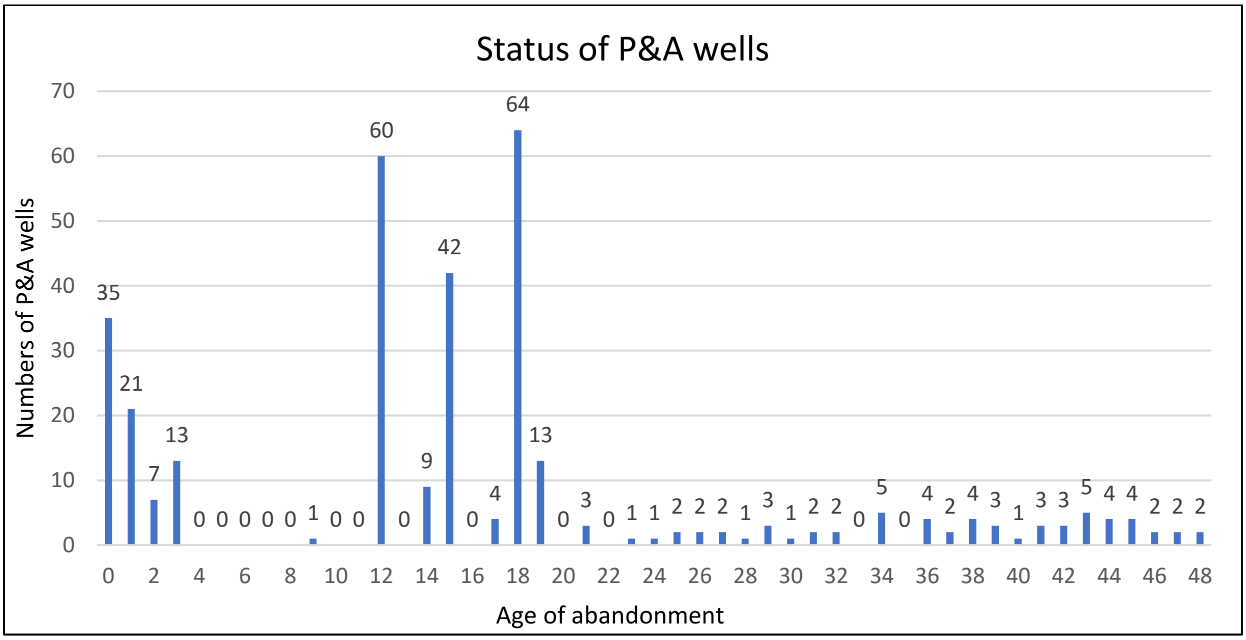

Figure 4. Status of P&A wells on the NCS (Arild et al. 2017).

None of these wells have been reported leaking (Arild et al. 2017). These data are therefore referred to as censored data. Censored data is data of systems or components that has not failed when the "recording time" or study is finished, i.e. we know it survived to a certain point in time, but nothing more (Aven, 1992). This is also referred to as right censored data, while left censored data means that the data is below a certain value, but it is unknown by how much (Støtvig, 2014). Censored data is therefore a type of missing data. The opposite of censored data is recorded failures, which are data where you actually know how long it has survived/lived (Aven, 1992).

Since the data regarding leakage in plugged and abandoned wells are scarce, it is interesting to look at wells with integrity failure as a comparison. The Petroleum Safety Authority (PSA) conducted a survey of 406 wells from 12 offshore facilities in Norway. According to Vignes and Aadnøy (2010), this study showed that 18 % of these wells had integrity failure, issues or uncertainties.

3.4. Overview – failure and leakage statistics

Summarized, by going through the failure and leakage statistics for North America, UK and Norway, it seems that the probability of failure is highest for wells in North America. In addition, the probability of failure/leakage is smaller for UK wells, and even smaller for the wells in Norway. Figure 5 represents the percentage of wells with integrity failures for North America (GOM), UK (North Sea) and Norway (North Sea), respectively. This figure therefore gives a good representation of the conclusion after addressing the data earlier in this chapter.

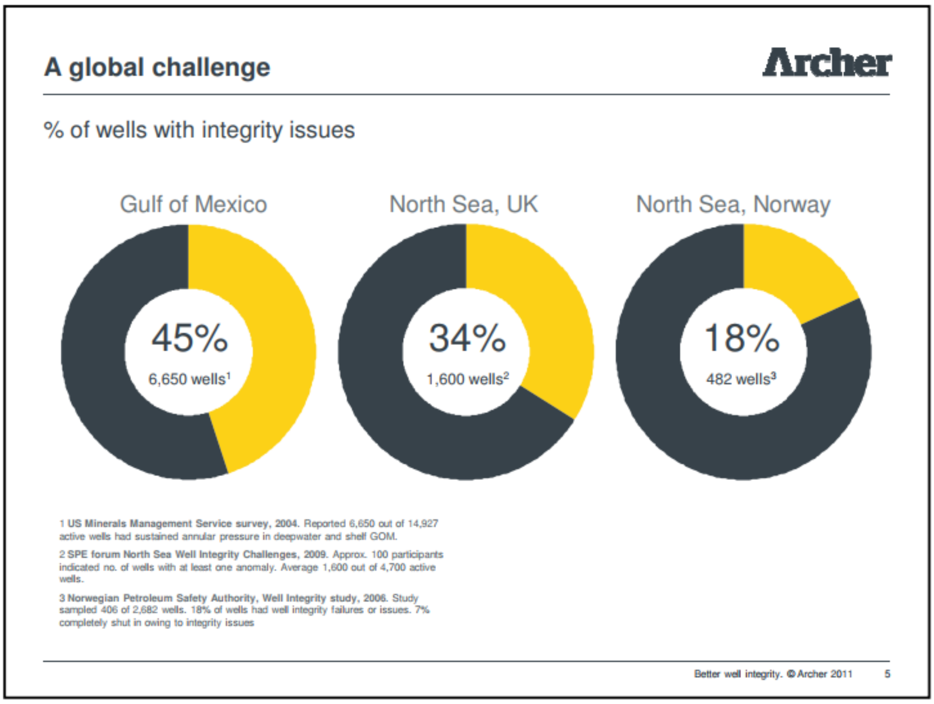

Figure 5. Percentage of wells with integrity issues for GOM, UK and Norway (Feather, 2011).

The number of wells in North America and the GOM are much higher compared to the number of wells in UK and Norway. Many of these wells were also drilled in the early days, before proper regulations were introduced (Feather, 2011). In addition, a larger number of the wells in North America are HPHT wells, which imposes a higher risk of leakage. A great majority of the wells in North America are also orphaned. These wells have been drilled and later abandoned by companies who no longer exists or have been taken over or merged. Orphaned wells are a problem for the government as there a high uncertainty related to these wells. Hence, all this together, will increase the probability of failure for the wells in North

America and the GOM. This also explains the high percentage related to integrity failure for wells in the GOM, presented in figure 5.

In Norway, the percentage would be much lower. This is because most of the wells here are LPLT, which has a lower risk of leakage. In addition, these wells are newer, which would imply that these are safer due to newer materials, stricter regulations and better knowledge (Jackson, 2014). This may explain why there has been none reported leakages in P&A wells on the NCS. However, the probability of failure/leakage in UK wells would be higher than Norway, as the regulations in UK are not as strict. Also, up to 53 % of the wells in UK are orphaned, and the liability of these wells with respect to leakage, is unclear (Davies et al. 2014). However, this is not an issue for the wells in Norway, as there are no orphaned wells on the NCS. Due to the reasons above, it is natural that the percentage showing integrity failure for UK is higher than for Norway.

4. Definition of risk

An important part of this thesis is related to risk and how to understand risk. It is therefore important to discuss how risk is defined and fully understand what risk includes. Risk is defined in many ways, depending on which source. However, it is a misconception that risk equals to expected value. This is not a good way to reflect risk in general, as risk is much more than expected values. Risk includes consequences, uncertainties and probabilities. Hence, when facing risk there will be consequences (positive or negative, severe and not severe), and there are also uncertainties related to these consequences (Aven, 2015). A tool used to explain these uncertainties, is probability. It is also important to make an assessment of the background knowledge in which the probabilities are based on. This means looking at the strength of models and data used, and whether the assumptions are reasonable (Aven, 2015).

NORSOK Standard D-010 (2013), defines risk as *"combination of the probability of harm and the severity of that harm".*

When performing a risk analysis, the objective is to present an informative risk picture that explains the risk associated with a certain situation. Further, decision makers use risk analyses to support in decision-makings (Aven, 2015).

In this thesis, the aim is to assess the leakage risk in P&A wells. This includes analysing the probability of barrier failure and leakage rate. Hence, the consequence here is referred to as leakage rate (given that the barrier system has already failed). In addition, there will be uncertainties related to these leakage rates.

5. Acceptable leakage rate

If the objective is to use a risk-based regulation for P&A operations, then an acceptable leakage rate criterion must be established. This chapter discuss how the acceptable leakage rate criterion should be constructed, and different approaches in how to define a number to act as acceptable leakage rate.

According to ISO (2009), risk criteria is defined as *"terms of reference against which the significance of a risk is evaluated"*. In other words, risk criteria are used to determine whether a specified level of risk is acceptable (tolerable) or safe enough. Risk acceptance criteria are specified by a decision-maker, telling us the amount of risk tolerated, as an elimination of all risk is impossible. The essence of having risk acceptance criteria is to help in a go or no-go decision. In addition, the risk acceptance criteria should allow for optimization.

Setting a clear line for what is acceptable or not is difficult and quite impracticable. Instead, different ranges of acceptable levels should be implemented (DNV GL, 2015). This is shown in the figure 6.

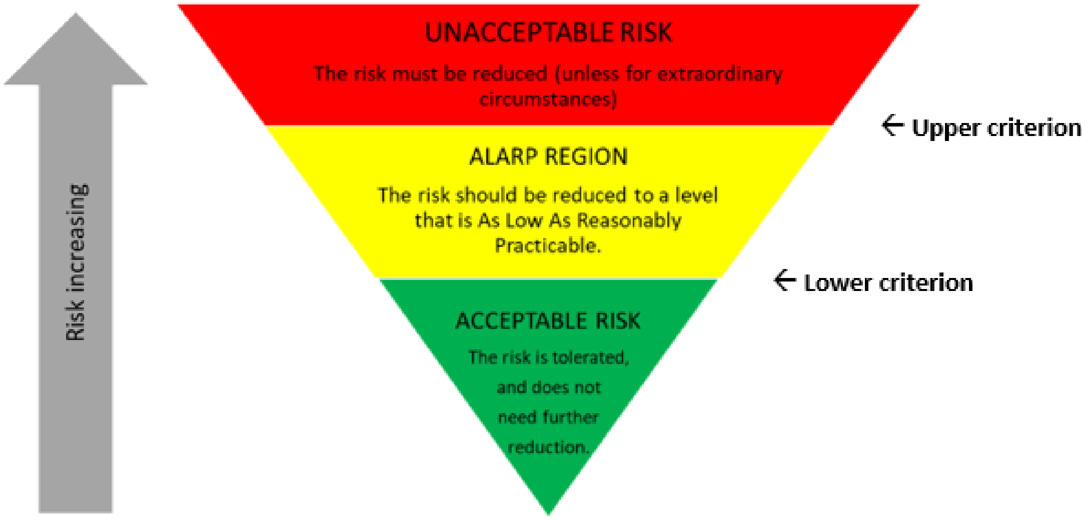

Figure 6. Region framework for acceptable risk criteria (DNV GL, 2015).

The bottom level implies that the risk is acceptable or negligible, and no further actions is necessary or even possible to reduce further risk. The middle level is a level where the ALARP principle should be implemented, as described earlier in this thesis. The risk should here be reduced to a level that is as low as reasonably practicable, taking into account the benefit gained by this risk reduction. If the potential risk is measured to be in this region, the risk should be reduced further, or it should be documented that the costs are in gross disproportion to the benefit gained (Aven, 2015). The top level shows a level of unacceptable risk, where the risk must be reduced (excluding extraordinary circumstances). This theory regarding ranges of acceptable criteria could be beneficial to use also for leakage rate for permanently plugged and abandoned wells. By using this methodology, one includes the ALARP principle as desired and discussed earlier in this thesis.

After concluding that it would be beneficial to use ranges of acceptance instead of an exact line separating acceptable and not acceptable, it is time to look at leakage rate numbers to get an idea of how to divide them into different ranges. How should one proceed in order to find the acceptable leakage rate with respect to lower and upper criterion (from figure 6)? What should be our terms of reference, or reference frame? What is safe enough with respect to leakage rate for P&A wells? Different approaches to define an acceptable leakage rate is addressed in chapter 5.1.

When assessing risk in P&A wells, it could also be beneficial to use a risk matrix, as displayed in figure 7. This is a way to differentiate between types of wells, as these would have various leakage risk.

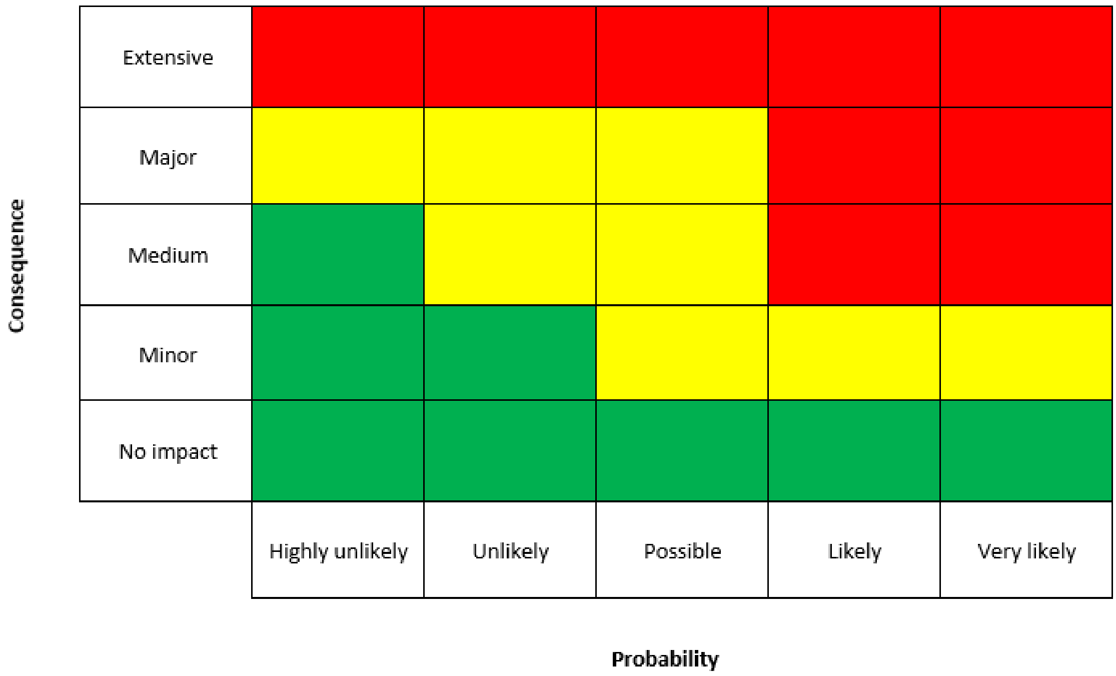

Figure 7. Risk Matrix (Jordan et al. 2016)

If the probability of leakage is high, and the associated consequence (leakage rate) is severe, then either the risk is not acceptable (red zone), or the ALARP principle (yellow zone) should be implemented. Then, measures should be done to reduce the risk, which could in practice mean stricter P&A requirements for these wells. One example may be to use a longer plug length to ensure adequate safety for these types of wells. On the other hand, if the probability is low and the associated consequence is minor, then the risk is acceptable. This would imply that these types of wells would not require as strict requirements as the others.

Lastly, it is important to be aware of that there is a close relationship between risk acceptance criteria and ethics (Vanem, 2012). In ethics we learn about what is right and wrong, or good and bad. Simultaneously, when defining risk acceptance criteria, one is saying something about what is acceptable or not. According to Vanem (2012), a risk acceptance criterion should have one or several ethical theories as basis. This is to justify the chosen criteria towards the public. For example, the ALARP principle has an underlying ethics saying that it is a moral duty to keep risk as low as reasonably practicable. In addition, this principle has a basis in the theory of utilitarianism (Vanem, 2012). This ethical theory states that one should choose the action which has the maximum utility.

5.1. Different approaches to define an acceptable leakage rate

According to Norwegian Oil & Gas (2017), the objective should be to identify a rate were a release will not result in unacceptable consequences. The leak rate should therefore be as low as possible. Following, different approaches to define the acceptable leakage rate and potential terms of reference to get a good indication of what could be acceptable and not for abandoned wells. In addition, the probability of leakage should be included in this risk criteria. However, this is rather addressed in the case-study later in this thesis. The focus on this chapter is therefore only about the consequence (leakage rate), given a leakage has occurred.

5.1.1. Use API Recommended Practice 14B

According to API Recommended Practice 14B (2014), the maximum allowable leakage rate through a closed subsurface safety valve system is 0,4 litres of liquid per minute (6,7 * 10^{-3} l/s) and 0,42 m^3/min (7,0 * 10^{-3} m^3/s) for gas leaks. This practice could also be implemented with respect to acceptable leakage rate for plugged and abandoned wells.

5.1.2. Environmental risk acceptance criteria

This risk acceptance criterion is based on an environmental aspect. According to DNV GL (2016), one method is to study the effect of HC release to a certain geological area or environment. Every geological area consists of Valued Ecosystem Components (VEC's), which are elements of the environment that has scientific, economic, social or cultural significance. Further, one is looking at the sustainability of these VEC's in that area. If the current ecosystem in that area could live with the amount of daily discharges of HC, then it should be acceptable. This acceptance criterion therefore depends on the amount of HC the VEC system in that area could tolerate (DNV GL, 2016).

Another method is to use the natural seepage rate directly as acceptance criteria. As discussed earlier, the rate of natural seepage to the seabed is quite low, giving the marine environment time to adapt properly. This implies that if the leakage rate from an abandoned well is at the same rate (or below) the natural seepage rate, then it should be considered acceptable. The next step is then to estimate the natural seepage rate from accessible data.

As shown in chapter 2, the average methane flux per seep were estimated at 1,1 * 10^{-2} m^3/s. This was based on a survey of natural seeps in the Gulf of Mexico, performed by Weber et al. in 2014. By using this number as maximum allowable leakage rate for plugged wells, it would mean that an abandoned well could have a leakage rate up to 1,1 * 10^{-2} m^3/s, and still be acceptable.

5.1.3. Consistency between wells (NORSOK D-010 req.)

According to Godøy et al. (2015), operators could define a base case, indicating the highest allowed gas mass flow rate, also referred to as Upper Acceptable Case (UAC). Then, the operators can compare the gas mass flow of one well with the UAC, helping them with their decision making with respect to P&A strategy. If the gas mass flow of this well is higher than the UAC, then the P&A strategy needs to be redefined. The UAC's gas mass flow rate was set at 1 kg/year (Godøy et al. 2015). This is equivalent to 4,8 * 10^{-8} m^3/s, using the density of methane at 0,668 kg/m^3 (20ºC and 1 atm). This number were obtained when studying the gas mass flow rate for a HPHT well, with permeability 0,1 µD and 30 m. annulus cement (Godøy et al. 2015). One can also estimate this UAC number by using the leakage rate calculator (which will be explained later in this thesis). In this leakage rate calculator, one can use the parameters related to a HPHT well (worst case) to assess the leakage rate for this well abandoned according to the regulations and use this as a basis for the acceptable leakage rate. This method is based on the theory that is should be consistency between wells.

Since a well abandoned according to today's regulations is seen as an acceptable way of performing P&A operation, it can be interesting to look at leakage data from abandoned wells. In UK, 102 decommissioned onshore wells were tested for methane leakage. The maximum leakage rate from these decommissioned wells in UK (Boothroyd et al., 2016) was estimated at 1041 kg CO_{2eq}/well/year. According to calculations (see appendix), this is equivalent to 7,8 * 10^{-7} m^3/s/well, measured in CH_4. Also, in Pennsylvania (USA), a study of the flow rate in abandoned wells were conducted. According to this study performed by Kang et al. (2014), the mean methane flow rate for these abandoned wells were 4,7 * 10^{-6} m^3/s/well. In Norway, there is no leakage data available, as there has not been reported any leaks in relations to abandoned wells.

5.1.4. Use other pollutions activities as index for acceptable leakage rate

Another suggestion is to compare the data with other pollutions activities and industries. One example is to use grazing rates. For lowland agriculture in the UK, typical grazing rates are 3 cows or 21 sheep per hectare (Boothroyd et al. 2016). Then, one could use the rate of pollution emitted from these animals within one hectare and use this same rate as a criterion. Then, instead of looking at pollution from each well, one can measure the pollution within areas of one hectare. According to Boothroyd et al. (2016), one dairy cow emits 2944 kg CO_2/head/year. Following the calculations in the appendix, gives a leakage rate of 2,2 * 10^{-6} m^3/head/s, measured in methane. Multiplying this number with 3, gives the amount of pollution emitted in an area of 1 hectare; 6,6 * 10^{-6} m^3/s. Then, if using this as acceptance criteria, leaks from wells within an area of 1 hectare can have a total leakage rate of 6,6 * 10^{-6} m^3/s and be considered acceptable.

Instead of looking at emissions in an area, one could use the emission from a cow as an acceptable leakage rate. I.e. the leakage should be less than 2,2 * 10^{-6} m^3/min. If using this as acceptable leakage rate, then abandoned wells should leak less than (or equal) to this number.

Another suggestion is to use pollution rates from other industries as acceptable rate. One example is the power plant industry. The Center for Global Development (2007) has rated the top 100 of the highest CO_2-emitting power plants in the United States. The Scherer power plant has the highest emission, with a yearly emission of 25 300 000 tons of CO_2 (Center for Global Development, 2007). Following the calculations in the appendix gives a leakage rate of 19 m^3/plant/s (measured in CH_4). This could then be used as acceptance criteria for a hole petroleum field.

5.1.5. Carbon tax and emission trading system

Instead of having a maximum allowable leakage rate, the government could use carbon tax in combination with an emission trading system to ensure low emissions. In a tax-based system one is charged for all emissions and there is no cap on how much one can emit. To set a cap on the emissions, one can include a trading system where one is required to have a permit to emit greenhouse gases. This is called a carbon credit, which represents the right to emit one tonne of carbon dioxide or the mass of another greenhouse gas (equivalent to one tonne of CO_2) into the environment (Pannell, 2011). Companies are yearly given a certain amount of carbon credits, and if they manage to reduce the emissions, they could sell the rest of their carbon credits in the market. This combination of carbon tax and trading system is a way to reduce emissions, as this makes it profitable for companies who are able to reduce their emissions. A suggestion is therefore to use this for P&A wells also, instead of having a maximum allowable leakage rate.

5.1.6. Using lifetime and reliability

This method has an underlying theory saying that the risk becomes unacceptable at the maximum time a well can remain in its current status. Consider a well that has just been plugged and abandoned, and it is not leaking, for how long will it remain in this zero-leakage status? One could set a minimum time the well has to remain in this zero-leakage status and use this as criteria for P&A wells. If say, the minimum time criteria were set at 500 years. Then, one could calculate the reliability (the ability of the system to function as it should) of an abandoned well to remain in this zero-leakage status for that time-period. Only if the calculations showed that the well would remain in this zero-leakage status for 500 years, the associated P&A solution would be acceptable.

5.2. Discussion - best practice to define maximum allowable leakage rate

The first point mentioned in the theory is to use API recommended practice 14b, which states the maximum allowable leakage through a closed subsurface safety valve system. However, there are some problems with using this practice for maximum allowable leakage rate for P&A wells. A leakage through a valve system would be shut-off as soon as it is detected. The leakage would therefore occur only for a short period of time. This is not the case for P&A wells, where one is assuming long-term (permanent) leakage as no one is there to stop it, if not nature itself does (as mentioned in chapter 2). The leakage rate from API recommended practice 14b is therefore too high to be applicable for leakage in abandoned wells.

However, natural seepage to the seabed would in that case fit better for this purpose, as this kind of leakage also has a long-time perspective. Using this as an acceptable leakage rate, would imply that permanently abandoned wells could have the same leakage rate as natural seepage, and still be considered acceptable. The reason for this, as discussed earlier, is that the leakage rate for natural seepage is quite low, giving the marine environment nearby time to adapt into the new conditions. Though, one problem considering this approach then arises. If permanently abandoned wells could leak as much as natural seepage, then this would imply that the total leakage (rate) would be doubled. This would disturb the balance in the earth's carbon cycle. Before the Industrial Revolution, carbon dioxide levels were quite steady due to its natural balance. In addition, it is difficult to do anything about natural seepage to the seabed, precisely because these are natural. Contrary, wells have been disrupted by humans and then it is easier to influence the future leakage risk when these are to be abandoned. So even if the leakage rate for natural seepage is natural, it does not automatically mean that it is acceptable or sustainable that manmade leakages has the same rate. The operators should strive towards reducing the pollution as much as possible. This shows why the ALARP principle is important to include, namely to ensure this.

Additionally, it is observed that the data referring to the leakage rate of natural seepage is quite similar to the API numbers, which were considered too high to be applicable for P&A wells. This is therefore another reason why the acceptable leakage rate for P&A wells should be reduced further and as much as possible.

However, the data available regarding natural seepage to the seabed is scarce, and this would have to be taken into considerations if using this as a maximum allowable leakage rate for P&A wells. I.e. doing more research to strengthen the background knowledge.

Today, a well is considered sufficient abandoned if the operators follows the regulations. This would entail that the leakage rate for these wells is considered acceptable. Therefore, estimating the leakage rate of a worst case well (HPHT well), abandoned according to regulations, could be used as acceptance criteria. This method would reflect todays requirements in terms of leakage rate. Since consistency is key, this method is seen as the recommended solution for leakage criteria in P&A wells

Leakage data from previously abandoned wells could also give a good indication on what could be acceptable or not. As seen in the calculations regarding leakage data of abandoned wells in UK and Pennsylvania, these leakage rates are lowest compared to the other approaches. However, a disadvantage related to using previous leakage data is that these data are scarce, as monitoring of wells has not been a requirement for P&A wells. Hence, these numbers do not necessarily represent the majority of abandoned wells. In addition, since Norway has fewer wells with integrity issues and no reported leaks in P&A wells compared to North America and UK (see chapter 3), it is recommended to use Norway as reference. Even though, none of the P&A wells in Norway have been reported leaking, it is impossible that a well would have zero leakage for eternity. A suggestion is therefore to use the leakage calculator to estimate the average leakage rate of a HPHT well abandoned according to the requirements in NORSOK Standard D-010, and use this as reference in the acceptance criteria.

Regardless of the chosen approach, one would also have to consider other aspects when defining the acceptable leakage rate. One aspect to consider is geological location. For example, wells in shallow waters would have a higher degree of air pollution than deep water wells as discussed earlier in this thesis. In addition, the marine geology would affect the risk of leakage. Some marine environments would have a higher risk of leakage due to depth, pressure, temperature and other geological conditions. Also, different areas have various degree of toleration with respect to pollution in the marine environment. Another aspect to consider is the number of wells within one area, and if this area has natural seeps as well. This would also affect the amount of pollution the marine environment in that area could tolerate. Should one allow for higher pollution rate in some areas, and have stricter regulations in other areas? Should one have a maximum allowable leakage rate for the entire field as well? What if there are multiple fields adjacent to each other? These aspects should be taken into consideration when defining the acceptable leakage rate.

To get an idea of how much pollution should be accepted for an entire field or area, it could be beneficial to study other industries. For example, by considering grazing rates or the power plant industry. Nevertheless, the biggest challenge then is how to compare them properly. Is it even possible to compare or correlate them? Could a petroleum field correlate to a power plant? The differences between power plants and petroleum fields are many. First and foremost, a power plant is on land, while abandoned wells are present below the seabed. This would affect the amount of air pollution. The emission data from power plants studied earlier is very high and it seems difficult to compare it with leakages in abandoned wells. In addition, the emission from power plants would not be permanent, as for abandoned wells.

A suggestion was to use grazing rates and calculate the emissions from cows per hectare. However, the challenge with using this approach is to define the areal. Should one consider the areal of the field? In addition, a leakage in an abandoned well would occur right above the well, while emission from cows would be spread around the hole area (as they move around). Another point is that grazing rates has more to do with feed rather than how much they emit and would therefore not be applicable for abandoned wells. However, it is interesting to see that the emission rate of a cow is similar to the leakage rate of abandoned wells in Pennsylvania. It is also discussed earlier that abandoned wells in the UK emitted less than what a dairy cow produces. The emission from abandoned wells is therefore quite low, as it is less than or the same as one cow emits. This strengthen the idea of using the number from previously abandoned wells as acceptable leakage rate. In addition, when comparing the leakage rate in abandoned wells with cows it gives us an idea of how much leakage one is talking about.

Instead of using a maximum allowable leakage rate, a suggestion is to use carbon tax and trading systems for abandoned wells. This would give the operators incentives to reduce emission if these would result in cost savings. However, a disadvantage related to this method is that it is difficult to define how many years to pay for carbon credits/tax as a leak in abandoned wells would be permanent/long term. Also, if one were to pay this upfront, then this would be challenging for many companies.

The last method suggested was about reliability and setting a criterion of how long a well should not be leaking. However, it would be difficult to detect if a leakage has occurred earlier than the minimum criteria due to no monitoring of wells. In addition, choosing the time period of the well to stay in zero leakage state could be challenging.

5.3. Conclusion – acceptable leakage rate

The objective was to find the best practice for defining the acceptable leakage rate, including lower and upper criterion. The recommendation based on the discussion in previous chapter is as follows:

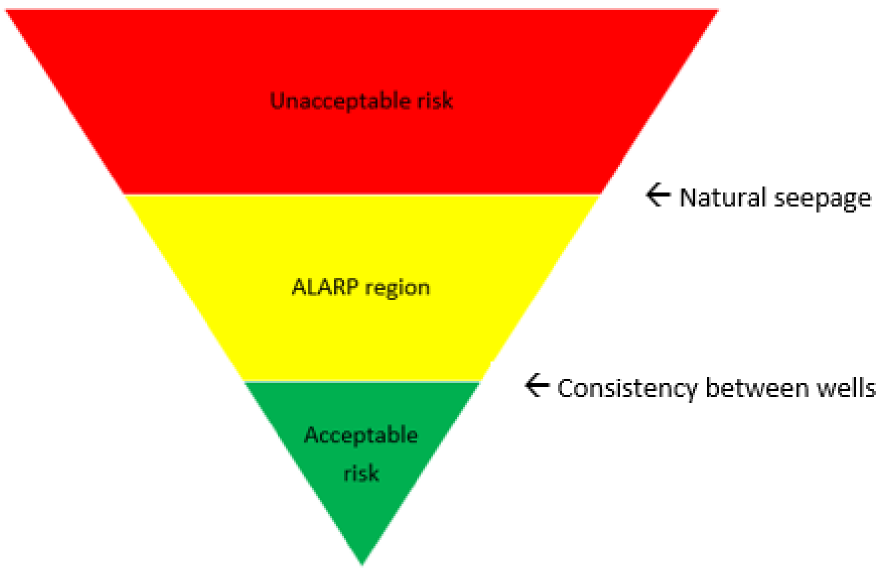

Figure 8. Best practice for defining acceptance criteria for P&A wells.

Using the theory of consistency between wells is seen as best practice as this would replace the regulations we have today. I.e. this is how the requirements today are converted in terms of leakage rate. If the leakage rate is the same or below this number, then no further action should be required. Further, the upper criterion is related to natural seepage to the seabed, indicating that the same leakage rate for abandoned wells should be accepted. However, due to doubling the total leakage when allowing abandoned wells the same leakage as natural seeps, the operators should be required to reduce the leakage rate as much as possible, giving the ALARP region in between.

Today, monitoring of wells after abandonment is not required if the well has been plugged according to regulations. This makes is difficult to detect any leakage from the well in the future. A solution is to require the use of monitoring after well abandonment. If the pollution level is higher than the acceptable leakage rate, then further action is required. Simultaneous, if it can be verified that the leak in an abandoned well does not contain any HC, it could be appropriate to allow leaks higher than the acceptable leakage rate (Norwegian Oil & Gas, 2017). In addition, monitoring after abandonment could be beneficial to use in order to evaluate the leakage rate potential of wells. However, a huge disadvantage related to monitoring is that this method is quite costly. Monitoring of wells is therefore not seen as recommended practice.

In the foregoing discussion chapter, it was mentioned that it would be prudent to have different requirements depending on the well situation. This is where the risk matrix could be useful. For example, it could be beneficial in the requirements to distinguish between reservoirs with high pressure/ temperature- and reservoirs with typical low pressure/temperature conditions. HPHT wells should have stricter requirements due to a higher risk of leakage. If a well has a high flow potential, then the cautionary principle should be considered in a greater extent. This principle states that measures should be taken, or the activity should not be carried out if there is risk associated with the activity, i.e. you should be cautious (Aven, 2015). This is important as the primary focus is to take care of the environment.

If the consequence with respect to environmental leakage is high, then measures should be taken to reduce these possible consequences. Hence, demanding stricter requirements for these types of wells. For wells that would have a low flow potential, it is not as important to include the cautionary principle, as the leakage consequence with respect to the environment is minor. Then, one could rather put more focus into a cost-benefit analysis, where one is comparing benefit and cost. A benefit by using a risk-based approach for P&A is that it then becomes easier to differentiate between these wells in a risk-based requirement.

As mentioned earlier, it is not sufficient to consider only the leakage rate, as the probability of leakage would have a great impact as well. This will be addressed in the case-study (see chapter 8.4). Additionally, there are uncertainties related to the leakage rate, that would have to be taken into consideration.

6. Establishment of methodology for quantification of probabilities

As mentioned earlier, it is not sufficient to consider only the leakage rate, as the probability of leakage would have a great impact as well. Therefore, this chapter focus on establishing a methodology for quantification of the probabilities with respect to leakage in P&A wells.

6.1. Failure Modes and Effects Analysis (FMEA)

To evaluate and assess leakage risk from a P&A well, it could be helpful to use a FMEA (Failure Modes and Effects Analysis). When using this analysis, the system is divided into elements and each of them is studied with respect to failure modes, and probability is assigned for these events. As a result, this gives a systematic overview of critical failures in the system (Aven, 2015).

FMEA for well barrier elements (Arild et.al., 2017):

1. Identification of well barrier element
   - ➔ Identify which and what type of well barrier.
   - ➔ Identify barrier elements within this well barrier. This is done by decomposing the barrier into different elements. Examples: cement plug, casing steel, casing cement and in-situ formation (Arild et al., 2017).
2. Function, operational state. The barrier element functions if it stops oil or gas to migrate both vertically and horizontally (sealing properties).
3. Failure modes. A well barrier fails if hydrocarbons leak through the barrier. Each barrier elements have its own failure modes.
4. Probability of failure and related consequences. Each failure mode is assigned a probability (p_i), and the possible consequences (c_i) related to each failure mode are quantified. The failure probability for well barrier elements is related to time and can therefore be expressed to as “probability of failure within x years”. While the consequences are reflected in terms of “hydrocarbon leakage rate over time”. Probability and associated consequences gives us an understanding of the risk related to a failure mode.

5. Establish a systematic overview of the data given from the FMEA. This would result in a good risk picture of the barrier elements in permanently plugged and abandoned wells.

However, the data required in FMEA regarding P&A wells are both fragmented and limited (Arild et.al. 2017). Therefore, a modelling framework is necessary in order to quantify the probability of leakage in P&A wells.

6.2. Quantifying probabilities using modelling framework

Since the data available are scarce, one should quantify the probabilities using a modelling framework. The idea is then to assess the reliability and life-time of well barrier elements using models. According to Aven (2015), reliability is defined as the ability of a system to function as it should. For P&A wells, it means that the barrier elements seal the hydrocarbons in the well for the period of time planned. When assessing reliability, a common approach is to use lifetime and lifetime distribution. The lifetime distribution shows the possible range of lifetimes as well as the corresponding probability of how likely they are to occur, whether one is studying one component or the whole system.

6.2.1. MLE Method

The maximum likelihood estimation is a method used to model the lifetime distribution and the corresponding failure probability, using data observed. Based on the observations, the MLE method finds the value which maximizes the likelihood function (Hamada et al. 2008). One suggestion is therefore to use this method to quantify the probabilities of leakage in P&A wells. However, as seen in the equation below, the MLE method uses both censored data and recorded failure times.

$$L(\theta) = \prod_{i \in F} f(t_i \mid \theta) * \prod_{i \in S} R(t_i \mid \theta)$$

F = set of failure times, S = set of censored data

6.2.1.1. Example: Estimating probabilities using MLE method (based on NCS data)

As mentioned earlier, the data gathered from NCS on abandoned wells shows only censored data, as none of them has been reported leaking yet (Arild et al. 2017). Since there only exist censored data, the MLE will give $\lambda = 0$. Zero is not a valid value for the rate parameter λ. In such cases, one must conclude that the maximum likelihood estimator does not exist, and the MLE method is therefore a poor approach for these cases.

6.2.2. Bayesian approach

Since there are only censored data available, a Bayesian approach would work better. When using a Bayesian approach, one could also use additional information by introducing the prior information. The prior information is available from e.g. experts, models etc.

The objective is to find the posterior predictive distribution for the barrier lifetime. Then, one could use this to calculate the probability of barrier failure. To do this, the starting point is to use Bayes theorem (Hamada et al. 2008):

$$P\ (time\ to\ leak \mid data) = \frac{P\ (data \mid time\ to\ leak) * P\ (time\ to\ leak)}{P\ (data)}$$

Where;

P (time to leak | data) is the posterior distribution.

P (data | time to leak) represents the lifetime data available.

P (time to leak) is the prior information, available from experts, models etc.

Using a Bayesian approach to find the posterior predictive distribution for the barrier lifetime can be accomplished by following these next 4 steps (Arild et al. 2017):

Step 1: Choose a likelihood distribution. Commonly used likelihood models are Weibull, exponential, Gamma and lognormal distribution.

Step 2: Establish the prior distribution. This is a subjective probability distribution of p before observation. Say that P(A) = 0.6, then subjective probability means that the assessor compares the uncertainty/degree of belief of an event "A" to occur with drawing a red ball out of an urn that comprises 10 balls where 6 are red (Aven, 2015). I.e. subjective probability is a numerical measurement of probability, reflecting one's belief of the likelihood of an event "A" to occur. The prior information is available from experts, models and empirical data, and all relevant information should be included in the prior distribution. Commonly used prior distributions are uniform and triangular distributions.

Step 3: Calculate the posterior distribution for the parameters in step 2 using the Bayes formula. The posterior distribution is a subjective probability distribution of p given data observed. This is done by using the Monte Carlo simulation to combine different distributions from the likelihood and the prior distribution.

Step 4: A lifetime distribution is then accomplished by computing the posterior predictive distribution using this following approach:

- ➔ First, gather the distribution parameters from the posterior distribution.
- ➔ Then, use these sampled parameters to assemble failure times from the lifetime distribution.
- ➔ Repeat these two sections until the amount of sampled failure times reaches an adequate representation of the posterior predictive distribution.

After performing the Bayesian approach and finding the posterior predictive distribution, one can easily calculate the probability of failure within a given period of time.

6.2.2.1. Example: Estimating probabilities using a Bayesian approach (based on data from NCS)

The most commonly used lifetime distribution is the Weibull distribution, due to its versatility. This particular likelihood distribution is therefore chosen for this purpose as well. The shape value β is known at 1.5 (>1), indicating that failure increases with time (Arild et al. 2017). This is because, over time, the reservoir pressure in the well will increase, cement will deteriorate, and the steel will undergo corrosion. All this together will increase the likelihood of leakage over time.

On the other hand, the scale parameter is unknown. However, it is assumed that the scale parameter follows a uniform distribution from zero to 1000 years (Arild et al. 2017). With these assumptions as basis, the prior predicted distribution can be calculated as shown in figure 9 (a).

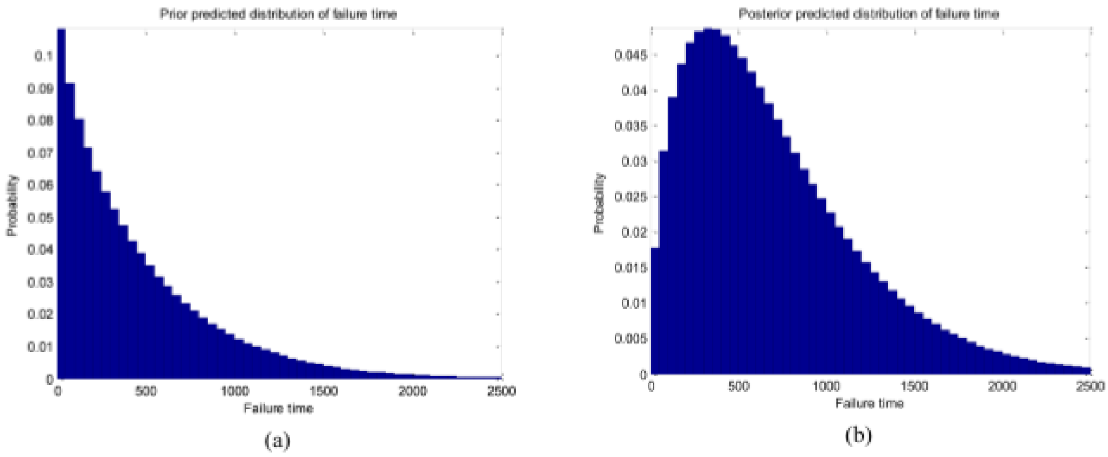

Figure 9. Prior predicted distribution and the posterior predicted distribution of failure time (Arild et al. 2017).

To update our prior belief about the scale parameter, the data from the NCS (334 censored lifetime data) is applied. Further, Bayes formula is used to calculate the posterior predicted distribution (as shown in figure 9 (b)). Due to the censored observations from the NCS, the failure times has been shifted to the right, indicating that an early failure is highly unlikely. The probability of leakage within 100 years is then estimated at 5 % (Arild et al. 2017).

6.3. Other approaches to calculate the probabilities (for zero failure cases)

The challenge when calculating the probability of leakage in plugged and abandoned wells, is that there has been no data on the NCS indicating leakage, i.e. failure. Hence, one is dealing with zero failure cases. Even though there has not been observed any failures in the data, this does not prove that it is impossible in general. Following are some methods and other approaches to calculate the probability of leakage in P&A wells.

6.3.1. Minimax method

According to Razzaghi (2002), using the minimax estimation can be appropriate in cases where it is desired to estimate the probability of a rare event. Unlike the Bayesian estimation where one is averaging the risk, the minimax estimation looks at the least favorable scenario or worst possible risk for each decision, and chooses the decision giving the least value of the worst risk. In other words, the minimax approach minimizes the maximum risk. However, this method ignores all references to prior information. At the same time, if the prior information is poor or limited, the minimax method can be a good approach for estimating the probability of a leakage in P&A wells.

6.3.1.1. Example: Estimating probabilities using the minimax method (based on data from NCS)

For zero occurrence (Razzaghi, 2002):

$$p = \left[2 * \left(1 + \sqrt{N}\right)\right]^{-1} = \left[2 * \left(1 + \sqrt{5695}\right)\right]^{-1} = 0{,}00654 = 0{,}654\ \%\ \text{(within 1 year)}$$

N is the number of trials, which is calculated to be 5695 (see calculation in appendix).

Failure within 100 years: 48 %. How to calculate the probability of failure within 100 years is explained in the appendix.

6.3.2. Rule of three

There exists a theory called rule of three, which is a rapid way to estimate the probability of an event "x" occurring. It states, that if you have tested N cases and the event "x" haven't occurred, then the probability of "x" occurring is 3/N (Ludbrook and Lew, 2009). For this case, x = leakage, and N is the number of trials (calculated in appendix). The basis of this theory comes from using a 95 % confidence interval, which means that there is a 95 % chance that the probability of event "x" occurring lies in this interval (Ludbrook and Lew, 2009). In other words, finding the largest probability of "x" occurring that results in the probability of no successes out of n trials to be 0,05, which further means finding the p that gives: $(1-p)^n = 0{,}05$. By taking the logs on both sides, this gives: $n \log(1-p) = \log(0{,}05) \approx -3$. Additionally, since log(1-p) is approximately -p for small values of p, then the equation becomes: $p \approx 3/n$ (Ludbrook and Lew, 2009).

This approach uses a binomial distribution, as each trial is assumed independent and the result is either leakage or not leakage. One disadvantage associated with this method is that it doesn't take into account the change in failure rate over time.

6.3.2.1. Example: Estimating probabilities using the rule of three (based on data from NCS)

According to the rule of three, the probability of leakage within next year then becomes: 3/5695 = 0,00053 = 0,053 %. (N is calculated in appendix, at 5695).

Failure within 100 years: 1,05 %.

6.3.3. Laplace's rule of succession

Laplace's rule of succession is a formula used for events that have not occurred at all. This formula can therefore be suitable for the P&A wells on NCS, where the event of "leakage" has not occurred yet.

Laplace's rule of succession states that if one repeats an experiment N times independently, and get F failures (where the outcome is either failure or success), then the probability of failure in the next repetition is (Dale, 1995):

$$Probability\ of\ failure = \frac{F+1}{N+2}$$

Hence, this approach uses a binomial distribution.

6.3.3.1. Example: Estimating probabilities using Laplace's rule of succession (based on data from NCS)

$$Probability\ of\ leakage = \frac{F+1}{(N+2)}$$

Where F is the number of failures, i.e. F = 0. For this approach, N is calculated in the appendix, giving N = 5695. Further, this results in:

$$Probabilty\ of\ leakage = \frac{1}{(5695+2)} = 0{,}0001775 = 0{,}01755\ \%\ (within\ 1\ year)$$

The equation above is based on a uniform prior distribution beta(1,1).

Failure within 100 years: 1,76 %.

However, if we use Jeffreys prior beta(0.5,0.5), then the equation becomes:

$$Probability\ of\ leakage = \frac{1}{2*(N+1)} = \frac{0{,}5}{N+1}$$

If we insert N = 5695, then the probability of leakage becomes:

$$Probability\ of\ leakage = \frac{0{,}5}{5695+1} = 8{,}78*10^{-5} = 0{,}00878\ \%\ (within\ 1\ year)$$

Failure within 100 years: 0,87 %.

6.4. Recommended methodology to assess probabilities

The objective was to describe how long it takes before a leakage occur, using all possible information in a consistent way. Since there are only censored data available, there is no information about the distribution. This makes it difficult to use common methods such as MLE. Instead, one must assume a distribution based on a different type of information, e.g. expert knowledge, models etc. Further, one should use a Bayesian approach to combine this information.

In methods such as Laplace's rule of succession and rule of three, one uses a binomial distribution where the cases are seen as independent trials. Implicitly, one assumes that time is not a factor. However, by using Weibull or other continuous distributions, one includes that probability changes with time. As mentioned earlier, Weibull is commonly used due to its versatility.

The recommended methodology for quantification of probabilities is therefore to use the Bayesian approach together with the Weibull distribution. This method allows the use of only censored data as these are the only ones available. In addition, this method takes into account that the probability changes with time, as one assumes an increasing failure rate. Lastly, with this approach one may also include prior information available from experts, models etc.

7. Establishment of methodology for quantification of leakage rate to the environment

This forgoing chapter evolved around the probability of leakage and how one should proceed to quantify these numbers. Now, this chapter describes how to assess the consequences, i.e. leakage rates, assuming a leakage has already occurred. According to Watson and Bachu (2007), a leakage can develop if there exist a leak source (e.g. hydrocarbon-bearing formation), an available pathway and driving forces as e.g. buoyancy. In order to quantify the leakage rate for a P&A well, one should study the leakage rate potential for different pathways and integrate these into an overall assessment of leakage rate for P&A wells.

First of all, leakage pathways may be caused by several factors, including cement shrinkage, poor quality of cement placing, due to external or internal stresses (which may result in cracks or channels in the cement), poor cement bonding, chemical degradation or corrosion, or as a result of deterioration of cement bonds (due to changes in pressure and temperatures) (OP0713, 2015).

To quantify the flow rate through different pathways, one should address the possible leakage pathways. These are shown in figure 10, and includes (Gasda et al. 2014):

- Between cement and outer casing (a)
- Between inner casing and cement plug (b)
- Through cement plug (c)
- Through the casing wall (d)
- Through fractures or cracks in the cement (e)
- Between the cement and the formation (f)

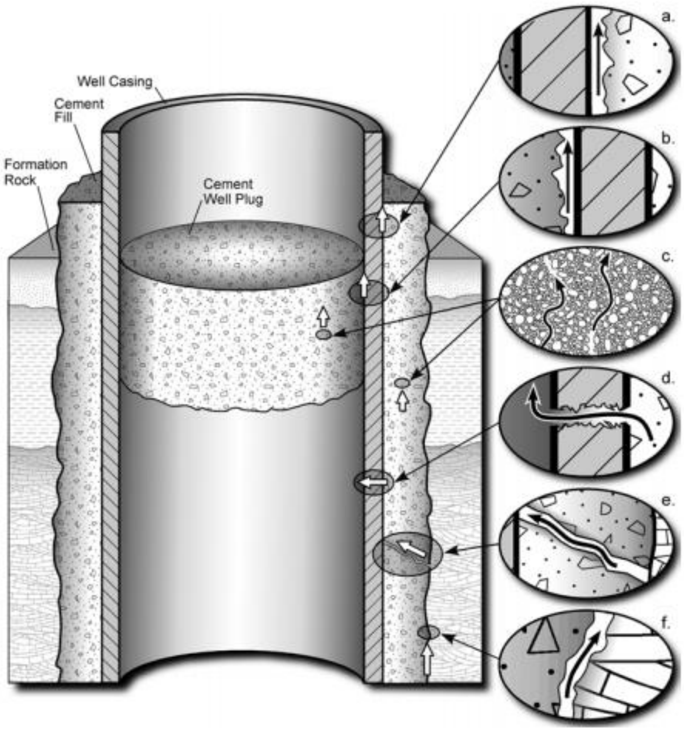

Figure 10. Possible leakage pathways (Gasda et al. 2014).

7.1. Leakage rate calculator

To assess the potential leakage rate of permanently plugged and abandoned wells, a simple leakage rate calculator has been developed by Ford et al. (2017). Different leakage pathways are here considered, and an estimation of the leakage rate for each of these pathways is assessed. The calculator then integrates this information in order to describe the overall leakage rate potential for a failed permanent barrier system (Ford et al. 2017).

According to Ford et al. (2017), the leakage calculator currently considers the following leakage paths: through bulk cement, fractures/cracks and in the micro-annuli (as a result of de-bonding). The following sections consider these leakage pathways and how to implement these into the leakage calculator.

7.1.1. Leakage through bulk cement

Leakage through bulk cement may occur partly as a result of poor cement or cement slurry design, due to issues during cement hardening or as a result of improper mechanical properties (Nelson and Guillot, 2006). Cement is a commonly used barrier material, and the cement has often a high content of water as this makes it easier to place the cement correctly. On the other hand, a high content of water in the cement also contributes to a destructive impact on the cement properties such as lower compressive and tensile strength as well as increased matrix permeability (Torsæter et al. 2013). To estimate the flow through bulk cement, which is a result of cement permeability, one should use Darcy's flow rate (Godøy et al. 2015):

$$Q = \left(\frac{kA}{\mu L}\right) * (\Delta P - \rho g L cos(\theta)$$

Where,

Q = flow rate [m^3/s], k = cement permeability [m^2], A = cross section of cement plug/annulus [m^2], μ = viscosity of reservoir fluid [Pa*s], L = length of cement plug/annulus [m], ΔP = difference in pressure between bottom of cement and top of cement [Pa], ρ = density of reservoir fluid [kg/m^3], and Θ = angle indicating well inclination at the depth of cement plug/annulus [º].

The cement permeability is here treated as an uncertain input. Implemented in the leakage calculator, lies a standard range of possible cement permeabilities, obtained by literature (Godøy et al. 2015). However, the user might also change this range, if desired.

7.1.2. Leakage through cracks

A plug is created when the injected cement has solidified, which is a result of the process called hydration. Cracks may then occur due to high tensile stresses resulting from hydration shrinkage (a decrease in plug volume due to exothermic reaction between water and cement). The effect of hydration shrinkage is related to the pressure and temperature which the cement encounter. To estimate the leakage rate through theses cracks, this equation by Sarkar et al. (2004) is used:

$$Q = \left(\frac{h^3 \cos \alpha}{12\mu}\right) * \left(\frac{\Delta P}{L}\right) * W$$

Where,

Q = flow rate [m^3/s], h = fracture aperture (perpendicular width of the fracture) [m], α = angle between fracture and the overall gradient axis which is controlling the flow [º], μ = viscosity of reservoir fluid [Pa*s], ΔP = difference in pressure between bottom of cement and top of cement [Pa], L = plug length [m], and W = fracture width [m].

Uncertain inputs for such cases are the fracture aperture, angle and width. Similar to the case of leakage through bulk cement, the leakage calculator has implemented a default or standardized range of values for these parameters. Again, the user can change these ranges if necessary.

7.1.3. Leakage through micro-annuli

Shrinkage of cement may also cause de-bonding, i.e. a separation between the plug and casing or between casing and the cemented annulus. This creates micro-annuli spaces in which fluid can migrate upwards. Micro-annuli may also be caused by improper mud-cake removal (bad cleaning job), casing decentralization (a casing centralizer prevents casing contacting the wellbore walls), free water channels, early set cement and formation strains and stresses (Ford et al. 2017). To estimate the potential leakage rate through micro-annuli spaces, the equation given by Aas et al. (2016) is used:

$$Q = \left(\frac{\pi R_C \Delta P}{6\mu L}\right) * \ \delta R^3$$

Where,

Q = flow rate [m^3/s], R_C = casing radius [m], ΔP = difference in pressure between cement on bottom and top cement [Pa], μ = viscosity of reservoir fluid [Pa*s], and δR = micro-annuli gap [m].

The uncertain parameter in these cases is the micro-annuli gap. Simultaneously, the leakage calculator includes a default range for values of micro-annuli gaps which also can be changed by the user.

7.2. How to use the leakage rate calculator in practice

The leakage calculator is a software tool that calculates the leakage rate and the associated uncertainty for P&A wells. In the development of this tool, an object-oriented programming language called C# were used. C# is developed by Microsoft and is based on both Java and C++. It was important that this tool was user-friendly to be able to assist in P&A planning. Therefore, graphical user interface (GUI) were applied. This interface provides graphical icons and visual indicator to the user which doesn't require the understanding of advanced coding (Deitel and Deitel, 2015).

The leakage rate calculator has two sets of inputs; deterministic and uncertain (Ford et al. 2017). The deterministic inputs include design variables such as plug length, hole diameter, virgin reservoir pressure etc. These are fixed values provided by the user. Figure 11 shows the interface where the user can provide these deterministic inputs.

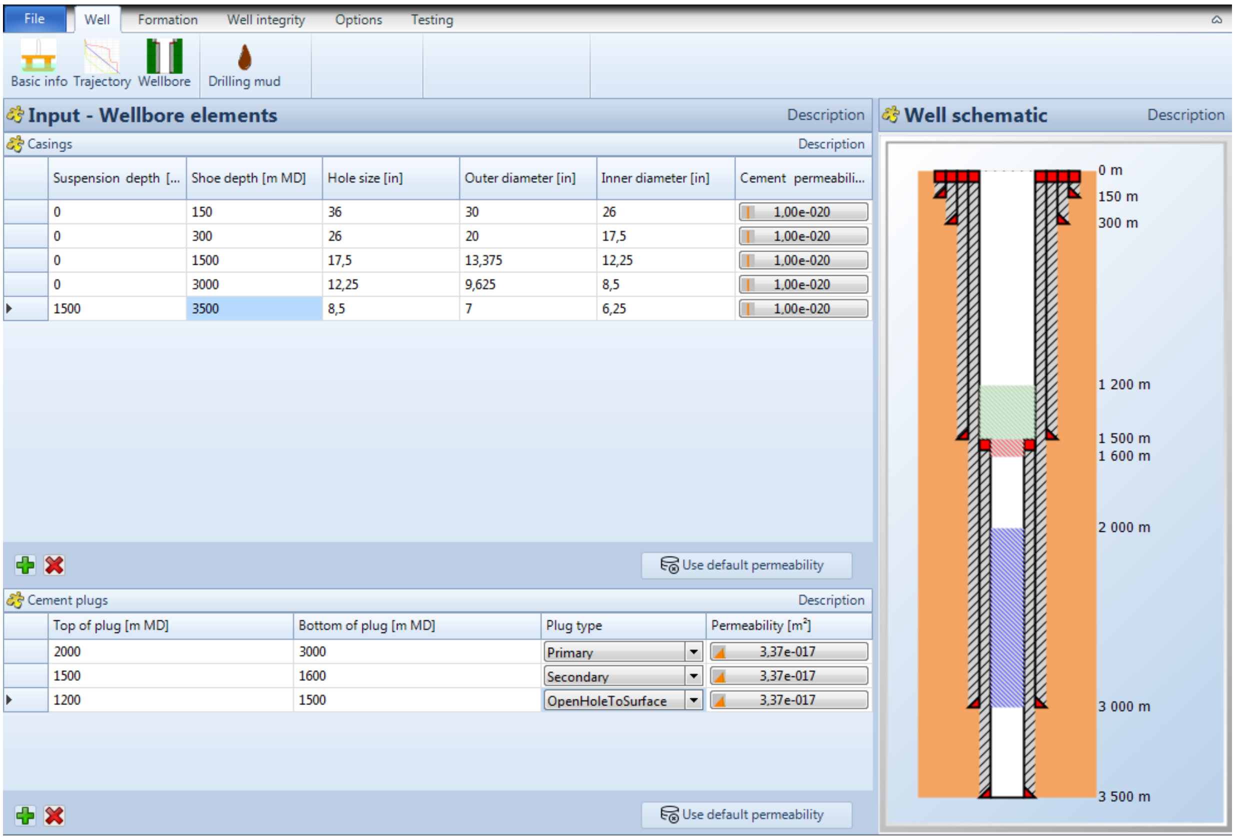

Figure 11. Leakage calculator – deterministic inputs.

As mentioned earlier when addressing the different leakage pathways, some parameters are uncertain. These inputs may include cement permeability, fracture width, micro-annuli gap size etc. In figure 12, it is shown how an uncertain input is processed in the leakage calculator. In this case, the permeability of the cement plug is not known. Uncertain inputs as this one, is represented using a probability distribution (as shown in figure 12).

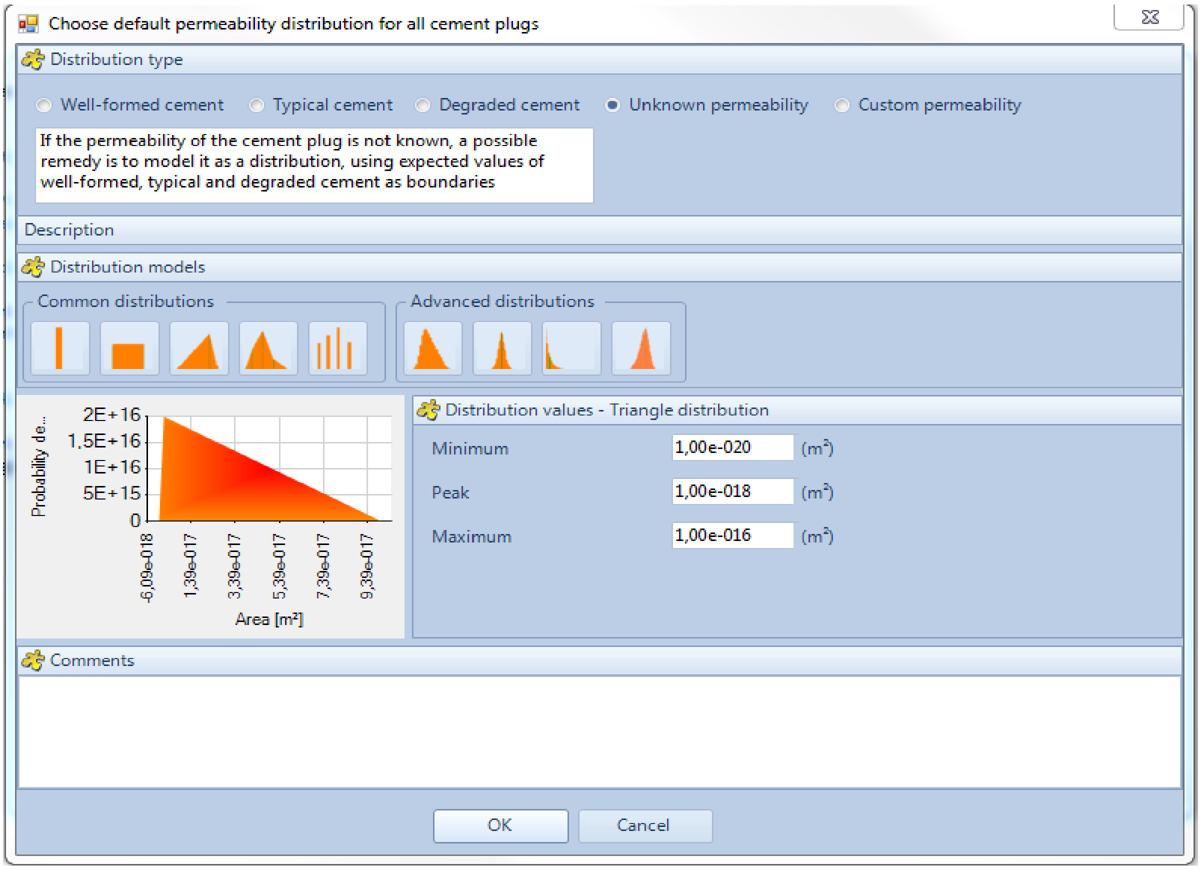

Figure 12. Leakage Calculator – uncertain inputs.

These inputs are then run inside a Monte Carlo simulation, resulting in an assessment of leakage rate and the associated uncertainty (as shown in figure 13). An advantage using this method, is that it considers the individual differences for each well, such as reservoir permeability and pressure (Arild et al. 2017).

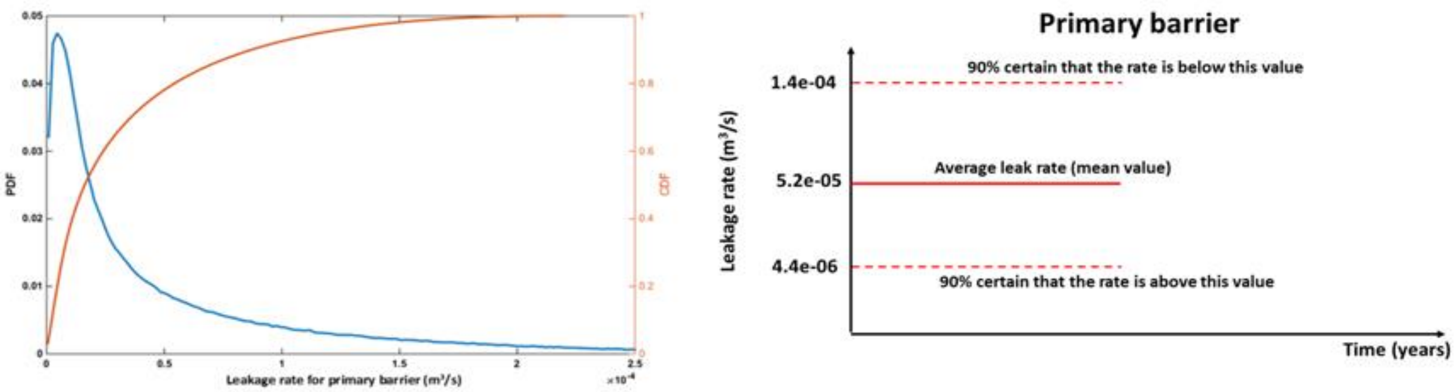

Figure 13. Leakage calculator – results.

8. Development of sensitivity analyses and importance measures for P&A planning and design: case-study

The next step in this process is to evaluate the quality of a given P&A solution with the associated costs. It is therefore interesting to study how a change in design parameters will affect the risk of leakage (with respect to leakage rate and probability), relative to the changes in costs. The following questions arises: Should a cheaper solution for P&A be accepted if it has sufficient quality? Is the increase in costs highly disproportionate to the benefit gained with respect to risk reduction? Do our prescriptive regulations today inhibit the chance of using more cost-efficient solutions for P&A?

8.1. Reference case

For this case-study, a high pressure / high temperature (HPHT) well is set as the reference case. A well is considered HPHT if it is deeper than 4000 m, has a reservoir pressure above 10 000 psi or if the temperature exceeds 150ºC (Aadnøy, 2010). This is a though well, a so called worst case well. Examples of HPHT fields in Norway are Kvitebjørn, Kristin and Gudrun (Equinor, 2018). The data used for this reference case is described in the appendix.

The general P&A solution for this well according to NORSOK D-010 Standard (2013), is to establish primary and secondary barriers, in addition to a surface barrier. This is shown in the well schematic (figure 14).

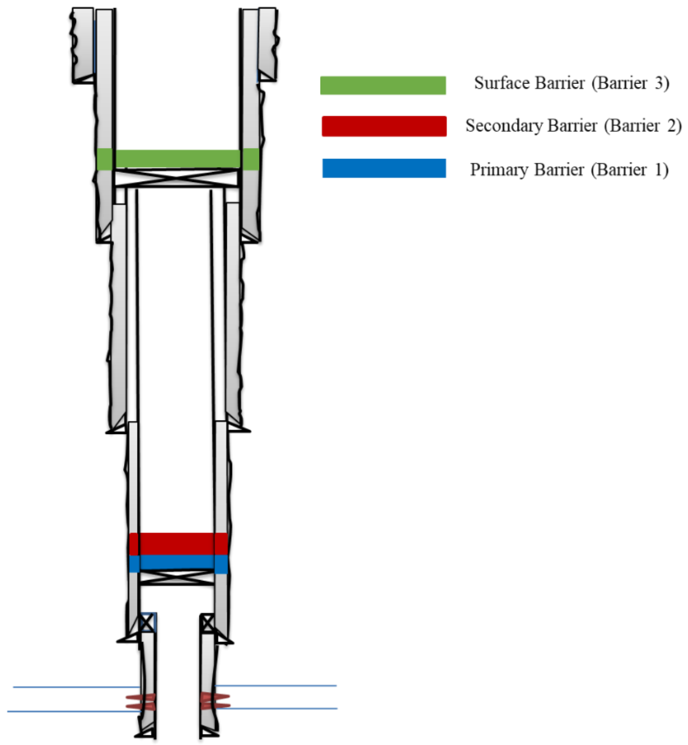

Figure 14. Well barrier schematic (Ford et al. 2017).

To simplify for educational purposes, only the primary barrier is considered in this case-study. In addition, the barrier is a formation to formation plug, i.e. no casing as part of the plug. Since there should be no casing as part of the plug, then milling operation is required. This operation is used to remove the casing, before setting a formation to formation plug in this milled section.

According to NORSOK Standard D-010 (2013), the plug length requirement if milling is set at 50 m. I.e. this scenario considers a 50 m of formation to formation plug, for a HPHT well.

8.1.1. Consequence picture – reference case

The consequence picture (showing leakage rate) for a HPHT well abandoned according to NORSOK D-010 Standards, is as follows:

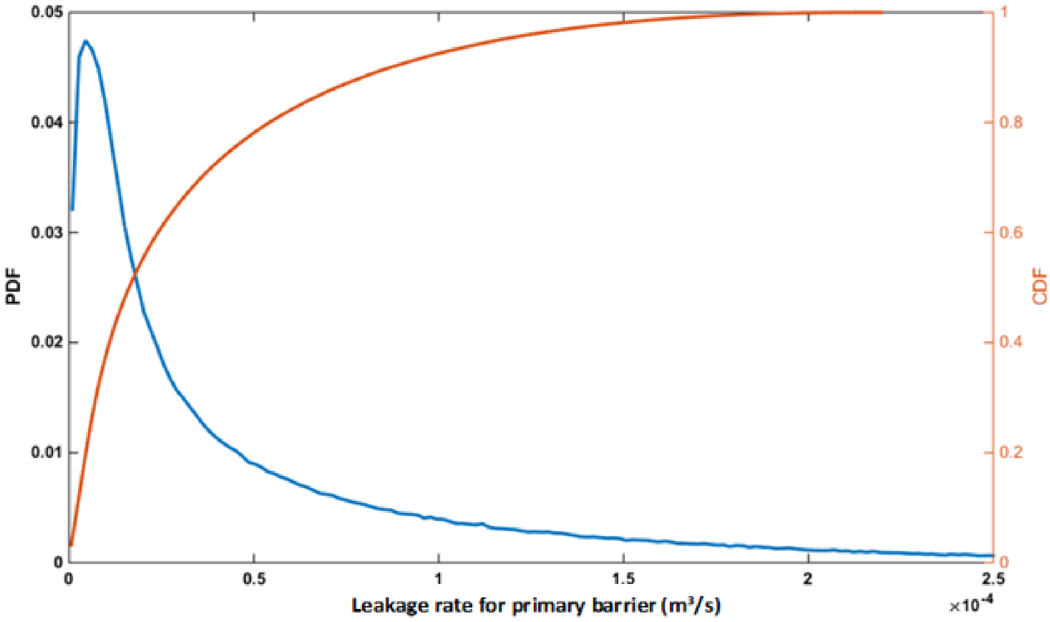

Figure 15. PDF curve and CDF curve.

In figure 15, the probabilistic leakage rate estimation is presented as a probability-density function (PDF) and a cumulative-distribution function (CDF). The x-axis here represents leakage rate. The y-axis in the PDF curve represents the occurrence probability corresponding to each value of outcome. In the CDF curve, the y-axis shows the probability that the outcome takes a value that is less than the corresponding value on the x-axis (Moeinikia et al. 2015).

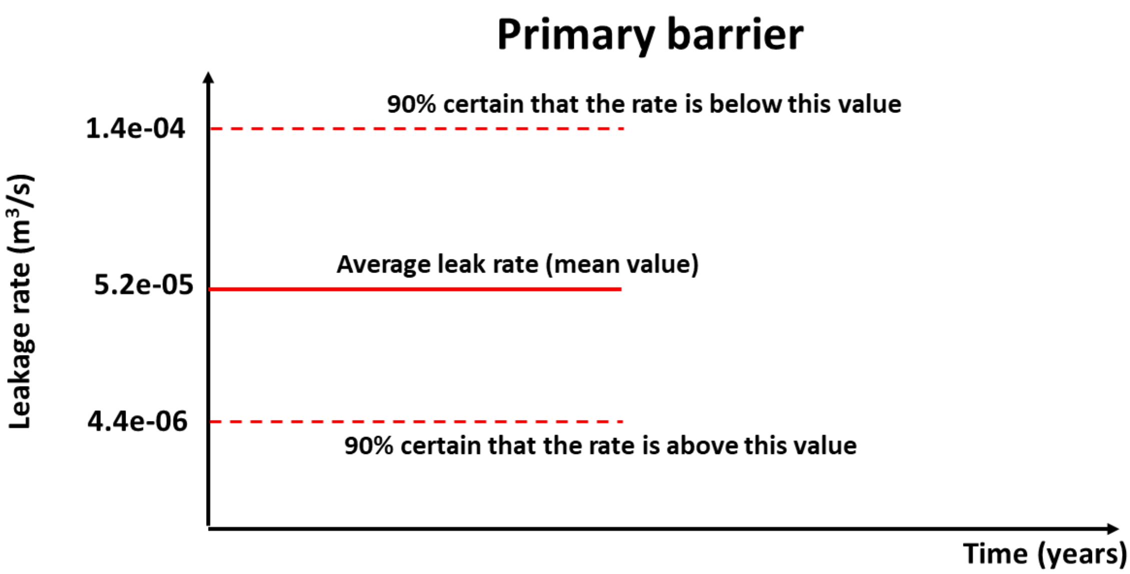

Figure 16. Leakage rate for primary barrier, HPHT well.

From figure 16, it is shown that the average leakage rate for a HPHT well with a 50 m formation to formation plug, is 5,2 * 10^{-5} m^3/s. This number is further used as a reference case. A HPHT well was chosen to act as reference case as this would be the maximum leakage rate a well abandoned according to regulations would have.

8.2. Establishment of the acceptance criteria for three different methods

These following methods are suggestions on how to set the acceptance criteria for P&A wells.

a) **Well consistency acceptance criteria (NORSOK D-010 req.)**

This method states that there should be consistency between wells when it comes to leakage rate (and probability). I.e. if one P&A well is considered acceptable, then all other wells should be accepted if it has the same (or lower) leakage rate. According to Godøy et al. (2015) one can have a reference case from a so called worst case well scenario and use this in a go or no-go decision for other wells when it comes to P&A. If using this method as acceptance criteria, then one can use the result from the reference case (studied in the first part of this case-study), where the leakage rate for a HPHT well abandoned according to regulations, were estimated. The average leakage rate for this scenario was estimated at 5,2 * 10^{-5} m^3/s. If using consistency between wells as acceptance criteria, it would mean that rates below (or equal) to this number is acceptable.

b) Environmental risk acceptance criteria (Natural seepage)

This method looks at the sustainability in the nearby marine biology and the natural seepage. If the marine environment can sustain the amount of HC leakage, and if the leakage is the same (or below) the natural seepage rate, then it is considered acceptable. The natural seepage rate was calculated earlier in this thesis, at a mean value of 1,1 * 10^{-2} m^3/s/seep. If using this natural seepage rate as acceptance criteria, it would mean that rates below (or equal) to this number is acceptable.

c) ALARP method

The recommended solution from chapter 5 is to establish the risk acceptance criteria using the ALARP method. This method is a combination of the two previous methods. As concluded earlier, the consistency between wells should reflect the lower criterion. I.e. if the leakage is below this point then it is acceptable, and no further action is required. The environmental risk acceptance criteria (natural seepage) should reflect the higher criterion (see argumentation in chapter 5.3). I.e. if the leakage is higher than this, then the risk is not accepted and must be reduced. If the leakage rate is in the area between these two, in the ALARP region, then the risk should be reduced as much as reasonably practicable. In the case that the costs are in gross disproportion with the benefit gained, then a reduction in risk is not necessary. This is reflected in figure 17.

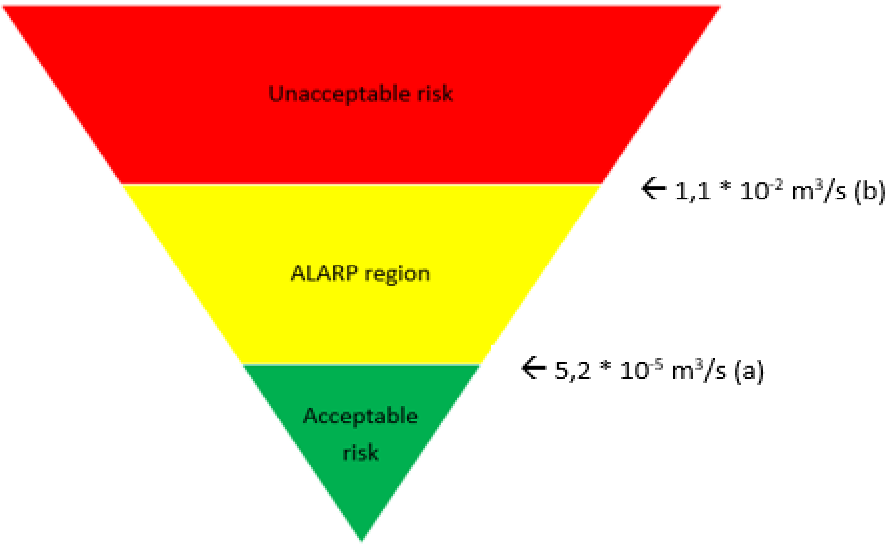

Figure 17. Acceptance criteria – ALARP method.

8.3. Example case

In the second part of this case-study, a low pressure / low temperature (LPLT) well is studied. Again, only the primary barrier is considered, and this is a formation to formation plug. The data used for this well is described in the appendix. These numbers are based on data used in the OTC paper written by Arild et al. (2017).

8.3.1. LPLT well with 50 m formation to formation plug

The consequence picture (showing leakage rate) for a LPLT well with 50 m formation to formation plug is displayed in figure 18.

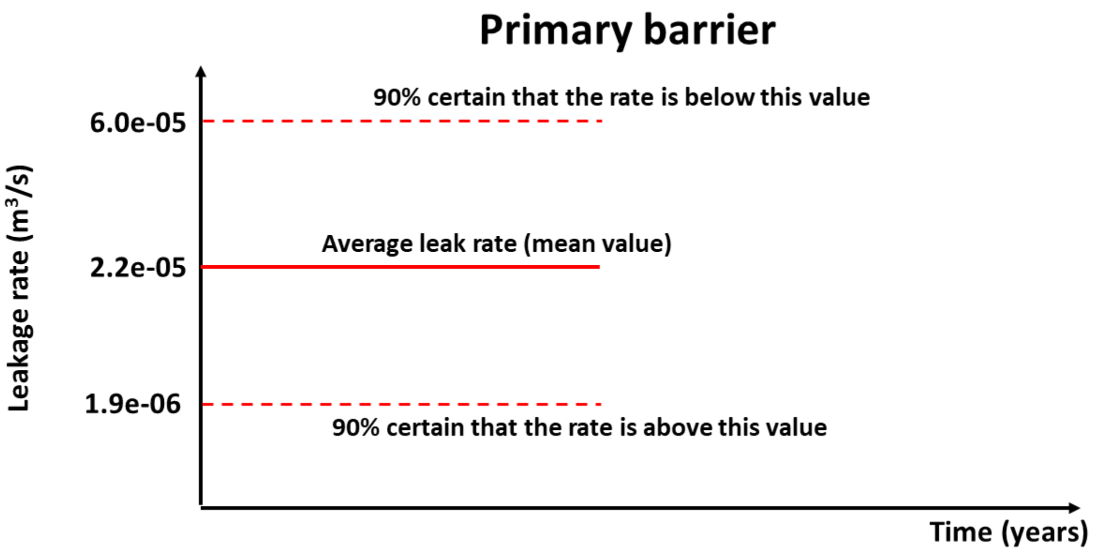

Figure 18. Leakage rate for primary barrier, LPLT well.

Then, in figure 19, the average leakage rate for this LPLT well (with 50 m plug) is compared to the acceptance criteria methods. In this chart, a logarithmic scale is used.

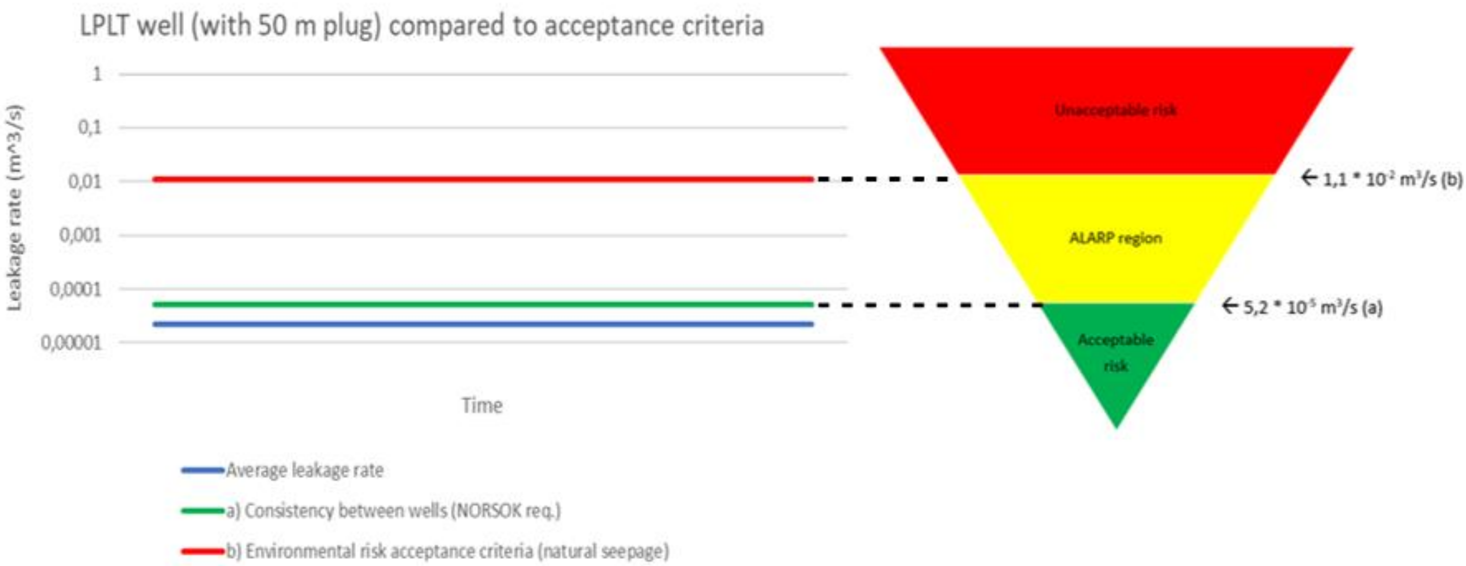

Figure 19. Average leakage rate for LPLT well (50 m plug) compared to acceptance criteria.

As seen in figure 19, a LPLT well with 50 m formation to formation plug will be in the acceptable region according to the acceptance criteria. Is it really necessary to have a 50 m plug for these types of wells, or could a lower plug length also be in the acceptable region? This result would imply that a shorter plug could also be considered acceptable.

8.3.3. Consequence picture of LPLT well with shorter plug lengths

Due to the results in the previous subchapter, it would be interesting to study a change in plug length, and how this affects the leakage rate (consequence). Today, due to a prescriptive regulation for P&A, the required plug length is fixed and portrayed in NORSOK Standard D-010. As stated earlier, if milling, one shall mill a section of 50 m and set the plug in this milled section. However, it would be interesting to see if a shorter plug length should also be acceptable for P&A, with respect to leakage rate.

Table 3 and figure 20 shows how different plug lengths will affect the leakage rate. The leakage rates are presented by the P10 (90 % certain that the rate is above this value), the mean value (average) and the P90 (90 % certain that the rate is below this value). In figure 20, a logarithmic scale is used.

Table 3. Leakage rate for different plug lengths.

Plug length	P10	Mean	P90
5 m	$1,8 * 10^{-5}$ m^3/s	$2,1 * 10^{-4}$ m^3/s	$5,8 * 10^{-4}$ m^3/s
10 m	$9,2 * 10^{-6}$ m^3/s	$1,1 * 10^{-4}$ m^3/s	$2,9 * 10^{-4}$ m^3/s
15 m	$6,1 * 10^{-6}$ m^3/s	$7,2 * 10^{-5}$ m^3/s	$1,9 * 10^{-4}$ m^3/s
20 m	$4,6 * 10^{-6}$ m^3/s	$5,4 * 10^{-5}$ m^3/s	$1,5 * 10^{-4}$ m^3/s
25 m	$3,7 * 10^{-6}$ m^3/s	$4,3 * 10^{-5}$ m^3/s	$1,2 * 10^{-4}$ m^3/s
30 m	$3,1 * 10^{-6}$ m^3/s	$3,6 * 10^{-5}$ m^3/s	$9,8 * 10^{-5}$ m^3/s
35 m	$2,7 * 10^{-6}$ m^3/s	$3,1 * 10^{-5}$ m^3/s	$8,5 * 10^{-5}$ m^3/s
40 m	$2,3 * 10^{-6}$ m^3/s	$2,8 * 10^{-5}$ m^3/s	$7,4 * 10^{-5}$ m^3/s
45 m	$2,1 * 10^{-6}$ m^3/s	$2,5 * 10^{-5}$ m^3/s	$6,6 * 10^{-5}$ m^3/s
50 m	$1,9 * 10^{-6}$ m^3/s	$2,2 * 10^{-5}$ m^3/s	$6,0 * 10^{-5}$ m^3/s

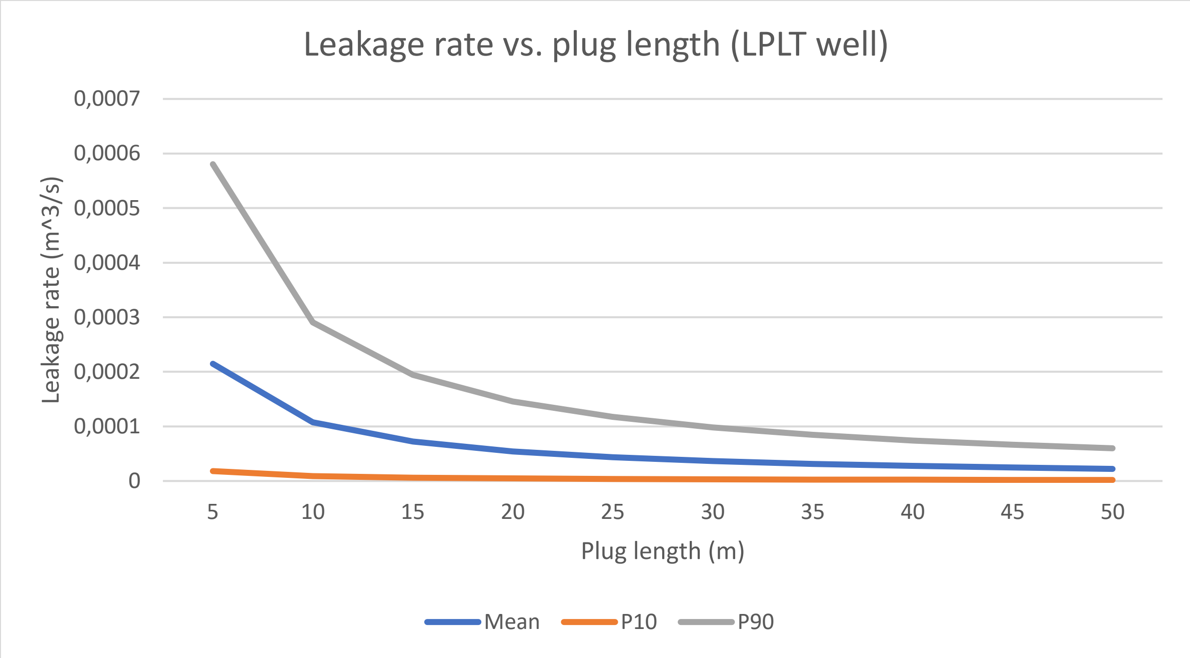

Figure 20. Leakage rate vs. plug length (LPLT well).

From figure 20, one can see that the lines indicating leakage rate flattens out after the length is approximately 25-30 m and longer. This would indicate that a change in plug length would here have a low impact on the leakage rate. I.e. implicitly saying that it doesn't really matter if the plug length is 30 or 50 m, as the leakage rate would be approximately the same.

8.3.4. Comparing results in example case with acceptance criteria – discussion

Further, figure 21 compares the average leakage rate for different plug lengths (from the LPLT case) with the acceptance criteria established earlier. Again, a logarithmic scale is used to present the leakage rates.

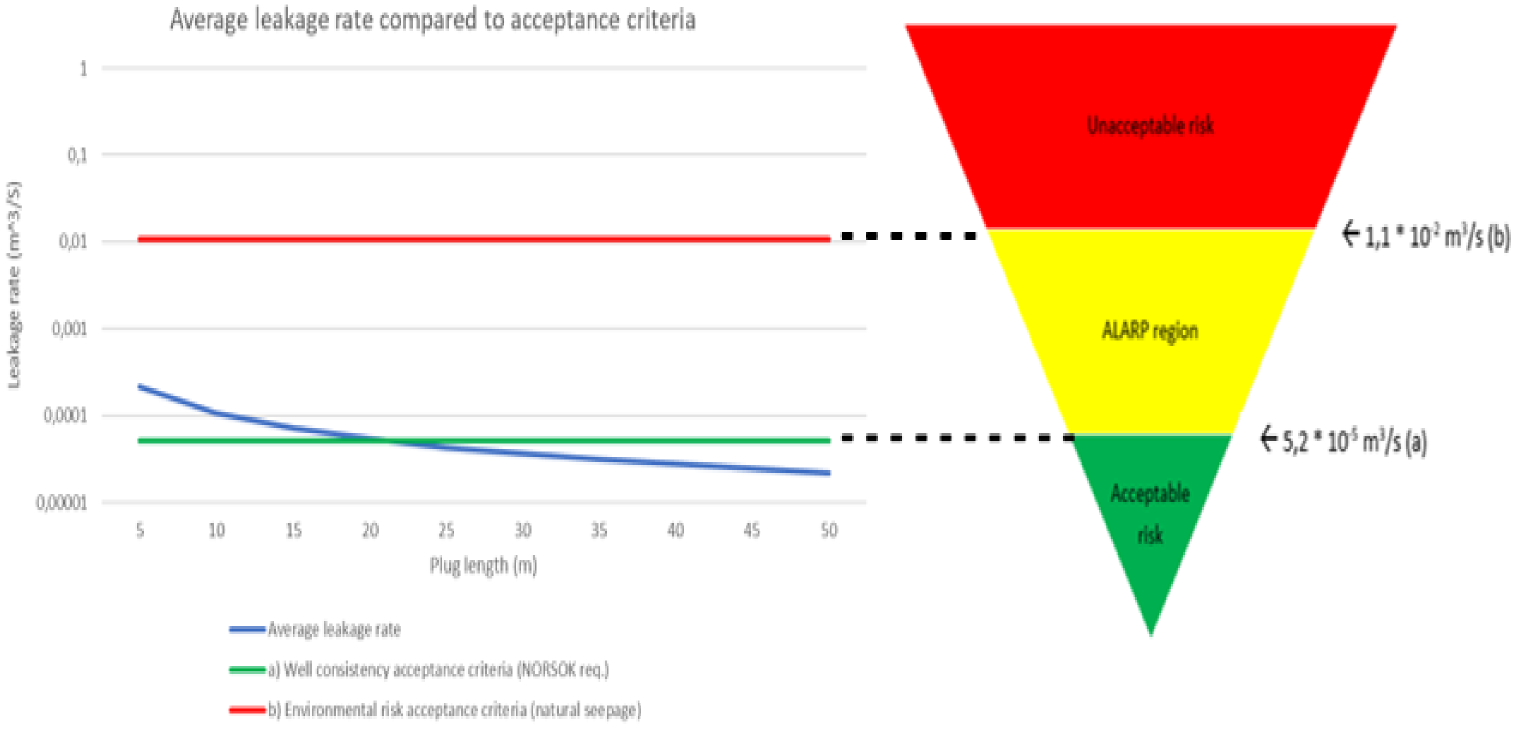

Figure 21. Leakage rate for different plug lengths (LPLT well) compared to acceptance criteria.

In figure 21, it is shown that a shorter plug length for LPLT wells would also be acceptable. Here, one can see at what plug length the average leakage rate for the LPLT well becomes higher than the requirement of 5,2 * 10^{-5} m^3/s (from the consistency of wells method, NORSOK req.). If the plug length for this type of well is more than approximately 22 m, then it is considered acceptable according to this method (a). If the plug length were less than 22 m, then the leakage rate is in the ALARP region, where the risk should be reduced unless the costs are in gross disproportion to the benefit gained. Again, one can see that if the plug is 30 or 50 m, it doesn't matter as both would be acceptable. The only difference would then be the costs related to the different plug lengths.

8.3.5. Costs vs. consequence

A change in plug length will affect the cost related to the P&A operation. A shorter plug will decrease the time spent on milling, as well as the time the cement needs to settle. However, the major contributor to costs is related to the milling operations. Therefore, this cost vs. consequence analysis is solely based on the time and cost related to milling different lengths.

According to a study performed by Halliburton (2013), milling a section of 50 m takes approximately 10 days to perform. It is, however, not known how much time milling a section of, say 20 m, takes. Therefore, one must make an assumption of how much time it takes to mill 10 m, 20 m etc. When performing a milling operation, multiple trips is required to change the knives on the cutting blades. The number of meters milled then stops when the knives are replaced. This is reflected in the black line in figure 22, which forms a staircase. To make a model of the time spent on milling different lengths, it is therefore suggested to have a straight line (see red line) in figure 22. The green line would most likely be a better fit, but it is difficult to know how bent this line should be.

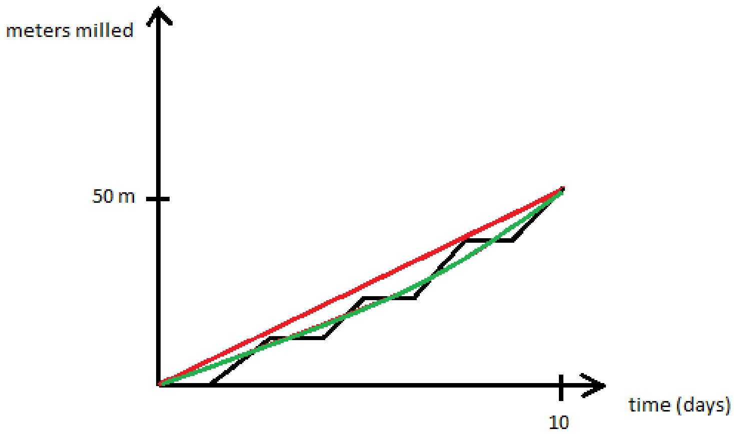

Figure 22. Model of meters milled vs. time

Since acquiring a more detailed and accurate model is challenging due to lack of information, this model (see figure 23) with a straight line is assumed good enough.

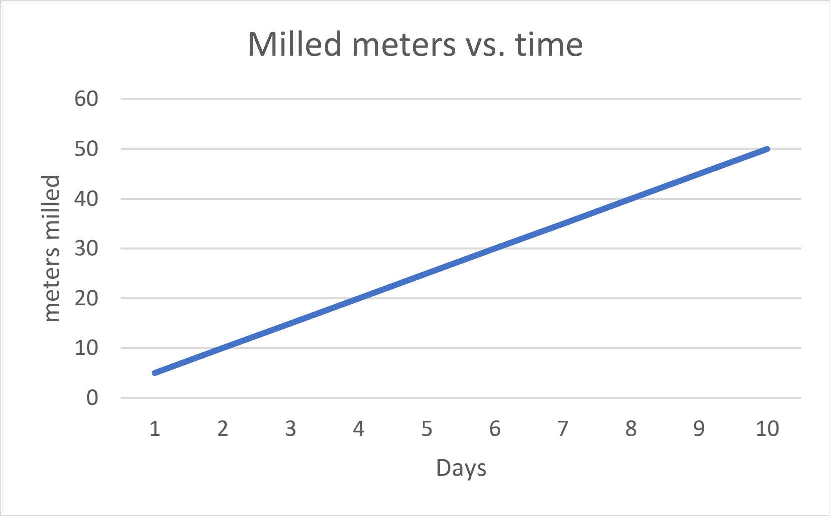

Figure 23. Milled meters vs. time.

Depending on the daily rig rate (X), the costs will be equal to X * days of operation.

8.3.5.1. Example 1 – Possible cost savings within acceptable leakage region

As shown earlier, a 30 m plug for a LPLT well should also be accepted with respect to leakage rate, compared to the acceptance criteria methods (see figure 21). Then it would be interesting to see how this changes the time and costs spent on setting this 30 m plug instead of a 50 m plug. According to figure 23, milling a 30 m section would take 6 days instead of 10 days (if milling a 50 m section). This would mean that 4 days can be saved. Further, if the daily rig rate were set at 3 MNOK, then the cost savings would be 12 MNOK (4 days * 3 MNOK/day = 12 MNOK), for one barrier within the well. I.e. one could save 40 % of the costs and still ensure an acceptable leakage rate. Remember that this case-study only considers one barrier, and the cost savings would be higher if the rest of the barriers also had shorter plug lengths.

8.3.5.2. Example 2 – Cost benefit analysis

It would also be interesting to study a plug length within the ALARP region, to see if the cost by reducing the risk would be in gross disproportion to the benefit gained by this risk reduction. In this example, a 15 m plug was compared to a 25 m plug, with respect to costs and leakage rate. A rig rate of 3 MNOK/day were used to calculate the costs.

Table 4. Cost benefit analysis.

Plug length	Leakage rate (table 3)	Costs (figure 23, multiplied with daily rig rate)
15 m	$7{,}2 * 10^{-5}$ m^3/s	9 MNOK
25 m	$4{,}3 * 10^{-5}$ m^3/s	15 MNOK

This would mean that by increasing the plug length from 15 m to 25 m, the leakage rate would decrease by $2{,}9 * 10^{-5}$ m^3/s, and it will cost 6 MNOK more. However, it is difficult to say right away whether the costs are in gross disproportion to the benefit gained.

If the plug is 50 m, then one can be more certain that there is a region of good and homogeneous cement. The shorter the plug becomes, this certainty decreases. This argues against having the 25 m plug instead of 15 m plug, just to be more certain that there is a region of homogeneous cement as part of the plug. However, there are also other aspects to consider in this discussion. E.g. the cement above (inside the casing) would act as a backup, and this should be taken into consideration in this discussion.

To get a sense of whether the costs are in gross disproportion to the benefit gained in this example, one suggestion is to compare the cost savings to insurance costs. If a well would need to be fixed later, this would cost money. Operators could therefore buy insurance against going back to fix the well.

Another suggestion is to study the possibility of the leakage rate becoming higher than the natural seepage rate at some point (in the unacceptable region). Then, one should include the probabilities, which is explained in chapter 8.4. If this rate becomes higher than the natural seepage rate at some point, then one should rather spend the 6 MNOK to get a safer well.

8.4. Probability weighted leakage rate

Until now, only the leakage rate has been considered in this case-study. However, it is not enough to consider only leakage rate, as the probability would affect the leakage rate as well. This is shown in figure 24, where the probability now is included in the leakage rate.

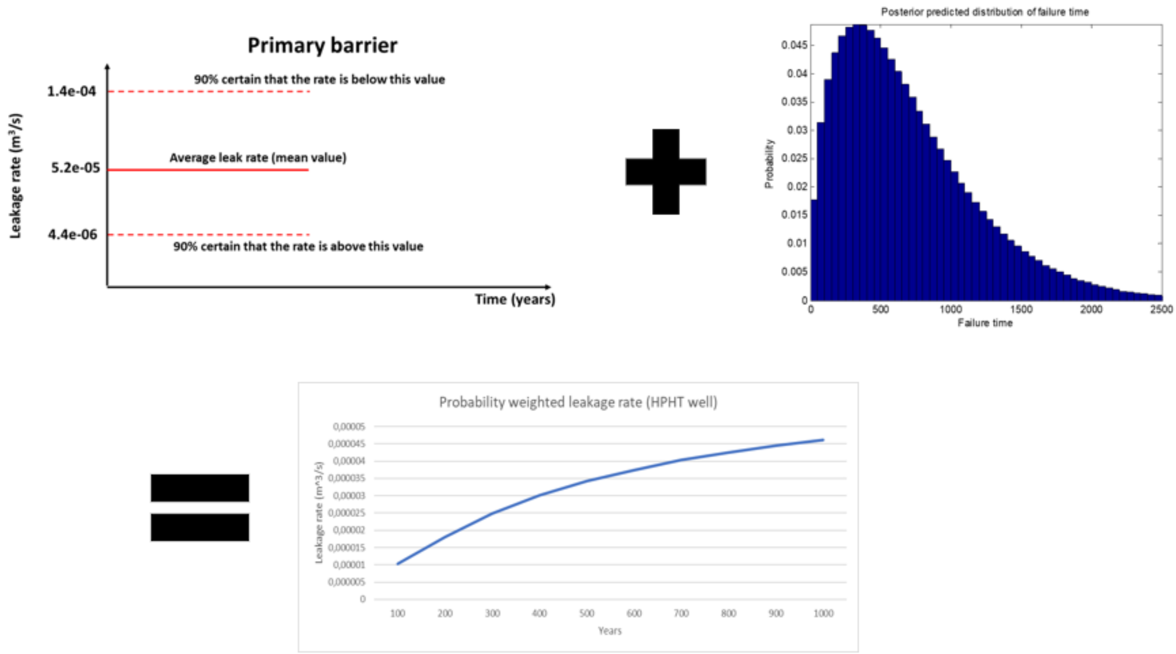

Figure 24. Include probabilities to average leakage rate.

Table 5 includes the probability of no leakages within different time periods, for both LPLT wells and HPHT wells.

Table 5. Probability of survival (no leakages) for LPLT and HPHT wells.

Years	Survival percentage posterior (LPLT)	Survival percentage prior (HPHT)
100	95	80
200	87	65
300	77	52
400	68	42
500	58	34
600	49	28
700	42	22
800	35	18
900	29	14
1000	23	11

In table 5, the middle column shows the probability of no leakages in a LPLT well within the different time periods (Arild et al. 2017). These are based on the assumed lifetime distribution and are updated with the censored data from the NCS. These censored data are primarily from LPLT wells, and it is therefore natural to use this middle column for the LPLT case. For HPHT wells, no data is available. Therefore, one could use the assumed lifetime distribution alone, with no updated data. Since the assumed lifetime distribution is not a result of any reflection around physics, but based on statements from experts, the assumed lifetime distribution does not take into account whether the wells are HPHT or LPLT, but assumes that they are reflected with the same distribution. Therefore, the recommended solution is to use the same distribution for the HPHT case as for the LPLT case, only there are no data available to update this distribution. Then, the probability of failure will be higher for the HPHT case, which is natural as these wells have a higher risk of leakage, as explained earlier in this thesis. However, the significance and validity of this statement can be discussed, but since there are no data available from HPHT wells, this is assumed best approach.

To calculate the probability weighted leakage rate, the starting point is to use the average leakage rate estimated earlier. Further, this leakage rate is multiplied with the percentage of failure for different time periods (1 – probability of survival). The result (for HPHT well – reference case) is shown in figure 25. Again, a logarithmic scale is used in this chart.

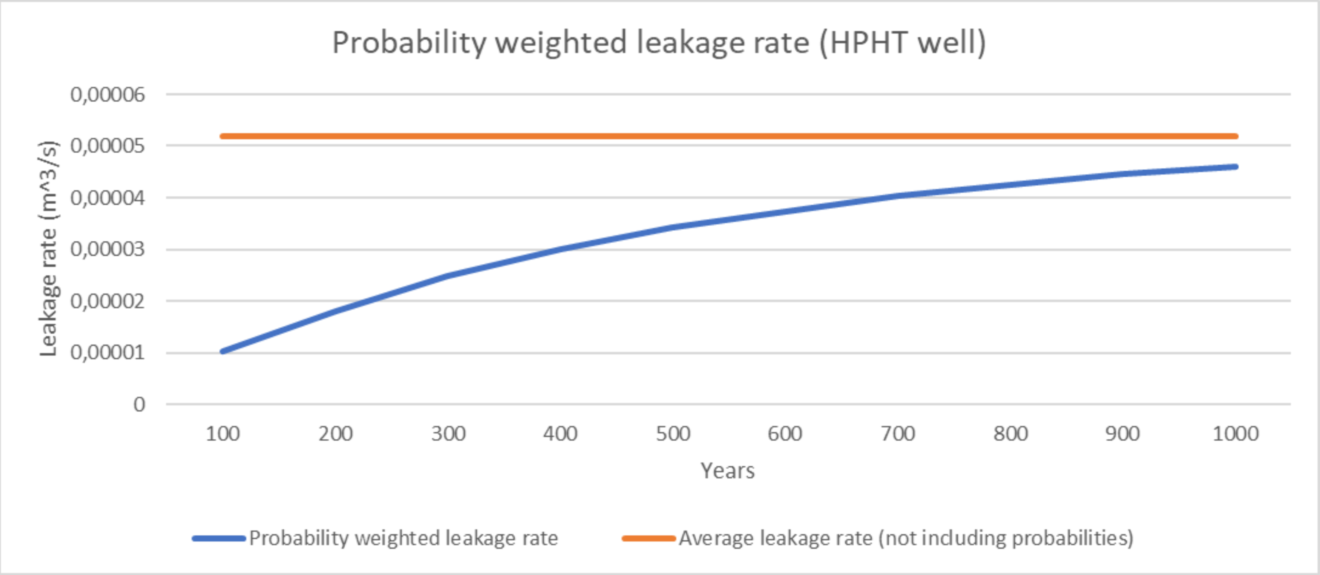

Figure 25. Probability weighted leakage rate vs. average leakage rate (not including probabilities) – HPHT well (reference case)

As seen from figure 25, the probability weighted leakage rate increases with time due to an increasing failure rate. However, the probability weighted leakage rate is below the average leakage rate (which not includes probabilities). Even after 1000 years, the probability weighted leakage rate is smaller than the average leakage rate estimated earlier. This implies that the actual leakage rate would be smaller due to a low probability of failure. This shows why it is important to consider the probability as well, and not only the leakage rate itself. The cut off period is set at 1000 years as this is assumed long enough.

In figure 26, the probability weighted leakage rate for plug lengths 10, 20, 30, 40 and 50 m for a LPLT well is compared to the acceptance criteria. The green line indicating the well consistency criteria is now also weighted. This is because this method reflects todays requirements in terms of leakage rate, which would also be affected by the probability of leakage. However, the natural seepage rate stays constant as this leakage is always present.

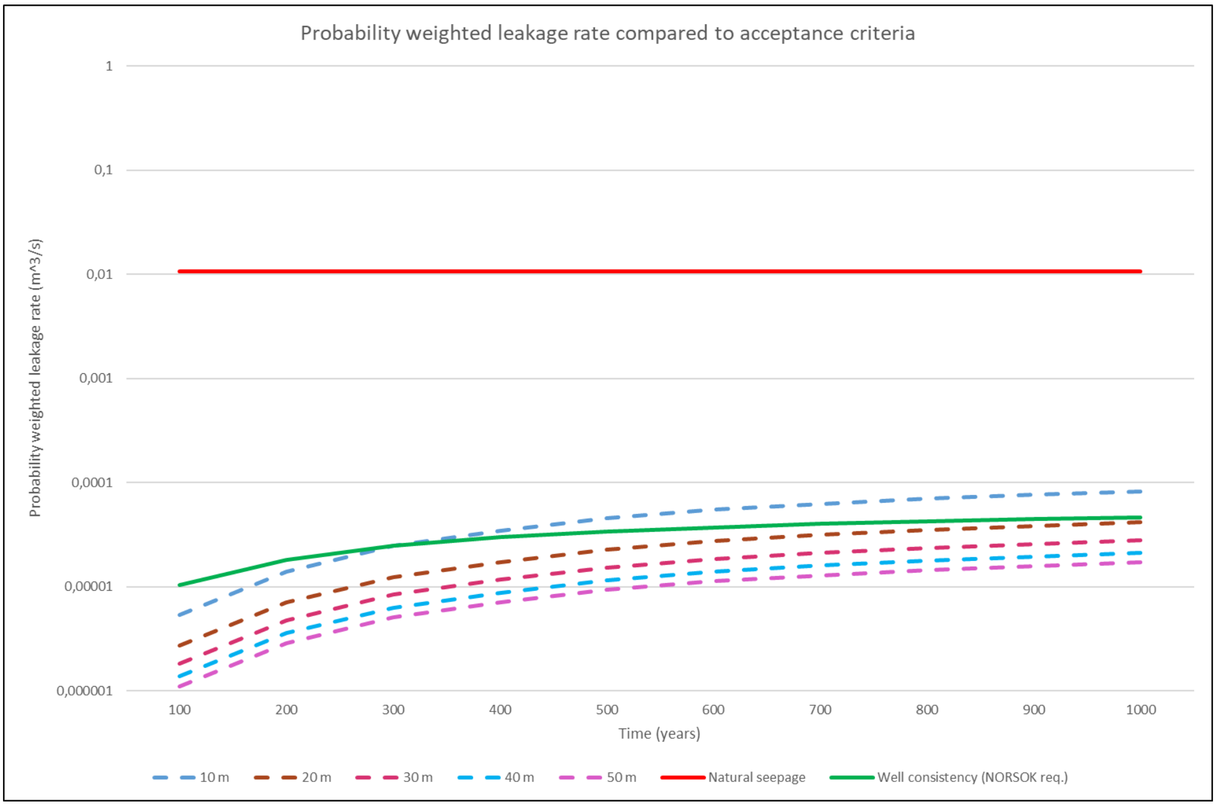

Figure 26. Probability weighted leakage rate compared to acceptance criteria (logarithmic scale).

Even when including the probabilities, it is shown that the 30 m plug for LPLT wells should be accepted, as this plug length is in the acceptable region (below green line).

Additionally, in the cost benefit analysis, where the two plug lengths of 15 and 25 m were compared, it was difficult to state whether the costs were in gross disproportion to the benefit gained. One suggestion was to see if the leakage rate for a 15 m plug would, at some point in time, become higher than the natural seepage rate, and if not, then a 15 m plug could be considered acceptable. From figure 26 it is shown that the leakage rate for a 15 m plug will be far below the natural seepage rate, even after 1000 years. This could imply that a 15 m plug should be acceptable. However, since it is difficult to know if this plug has a good enough length of homogeneous cement, then more research around this should be carried out before making this decision.

9. Conclusion

First of all, performing a risk assessment of P&A wells has provided important and necessary knowledge about leakage risk in P&A wells.

Further, this thesis has shown that having the same requirements for different wells are expensive and unnecessary. The conclusion is that it should be allowed to use a shorter plug length for wells that has a lower risk of leakage. Especially if the leakage rate is in the acceptable region, using the consistency between wells method. It was shown in the case study, that a risk-based regulation for P&A will ensure sufficient quality and allow for cost savings.

The quality of different P&A solutions is here measured in terms of leakage risk (probability and rate). This approach also makes it easier to see if other and newer solutions for P&A has sufficient quality. This would certainly increase the motivation of inventing new and cost-efficient solutions for P&A.

This thesis has therefore shown that a risk-based approach for P&A would benefit the industry both environmentally and economically.

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Appendix

Estimation of N (number of trials) from NCS data

Let N_i be the number of trials or wells tested in year *i*, where *i* goes from 1→48. Further, T_0 = 0 and N_0 = 333. If $T_i > T_{i-1}$ and $N_i <= N_{i-1}$, then the number of wells tested each year has the following equation; $N_i = N_{i-1} - N_{T_{i-1}}$. E.g. for abandonment year 0 (i.e. 2016), the number of wells tested were all the wells (333), and for abandonment year 2 (i.e. year 2015), the number of wells tested were 333 minus the ones abandoned in 2016. If these numbers are summed up together, total abandoned years for all of the wells is then estimated at 5695. The number of trials is therefore set at N = 5695.

Other calculations

Density of CO_2 used in calculations: 1,842 kg/m^3 (density of CO_2 at 1 atm and 20º C)

According to IPCC (2001), the global warming potential (GWP) of CH_4 (methane) is 23, relative to CO_2 (carbon dioxide). This number is therefore used in the calculations, when carbon dioxide is converted into methane.

Chapter 5.1.3. (Leakage rate in abandoned wells in UK)

1041 kg CO_{2eq}/well/year / (365 days * 24 h * 60 min * 60 s) = 3,3 * 10^{-5} kg CO_{2eq}/well/s

3,3 * 10^{-5} kg CO_{2eq}/well/s / 1,842 kg/m^3 = 1,8 * 10^{-5} m^3/well/s

To convert into methane: 1,8 * 10^{-5} m^3/well/s / 23 = 7,8 * 10^{-7} m^3/well/s

Chapter 5.1.4. (Emissions from cow)

One dairy cow emits 2944 kg CO_2/head/year.

2944 kg CO_2/head/year / (365 days * 24 h * 60 min * 60 s) = 9,3 * 10^{-5} kg CO_2/head/s.

9,3 * 10^{-5} kg CO_2/head/s / 1,842 kg/m^3 (density of CO_2 at 1 atm and 20ºC) = 5,05 * 10^{-5} m^3/head/s.

Converted into methane: 5,05 * 10^{-5} m^3/head/s / 23 = 2,2 * 10^{-6} m^3/head/s.

Chapter 5.1.4. (Emissions from power plant):

25 300 000 tons of CO_2 /plant/year:

25 300 000 000 kg CO_2/year / (365 days * 24 h * 60 min * 60 s) = 802 kg CO_2/plant/s

802 kg CO_2/plant/s / 1,842 kg/m^3 = 435 m^3/plant/s

Converted into methane: 435 m^3/plant/s / 23 = 19 m^3/plant/s.

Chapter 6.3 (How to calculate probability of failure / leakage within 100 years)

How to calculate probability of failure within 100 years:

1 – (probability of failure within 1 year) = probability of no failure within 1 year

(probability of no failure within 1 year)$^{100\ \text{years}}$ = probability of no failure within 100 years

Then, probability of failure within 100 years = 1 – (probability of no failure within 100 years)

Properties of HPHT well (reference case)

Properties of HPHT well (reference case)	
Inclination of well in barrier setting depth	55ºC
Virgin reservoir pressure	800 bar
Plug length (NORSOK D-010 requirement)	50 m
Hole diameter	0,311 m
TVD of BOC to the top of reservoir	130 m
TVD of TOC to the top of reservoir	4000 m
TVD	4200 m
Density of reservoir fluid	0,37 sg
Density of mud (water)	1 sg
Viscosity of reservoir fluid	66 sg

Properties of LPLT well (example case)

Properties of LPLT well (example case)	
Inclination of well in barrier setting depth	55ºC
Virgin reservoir pressure	300 bar
Plug length	50 m → 5 m
Hole diameter	0,311 m
TVD of BOC to the top of reservoir	130 m
TVD of TOC to the top of reservoir	2200 m →2226 m (see appendix p. 84)
TVD	2500
Density of reservoir fluid	0,45 sg
Density of mud (water)	1 sg
Viscosity of reservoir fluid	30 sg

TVD of TOC for different plug lengths (LPLT well scenario)

Plug length	TVD of TOC
50 m	2200 m
45 m	2203 m
40 m	2206 m
35 m	2209 m
30 m	2211,5 m
25 m	2214 m
20 m	2217 m
15 m	2220 m
10 m	2223 m
5 m	2226 m