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Author:
Stina Lima Monsen

Stina Lima Monsen

(Signature author)

Programme coordinator: Karina Sanni

Supervisor(s): Jan Aage Aasen (UiS) and Vidar Krone (OMV (Norge) AS)

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Abstract

A preselected Wisting well injector design has been used as a basis for this study. Because of the challenges following an ultra shallow reservoir and an almost negligible stress contrast between the reservoir and cap rock, the objective of the thesis has been to study the effect of the cement around the 9 5/8” liner, set in the reservoir. As a consequence, the packer placement, and hence the injection point, was changed accordingly. The well completion and well barriers were studied, with focus on two scenarios: fully cemented liner and non-cemented liner.

Due to the impact the annulus cement has on the barrier system, the two scenarios were evaluated in coherence with P&A operations, both temporary and permanent. Sketches were made and discussed, based on the original well design and the requirements and guidelines of the NORSOK Standard D-010 (2013).

To find the cementing services that fit the Wisting environment best, different cement types and cement evaluation tools from Schlumberger and Baker Hughes GE has been studied and evaluated. The service providers were contacted to discuss and obtain as good and useful information as possible.

The objective of the water injector is to be able to maintain matrix injection for as long as possible, due to the risk of potential fractures entering the cap rock. This risk increases significantly with a non-cemented liner. Fractures have therefore gained much focus, both in the theory section and in the simulation section. Many parameters change, both vertically and horizontally, and they are influencing the fractures and the injection. The effect of these parameters has therefore been simulated.

It was concluded that the cement as a barrier has a great impact on the performance of the injection well, and that a low-density cement slurry, in addition to a cement bond logging tool, would be the safest alternative in this type of injection well to ensure a successful cement job.

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I would also like to thank OMV (Norge) AS for the opportunity to study and write a real-case thesis about one of their projects, and for an amazing cooperation. I know that they have been really swamped during this period due to the start-up of another project, but I have felt great support and inclusiveness from everyone I have been in contact with within the company. I especially want to thank the Lead Drilling Engineer, and my supervisor, in OMV (Norge) AS, Vidar Krone. He is an incredible engineer, who has had an answer for all my questions. Vidar has devoted so much time for me in his busy schedule, for which I am really grateful. We have had meetings where he has given me advices, he has followed the progress of my thesis, and he has provided me with the information I have needed. I sincerely appreciate all his support and feedback. I would also like to express my gratitude to the Senior Geologist on the Wisting Development Project, Eirik Stueland. He has explained the geology and rock mechanics of the field, and the data behind the simulations. Eirik has answered several emails, invited me to study the core samples from the field, and he has given much appreciated feedback on the thesis. The last person I want to thank from OMV (Norge) AS is Senior Completion Engineer, Trygve Kamsvåg. Trygve has assisted me in the completion, barrier and P&A parts of my thesis. He has arranged meetings for explanations, answered so many questions on email, and checked several figures in the thesis and given me feedback. I have learned so much from him, and I am really grateful for all his support and assistance.

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Stina Lima Monsen

StinaLimaMonsen

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1. Introduction

1.1 Background

One of the main characteristics of the Wisting field is the depth of the reservoir. It is defined as an ultra shallow reservoir, with its location approximately 250 meters below seabed and a water depth of about 400 meters. This has naturally led to very low pressures and temperatures in the reservoir. Due to the low pressure, the natural flow of hydrocarbons from the reservoir to the surface is restricted, which made injection a requirement for optimal oil recovery. In addition to this, the Norwegian Government adopted the following requirements for produced water in the Barents Sea in St.meld. nr.38 (translated):

"*For emissions other than cuttings/drilling fluids and emission of produced water, and in cases where emission of cuttings and produced water occur, the general zero emission objectives will apply.*

- *It is stated additional requirements for activity in Lofoten – the Barents Sea, which are specified below: The activity shall be based on injection, or other possible technology, which prevents emission of produced water.*
- *A maximum of 5 percentage of the produced water can be discharged during operating deviations, provided that it is cleaned before discharged. The licensing authorities will impose exact cleaning requirements for specific activities.*
- *Cuttings and drilling fluids are re-injected or transported to land for disposal.*

(…)

The condition stating that there will be no emission of cuttings and produced water to the sea (physical zero emissions) represents a significant improvement in relation to the requirements that otherwise apply on the continental shelf. This means that if a licensee cannot demonstrate that the activity will meet the condition that there will be no emissions to the sea, it will be unacceptable with full-year petroleum activities on the relevant field within the area of Lofoten – the Barents Sea."

(Olje- og energidepartementet 2003).

The focus has therefore been on water injection (WI) and produced water re-injection (PWRI), and the possibilities for a horizontal water injector. There is one main challenge, which accompanies this alternative; the overburden fracture pressure is almost equivalent to the reservoir pressure, hence the stress contrast between the reservoir and the cap rock is close to zero. In addition to this, there is lack of a sandstone layer, or a buffer zone, above the reservoir that can compensate for a potential fracture through the cap rock. This challenge eliminates the possibility of fractured injection due to the shallow reservoir and the risk of fracture propagation into the cap rock and further up to the surface, leaving matrix injection as the only alternative.

The consequences of a fracture propagating through the cap rock and to the seabed would be enormous, both environmentally and economically. It means that there would be communication between the reservoir and the surface, with no barrier or control of flow. The oil always flow in the least resistant direction, as all fluids do, and as most fractures have a higher permeability than a permeable sand (Tipura et al. 2013), the risk of oil migration through the fracture is very high. Oil migration through a fracture up to the seabed could result in a loss of several million bbl (barrels) of oil, which would pollute the sea and environment around this area, affecting the life in and around the sea, as well as it would be a significant economic loss.

1.2 Problem definition and objective

Water injection is crucial for the recovery factor on the Wisting field. The shallow reservoir on Wisting with low overburden coverage makes safe water injection a key focus point for the development. Injection pressure needs to be monitored closely to ensure not exceeding the stress constraints of the cap rock (minimum horizontal stress). Well integrity is the main focus throughout the life of a well, and well barriers play a crucial role in being able to achieve the required injection pressures/rates. It is important that the well design eliminates leakage to the surface, as well as kicks and blowouts, and the thesis will evaluate the impact of the barrier management on the allowable safe injection pressure/rate. One of the main barrier elements for the current water injection well design is cement. The casing and liner cement, and hence the cementation job of the casings and liners, is an important part to maintain well integrity. The quality of the cementation job affects both the injection pressure and the injection performance over time. It is especially critical in the last cased section of the well, where the liner enters the reservoir.

The concept of this thesis is therefore the cement as a barrier, throughout the life of well, with a special focus on the cementing of the 9 5/8" production liner. The main task will be to investigate the impact on water injection pressure/rate as a function of cement quality. Two liner cement scenarios will be evaluated. To pinpoint the effect, two entirely opposite scenarios have been chosen; one scenario where the liner is fully cemented, and one scenario where the cement job has failed and there is no cement behind the liner at all.

Focus will be on the evaluation of cement quality to be performed, and the assessment of the cement quality. To verify the cement as a barrier, the cement has to be logged and evaluated after it has set in the annulus. This part will include involving service providers and previous experience from the Wisting field.

Simulations will be run to evaluate the effect different parameters have on the injection performance, and to show the impact if the minimum stress at a shallower depth has to be used as a constraint for the injection pressure. Poor cement quality could be one of the reasons for this scenario. The injection rates will be simulated in Reveal to show the impact of impaired barriers.

2. The Wisting field

2.1 Field overview

Figure 2.1: Location of the Wisting field in the Barents Sea (Drangeid 2018).

The Wisting discovery in license PL537 is located in the south-western Barents Sea, approximately 310 km north of the Norwegian coast (Figure 2.1), and is the northernmost oil discovery on the NCS (Norwegian continental shelf). It is far from shore, and a detailed HSSE plan has to be executed prior to operation start-up. As the location of the field is as far north as it is, the temperatures are low through the whole year, but especially critical during the winter. The low temperatures can lead to ice development on the equipment, making ice resistance an important evaluation. In addition to the risk of ice, there are also polar nights during the wintertime, which means that there is darkness 24/7 (Drangeid 2018).

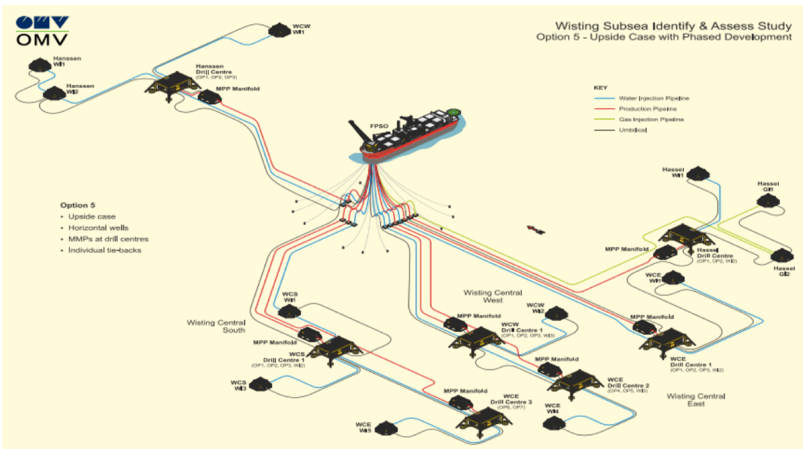

Figure 2.2: Wisting subsea development alternative (OMV (Norge) AS 2016).

The main reservoirs on Wisting are defined as ultra shallow reservoirs as the upper level lies about 250 meters below the seabed. With a pressure of approximately 70 bars, and a temperature of approx. 17°C, the reservoirs are defined as LPLT (low pressure, low temperature) reservoirs. The Wisting field is divided into six segments; Wisting Central East, Wisting Central West, Wisting Central South, Hanssen, Hassel and Bjaaland, and due to a water depth of about 400 meters, a subsea development plan with a floater has been carried out for the field (Figure 2.2) (OMV (Norge) AS 2016).

2.2 Existing wells

Six wells have been drilled on the Wisting field so far: 7324/8-1 (Wisting Central), 7324/7-1S (Wisting Alternative), 7324/7-2 (Hanssen), 7324/8-2 (Bjaaland), 7324/7-3S (Wisting Central II), and 7324/8-3 (Wisting Central III) (Drangeid 2018; NPD 2019). The location of the wells and their trajectory is shown in Figure 2.3. The figure also shows the faulted nature of the field, and how the faults are affecting the reservoir locations. The faulting is what defines the segments of the fields, as described above (OMV (Norge) AS 2018b). The horizontal well, Wisting Central II, was drilled through three known faults as indicated by seismic interpretation. However, as can be seen in Figure 2.3, there is a fourth fault in the beginning of the horizontal section. This was an unknown fault section not identified on the seismic pre-drill due to the small offset of the fault (OMV (Norge) AS 2018e). Data acquired from the existing wells, in addition to seismic interpretation, has now formed a detailed mapping of the geology of the field.

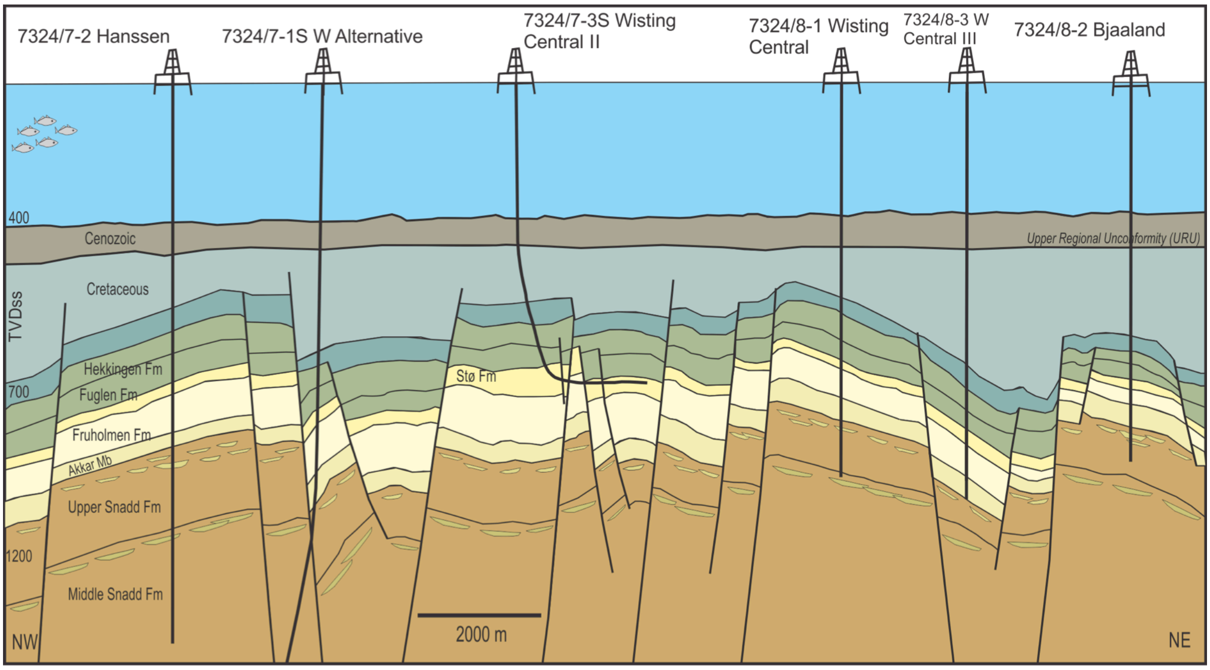

Figure 2.3: Well locations and formation layers (OMV (Norge) AS 2018a).

2.3 Geology

The Wisting license is located in the Hoop Fault Complex on the Bjarmeland Platform, close to the Maud Basin in the South West (OMV (Norge) AS 2018b). In the shallow part (Hekkingen Fm. (formation) and Kolmule Fm.), it is expected reactive clays, as seen by some of the overburden drilling in previous wells, and it is possible to experience hydrates. Shallow gas has not been encountered by any of the existing wells (OMV (Norge) AS 2018e). The main reservoir is located in the shallow marine Realgrunnen Subgroup (Sg.) from the Middle Jurassic age (Trauner et al. 2015). The different formations are explained below, and Figure 2.4 illustrates the formations from the Kolmule Fm. in Cretaceous to the Snadd Fm. in Triassic, as well as the tectonic activity at the time.

The formations on the Wisting field have a much higher strength than expected at these shallow depths. Formations on the same depths in other locations are normally much weaker and less consolidated. The reason for this is that the Wisting field has been buried down to approximately 1700 m TVDss, but was later uplifted, causing erosion of the shallower sediments. These events have strengthened the formations, providing stable wellbores despite the low pressures and the shallow setting. This is also seen in other parts of the platform areas in the Barents Sea, and has been documented in several papers (Ktenas et al. 2017; Farazani 2017).

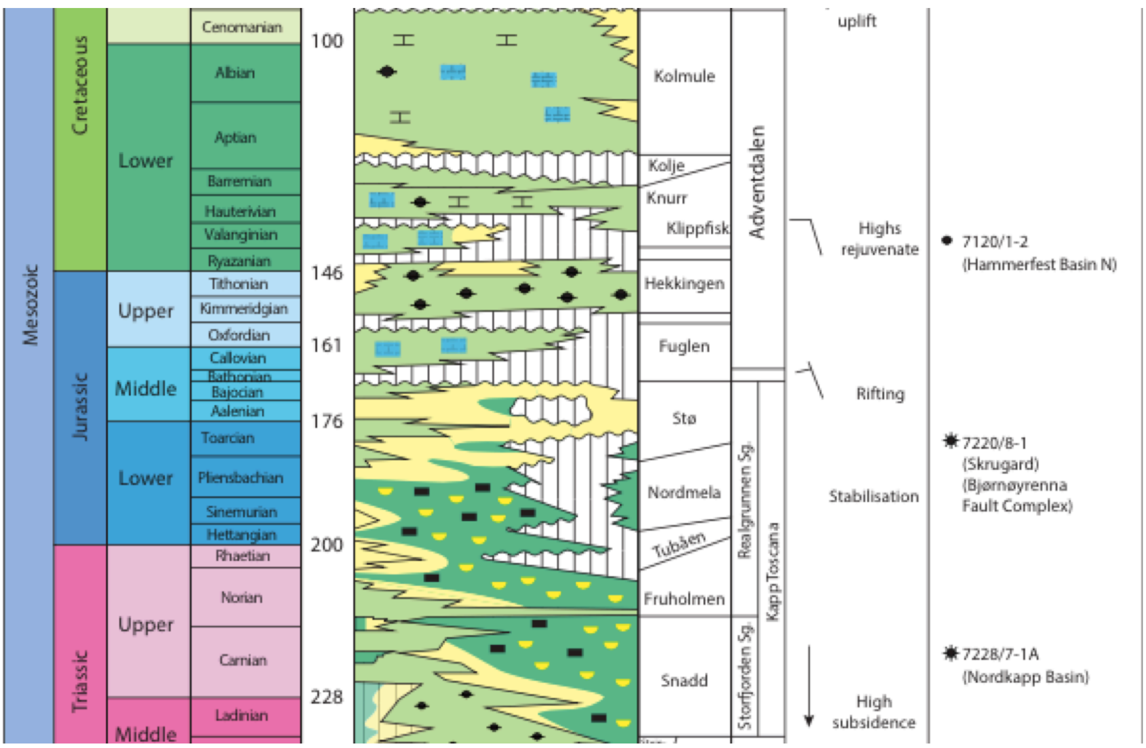

Figure 2.4: The geology on Wisting and the tectonic movement (OMV (Norge) AS, modified after Nøttvedt et al. 1993 and Larssen et al. 2002).

2.3.1 Kolmule Fm. and Kolje Fm.

Both the Kolmule Fm. and the Kolje Fm. comprise of claystones from Cretaceous, and was deposited in an open marine environment (NPD 2019; Trauner et al. 2015). Eirik Stueland (2019) explained that there is an approximately 40 m thick Quaternary section above the Kolmule formation (Cretaceous), which has had several ice depositions during the last 20 000 years. These layers are very 'soft', revealing the scrape signature of the last ice age on the seabed, as seen on the bathymetry map (Figure 2.5).

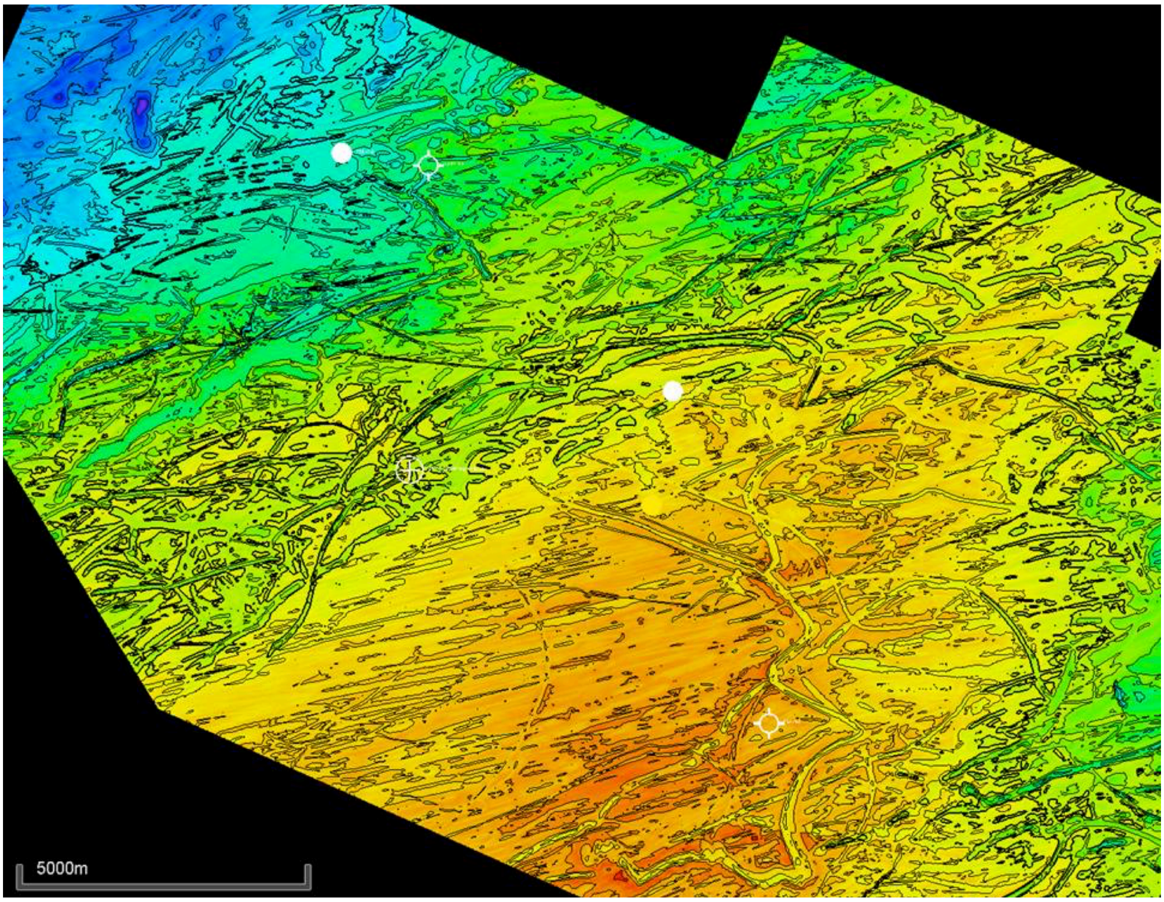

Figure 2.5: Bathymetry map (Stueland 2019).

2.3.2 Hekkingen Fm.

The Hekkingen Fm. is one of the main source rocks for the hydrocarbon accumulations in the Barents Sea, and it is also present in the Hoop wells. It mainly consists of claystone from Jurassic, which was deposited in a deep-water marine environment (NPD 2019; Stueland 2018; Trauner et al. 2015).

2.3.3 Fuglen Fm.

The Fuglen Fm. is the acting cap rock in the Adventdalen Gp. (group) from the Jurassic age. The lithology of the formation is mudstones that are interbedded with thin limestones. The fine grained lithology indicates that it was deposited in a marine environment, and there were apparently some tectonic movements during the deposition (NPD 2019).

2.3.4 Stø Fm.

The Stø Fm. is the main reservoir on Wisting, and it is part of the Upper Realgrunnen Sg (Trauner et al. 2015, modified after Nøttvedt et al. 1993 and Larssen et al. 2002). The formation was deposited in the Lower- to Middle Jurassic, and is dominated by fine to medium-grained, well-sorted sandstones that were "*deposited in prograding coastal regimes*" (NPD 2019). This means that the depositional environment was a moderate wave-energy shoreline system; from distal transition zone to upper shoreface with sea level rise (OMV (Norge) AS 2018b). The Stø Formation in the Wisting area mainly consists of homogeneous sandstones (NPD 2019). Data collected from Wisting Central II show a "*high quality reservoir with high porosity, high oil saturations and prolific flow potential*", as well as very high permeability (2500 mD) in the clean, sandy areas (Trauner et al. 2016). The thickness of the high quality sand in Stø ranges from 16.1 m (the Bjaaland well) to 23.6 m (the Hanssen well), with an average thickness of the formation of around 20 m (OMV (Norge) AS 2018b). The minimum horizontal stress in the reservoir is relatively low, resulting in a potential fracture propagating upward. In addition to this, it has been confirmed that there is no reliable stress contrast between the reservoir (Stø) and the cap rock (Fuglen), which means that the range of allowable injection pressure is small (Stueland 2018).

2.3.5 Nordmela Fm.

The Nordmela Fm., together with the Tubåen Fm., constitutes the middle part of the Realgrunnen Sg from Jurassic. Nordmela is also one of the reservoirs on Wisting, with an up to 5 m thick sandstone (Wisting Central & Hanssen), which was deposited within a lower- to upper shoreface environment (OMV (Norge) AS 2018b). However, the Nordmela Fm. is thicker in the Wisting Central II well, with better reservoir quality. The Nordmela Fm. is regarded as a part of the main reservoir in the Wisting development project, with the same reservoir quality as the above lying Stø Fm. in parts of the field (OMV (Norge) AS 2018b). The reason for the variation in thickness is the interpretation that the formation is filling the undulating Triassic – Jurassic unconformity, which varies throughout the Wisting field. The

Tubåen Fm. is not present in any of the Wisting wells, and has likely been truncated/eroded in the lower Jurassic time (Stueland 2018).

2.3.6 Fruholmen Fm.

The Fruholmen Fm. constitutes the reservoir part of the Realgrunnen Sg. that was deposited in Triassic, i.e. the lower part of the subgroup. The lithology consists of a "*marine, shaly lower part, a fine to medium-grained sandstone in the middle, and a coastal plain facies in the upper part*" (OMV (Norge) AS 2018b). Fruholmen was deposited in a shallow marine bay environment and passed up into muddy coastal plain strata, which provided the depositional environment for the shaly upper part. There are some uncertainties about the communication between the Fruholmen reservoir and the Stø reservoir due to this shaly upper part of Fruholmen, as well as some parts of Nordmela. In the Late Triassic to Early Jurassic, there was an uplift of the structural height east of the Maud Basin. Some of the Fruholmen Fm. was eroded, and it is assumed that the eroded sediments were re-deposited in the Stø Fm. (NPD 2019; OMV (Norge) AS 2018b).

2.3.7 Snadd Fm.

The Snadd Fm. could have high potential as a reservoir (Triassic), with the source rock Steinkobbe Fm. just beneath (Stueland 2018). However, several wells have penetrated these high quality fluvial channel sands, but none have so far been hydrocarbon bearing. The Snadd Fm. is therefore not part of the development plan for the Wisting project (OMV (Norge) AS 2018b).

2.3.8 General

Due to the many faults on the Wisting field, the hydrocarbon-bearing formations (amongst other formations) are slightly tilted; hence, the producers will be drilled in the upper part of the reservoir, while the injectors will be drilled in the lower part, giving the injectors a higher pressure to work with.

3. Base case design

The design process follows the OMV-EP Standard "Casing Design Standard EP-EPPWE-06-00" as well as NORSOK D-010 rev.4 recommendations (OMV (Norge) AS 2018e).

The base case design of the injection well is based on the Wisting Central II design (Figure 3.1). Wisting Central II is the first and only horizontal well on the Wisting field, for the time

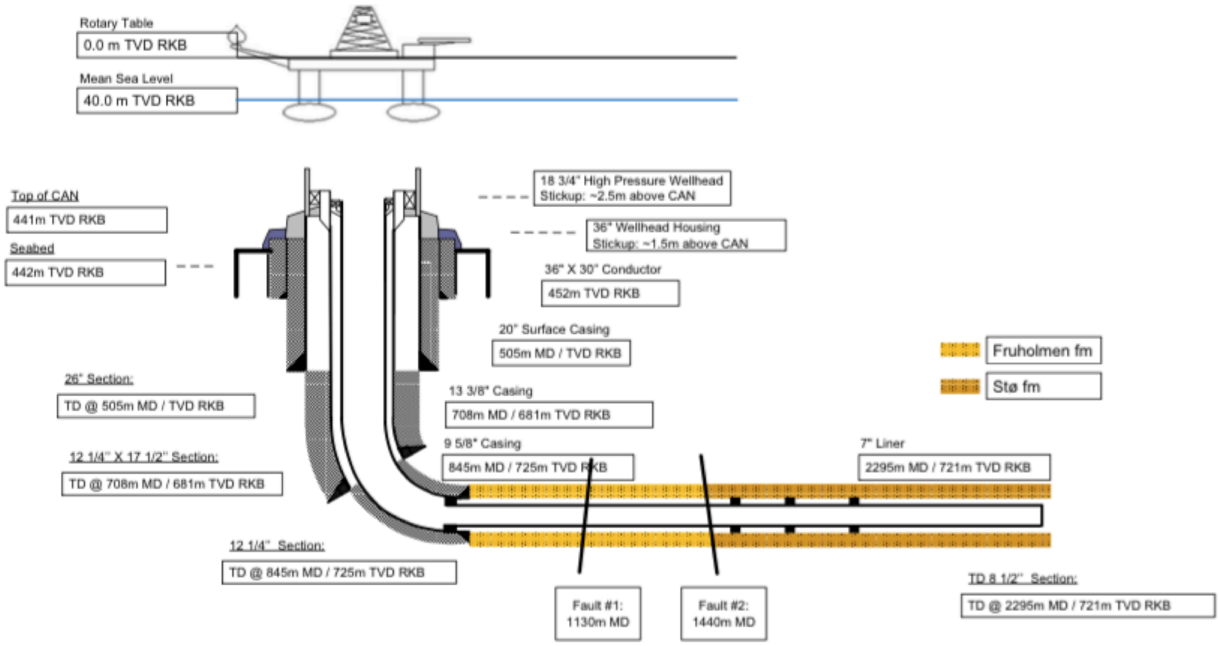

Figure 3.1: Well Schematic of Wisting Central II (Trauner et al. 2015).

being. The Wisting Central II well design is therefore an adequate template, or reference, for the new horizontal injection well on the field. Naturally, some changes had to be made, as there is an essential difference between an appraisal well and an injection well.

3.1 Well barriers

A well barrier is an object that prevents unintentional flow of hydrocarbons from a source to surface, and cross flow from one reservoir to another. The barrier is therefore required to have both lateral and vertical sealing, which is verified through various methods depending on the type of well barrier. The difference between a well barrier and a well barrier element is that a well barrier is as mentioned able to prevent unintentional flow, while a well barrier element cannot prevent unintentional flow across itself (Crumpton 2018).

Well barrier elements are divided into two; normally open and normally closed WBE's (well barrier elements). A normally open WBE is a well barrier that under normal conditions is letting fluid flow through, but is closed either automatically or manually when the well integrity is impaired. A normally closed WBE is a well barrier that is permanently closed, with no purpose of being intentionally opened, e.g. cemented liner (Crumpton 2018).

The barriers are normally categorised as primary well barriers and secondary well barriers, as the NORSOK requirement is to have minimum two verified well barriers at all times, but tertiary well barriers is also a category. A primary well barrier is the first object, or barrier, that prevents unintentional flow. A secondary barrier is the second object to prevent flow if the primary barrier fails. Naturally, the tertiary well barrier is the third object to prevent unintentional flow, in case both the primary and secondary well barriers fail (Crumpton 2018). As mentioned, the requirement is minimum two well barriers at all times, and this is illustrated in Figure 3.2 and Figure 3.3 where only primary and secondary barriers are highlighted and mentioned. This method of showing the barriers is the type of method that is normally practiced by the industry.

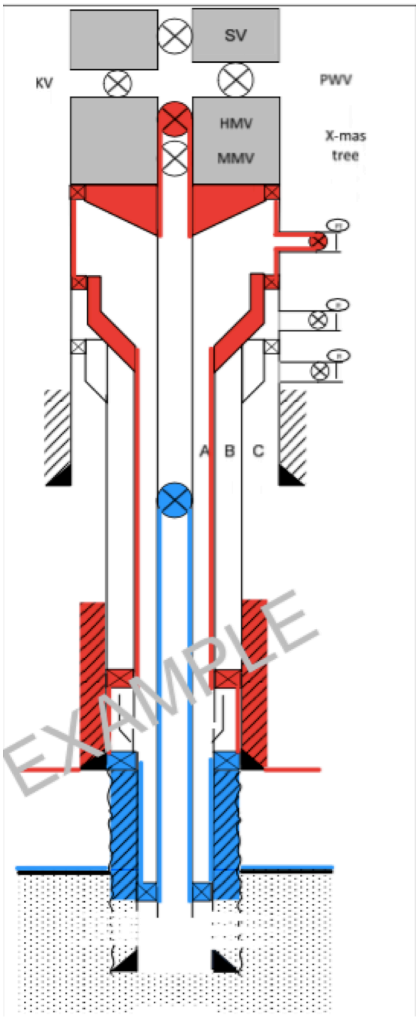

Figure 3.2: Well barrier schematic example of an injection well (NORSOK Standard D-010 2013, p.80).

The injection well barrier design correlates well with the NORSOK Standard D-010's WBS (well barrier schematic) example, which is shown in Figure 3.2. The figure shows the primary well barriers in blue, and the secondary well barriers in red. The NORSOK Standard D-010 (2013) primary well barriers are:

- *in-situ formation,*
- *production packer,*
- *liner cement,*
- *production liner,*
- *liner hanger packer,*
- *completion string, and*
- *DHSV (downhole safety valve)/control line.*

As can be seen in Figure 3.3, the primary well barriers (in blue) are the same for the Wisting injection well. There are some differences between the NORSOK example and the Wisting well, as the Wisting injector is designed for matrix injection. There will not be any perforations in the Wisting water injector, and therefore the last section of the well (8 ½" section) will be an open hole completion. However, this does not have any affect on the well barriers. The liner hanger packer is the only well barrier that is not mentioned in the Wisting Shut in Draft, although it is a valid well barrier also in the Wisting injector. The production liner will be run into the reservoir, and the injection packer will be set in the reservoir, in accordance with the NORSOK Standard D-010 (2013), "*Design requirements: Production packer to be set below cap rock*".

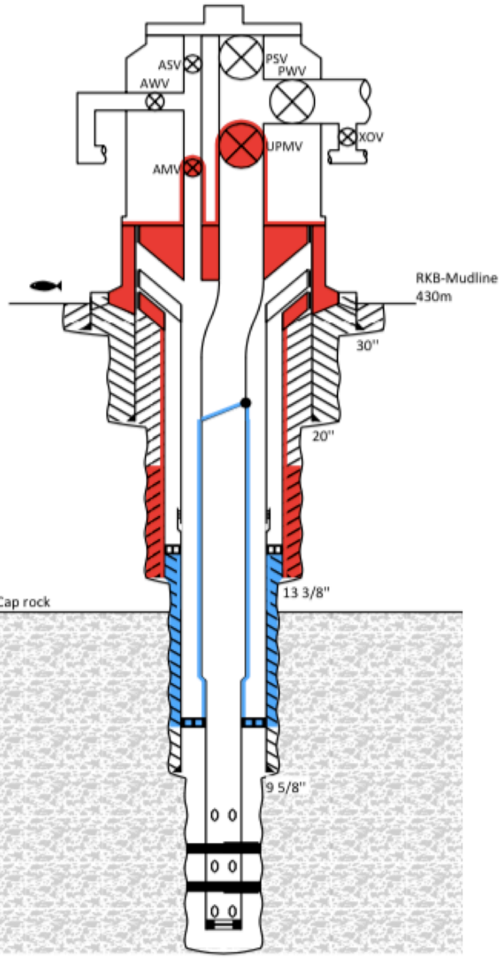

Figure 3.3: Wisting water injector well barrier schematic (Kamsvåg 2019a).

The primary well barriers in the Wisting injector will all be qualified after installation, and there will be continuous monitoring of the elements that are possible to monitor. The DHSV and control lines will be inflow tested right after the installation, and later there will be periodic inflow testing, as well as monitoring of the control line pressure (Kamsvåg 2019a). The tubing, injection packer and liner will be pressure tested to a predetermined pressure. Afterwards, the A-annulus will be continuously monitored. A formation test, job performance or a bond log will be performed on the injection liner cement to verify it as a well barrier element. The liner cement is not accessible for monitoring, but in case of suspicion of impaired well integrity, it is possible to run a new bond log. The cap rock is qualified by obtaining the minimum stress from a geomechanical model, and could be possible to monitor by mircoseismic monitoring (Kamsvåg 2019a).

The secondary well barriers that can be seen in the NORSOK Standard D-010 (2013) example (Figure 3.2) are:

- *in-situ formation,*
- *intermediate casing cement,*
- *intermediate casing,*
- *tie-back packer,*
- *tie-back production casing,*
- *production liner hanger with seal assembly,*
- *wellhead (A-annulus valve),*
- *tubing hanger (body seals),*
- *wellhead (WH/XMT Connector),*
- *tubing hanger (neck seal), and*
- *surface tree.*

The secondary well barriers on the Wisting injection well (in red) are approximately the same. A tie-back is not necessarily required in the injection well as the 13 3/8" casing is strong enough to withstand the injection pressure it will be exposed to if there should occur a leak in the production tubing. Vidar Krone (2019) explained that the 13 3/8" casing will act as the production casing, but a tie-back will be considered if the hole cleaning proves to be inadequate above the 9 5/8" liner due to too low flow rate when drilling the 8 ½" section. Even so, the optional tie-back has been included in the Wisting water injector well barrier schematic (Figure 3.3), but unlike the NORSOK example, the tie-back is not defined as a well barrier. The tie-back casing is assumed to have pressure communication with B-annulus by not using seals and ports immediately below the casing hanger. The in-situ formation is not specifically mentioned in the Wisting draft, or outlined in the figure, but it still acts as a secondary well barrier element. The subsea production tree, tubing hanger, wellhead and casing will be qualified by pressure testing to a predetermined pressure, while the production casing cement has to be qualified through a formation test, job performance or bond log (Kamsvåg 2019a). The downstream pressure in the subsea production tree and the A-annulus pressure, which is in contact with the tubing hanger, casing hanger and production casing, will be continuously monitored. The wellhead integrity could also be determined by monitoring the A-annulus, or by external observation. Monitoring of the production casing cement is not accessible; it can only be verified through bond logs (Kamsvåg 2019a).

3.2 Casings

The well is drilled in several sections, with various casing strings lowered and cemented in place in the different sections. As the well gets deeper, the diameter of the wellbore, as well as the casing strings, decreases. A properly cemented casing can be, as mentioned in the previous section, either a primary or secondary barrier. The cement prevents formation fluid

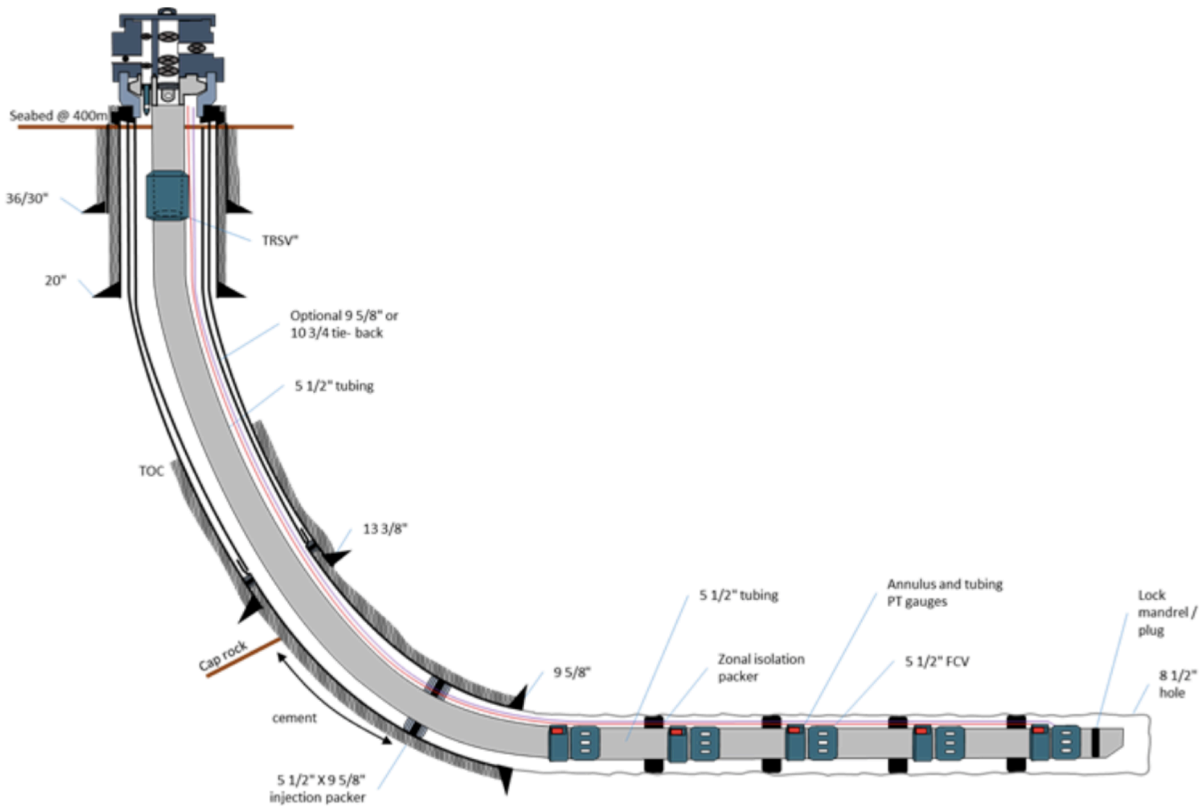

Figure 3.4: Wisting water injector well design (OMV (Norge) AS 2018e).

and pressure from migrating through the annulus to surface, or to another formation layer. The cement also strengthens the casing and provides stability to the wellbore wall (Crumpton 2018).

As can be seen in Figure 3.4, the injection well will be drilled in five sections. The top-hole section will be a 40” hole with a CAN (Conductor Anchor Node) that has a pre-installed 36” conductor casing (OMV (Norge) AS 2018e). The surface casing will be a 20” casing in a 26” hole, and in the intermediate section there will be drilled a 17 ½” hole with a 13 3/8” production casing. This section (17 ½”) will reach to right above the top of the reservoir, which means that the casing shoe will be set in the Fuglen formation as this is a solid claystone formation that provides sufficient support (OMV (Norge) AS 2018e). The surface casing will be cemented to surface, while the TOC (top of cement) of the production casing will be at least 30 m MD (measured depth) above the casing shoe if verified by bonding logs, in accordance with NORSOK Standard D-010 (2013). For the last cased section, a 12 ¼" hole will be drilled, and a 9 5/8" (typical P110, 53.5 #) production liner will be installed. The liner will be set in the reservoir (Stø/ Nordmela), and the injection packer (5 ½" x 9 5/8") will be set deep, in the reservoir. The liner will be fully cemented up to the liner hanger in the cap rock, and verified by bond logs. This will provide a minimum length of 30m MD above top reservoir, in which the 9 5/8" liner cement fulfils the NORSOK requirement:

> "*Actual cement length for a qualified WBE shall be:*
>
> *a. above potential source of inflow/reservoir;*
>
> *b. 50 m MD verified by displacement calculations or 30 m MD when verified by bonding logs. The formation integrity shall exceed the maximum expected pressure at the base of the interval.*
>
> *c. 2 x 30 m MD verified by bonding logs when the same casing cement will be a part of the primary and secondary well barrier.*
>
> *d. The formation integrity shall exceed the maximum expected pressure at the base of each interval.*
>
> *e. For wells with injection pressure exceeding the formation integrity at the cap rock: The cement length shall extend from the upper most injection point to 30 m MD above top reservoir verified by bonding logs."*
>
> (NORSOK Standard D-010 2013, p. 179).

There is no requirement of logging the cement if the cement is not categorized as "critical cement". The cement can then be displaced as stated under 6. e) in NORSOK D-010 p.178, 200 m MD above the source of inflow, and is verified by 100% displacement efficiency and by executing a FIT (formation integrity test). If however, the cement is classified as "critical cement" or the cement job has been performed without 100% displacement efficiency, or if a cement sheath shorter than 200 m MD is desired, the cement sheath has to be verified by bond logs in conformance with points 3. and 4. at page 179 in the NORSOK Standard D-010. Nevertheless, it can be of great advantage to log the cement behind the casing to be able to perform an effective P&A operation at a later stage. If the cement behind the casing is logged, it makes it possible to set a deep barrier by placing a plug in the casing for intervention or temporary abandonment, or it is possible to set a cement plug inside the casing for permanent abandonment.

The last section of the well is a horizontal 8 ½” open hole section. This is as mentioned due to the planned matrix injection instead of a perforated fractured injection. The target of this section is the lower section of the Stø reservoir, in the oil or water zone, e.g. as low as possible in the reservoir (OMV (Norge) AS 2018e).

As Figure 3.4 shows, an optional 9 5/8”, or 10 ¾”, tie-back has also been taken into account in the well design. However, as mentioned, a decision of whether or not a tie-back is required has not yet been made.

3.3 Completion

According to the NORSOK Standard D-010 (2013), the water injector (WI) completion is required to be designed to prevent out of zone injection (OOZI). This means that the injection fluid is to be kept within the target zone, which is the reservoir. It is also required to plan the injection point at a depth at which the injection fluid is unable to fracture the cap rock or leak from the reservoir during injection with maximum injection pressure (NORSOK Standard D-010 2013). The well is therefore placed as deep as possible in the reservoir, to get it as far away from the cap rock as possible.

During matrix injection, the fluid flow is from the well, and through the naturally existing pores and pore throats in the formation. Such an injection method requires a highly permeable formation, which is the case on Wisting. During a shut-in of an injection well, some of the fluid could come in return, bringing solids with it. This is called a cross-flow. To minimize the amount of solids entering the wellbore during shut-ins, sand screens could be installed. Stand-alone screens are assumed to be the most effective, but the sanding potential has not been completely determined yet (OMV (Norge) AS 2018e). Due to the sanding risk uncertainties, simpler designs, such as a pre-drilled liner (PDL), are still considered as a possibility. To improve the injection profile along the wellbore, ICD/AICD (Inflow Control Device/Autonomous Inflow Control Device) screens are weighed against single screens. Still, it is important to be able to inject with higher pressure/flow rate in a single zone for stimulation purposes (OMV (Norge) AS 2018e).

A C&P (cased and perforated) completion has also been evaluated, but as matrix injection has been proven to be the optimal injection solution, a cemented and perforated liner design has been put aside (OMV (Norge) AS 2018e).

Annular zonal isolation is required between the different injection points, to be able to control the injection interval along the horizontal open hole section. Without any isolation, the injection fluid will flow in the least resistant direction, i.e. along the well, and not into the formation in the desired injection interval. It is assumed that water swellable packers will fulfil this requirement (OMV (Norge) AS 2018e).

The upper completion comprises of flow control and gauge assemblies, zonal isolation packers, injection packer, DHSV, injection tubing, and well completion material. By controlling the outflow from the well, the barrier qualified flow control valve (FCV) (5 ½” OD (outer diameter) and minimum 4.31” ID (inner diameter)) prevents the water from going all into one fracture, and rather sends it into several smaller thermal fractures along the entire interval, optimizing matrix injection (Baker Hughes, a GE Company 2019c; OMV (Norge) AS 2018e). Without the FCV, the weakest point along the injection interval will fracture. As mentioned, this will result in one single fracture, and the flow will propagate this fracture, as it will be weaker than the rest of the formation. In other words, it will be more difficult to create new fractures than to propagate the already existing one. Another purpose of the flow control valve is to facilitate hydraulic interventions in zones from FPSO, and it makes it possible to open contingency zones later in well life. It can be either an on-off valve or a sliding sleeve valve that can provide choking. Each zone in the horizontal, open hole section will include pressure and temperature gauges that will maintain control of both tubing and annulus by continuous measuring. The gauges are also able to detect damaged components in the upper completion, as well as the lower completion (OMV (Norge) AS 2018e).

The zonal isolation packers will be equipped with a cable feed through them so that the packers still can be used for zonal isolation despite the flow control assemblies in-between. The injection packer is designed to provide a seal between the tubing and the liner, and to prevent communication between the formation and the annulus above the packer (NORSOK Standard D-010 2013). The optimal placement of the injection packer is inside the 9 5/8” liner, below the cap rock-reservoir boundary (OMV (Norge) AS 2018e). The packer is set as deep as possible in the reservoir to gain as much pressure difference between the packer and the cap rock. By placing the packer at this depth, the highest possible injection pressure is achieved:

$$
\begin{aligned}
&Max.\,injection\ pressure \\
&\qquad = pressure@cap\ rock \\
&\qquad + hydrostatic\ pressure\ between\ cap\ rock\ and\ packer
\end{aligned}
$$

When deciding the depth of the packer, a plot with pressure (bar) and depth (m TVD) is used. The plot normally consists of one curve for the reservoir pressure, one curve for the minimum horizontal stress, and one curve for the fracture pressure. First, the fracture pressure (bar) is calculated from the fracture gradient, ρ (sg), at different given depths, D (m TVD):

$$FP = 0.0981 * \rho * D$$

Secondly, the minimum horizontal stress, $\sigma_{h,min}$ (bar) is calculated, often as a percentage of the fracture pressure:

$$\sigma_{h,min} = \% * FP$$

And finally, the reservoir pressure is extrapolated:

$$P_{bottom} = 0.0981 * \nabla_{pore} * D_{bottom}$$

Where ∇_{pore} is the reservoir pore pressure gradient (sg), and D_{bottom} is the depth at the bottom of the reservoir (m TVD). And:

$$P_{top} = 0.0981 * \nabla_{pore} * D_{bottom} - \nabla_{oil/gas} * (D_{bottom} - D_{top})$$

Where $\nabla_{oil/gas}$ is the oil/gas gradient (sg), and D_{top} is the depth at the top of the reservoir. When all these values are acquired or calculated, the fracture pressure, minimum horizontal stress, and reservoir pressure curves can be inserted in the plot (Aasen 2018). In Figure 3.5, the fracture pressure curve is replaced by a fracture closure pressure curve, as this well is an injector, and not a producer. The minimum horizontal stress curve usually has lower values than the fracture closure pressure curve, and the reservoir pressure curve will intersect with the two other curves at some point. "*If there is a leak through the production casing just below the production packer, the formation needs sufficient strength to withstand this pressure*" (Aasen 2018).

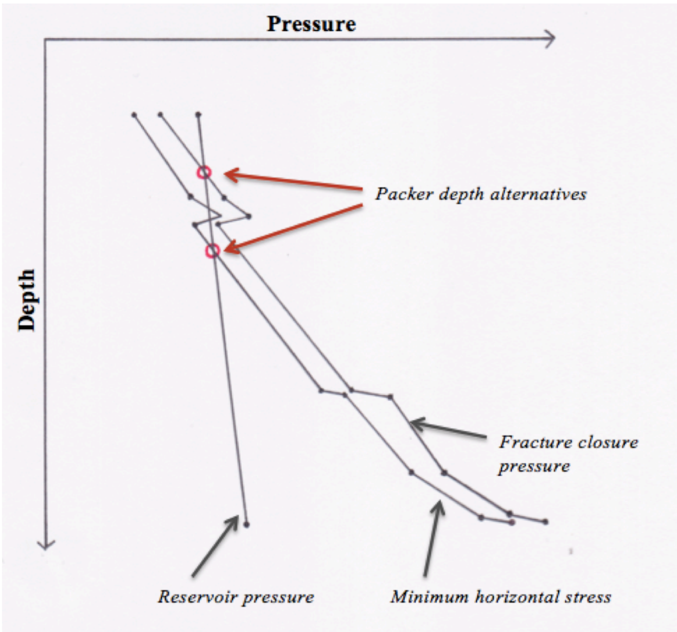

Figure 3.5: Example of packer placement depth (based on Aasen 2018).

The packer placement depends on the limiting formation strength value; either the minimum horizontal stress or the fracturing closure stress, marked with red circles on the figure (Aasen 2018).

During a meeting 3 April 2019, Trygve explained the difference between an injector and a producer, and how the depth of the packer is determined. For a production well it possible to determine the depth of the packer by identifying and comparing the fracture pressure in the formation (plus a safety factor), and the maximum production pressure. For an injection well on the other hand, another approach is to identify and compare the fracture closure pressure (plus a safety factor), and the desired injection pressure.

The DHSV is a tubing retrievable safety valve (TRSV) that will be controlled from surface, and it features the possibility for lock-open and installation of an insert valve in case of failure during a periodic test. The injection tubing will be either a 5 ½" or 5" tubing, where the lower part might require more erosion-corrosion resistant material than the upper part of the tubing due to the risk of more wear and tear close to the injection point (OMV (Norge) AS 2018e).

Trygve Kamsvåg (2019b) confirmed that the lower and upper completion will be installed in one run, and not in two which is a more conventional method. To be able to run the lower and upper completion together, a vertical Christmas tree (VXMT) is required. The horizontal Christmas tree (HXMT) has the tubing hanger is installed inside, which means that the XMT has to be installed prior to the completion tubing, and thereby requiring the lower and upper completion to be installed in two runs. When the completion has been installed with a VXMT in one run, and the FCVs have been closed, a glass plug set (and tested) inside the tubing is the only barrier needed to maintain well integrity while washing the tubing and displacing the fluid. It is desired to control the injection pressure of several water injection subsea installations with the same pressure safety valve (PSV) at surface. That makes the distance from surface to the WI furthest away very long. This extensive distance limits the tubing diameter due to friction, which also results in pressure loss, and is the reason for choosing a 5 - 5 ½" tubing without screens rather than a 3 ½" tubing with screens. An automated choke control has to be installed in every WI to be able to control the injection from one PSV at surface. The automated choke control can choke back the flow, depending on the allowable injection pressure in each well.

3.3.1 Well intervention and workover

A well intervention operation, also called workover operation, is an operation that is carried out in a well that has been active (producing/injecting) for some time. Not all downhole equipment has the ability to last through the whole life of well. Monitoring or replacement of equipment might be required after some time. During an intervention, the required tools are inserted in the well to conduct these types of maintenance and remedial work (Schlumberger Limited 2019f).

It is important to plan ahead when designing the completion of a well so that it is adapted for both interventions/workovers and P&A (plug and abandonment) in the future. Several measures can be made as a part of the completion design to improve the chances of a successful intervention, in addition to make it a cheaper operation (Bellarby 2009). Especially subsea wells are costly to enter, and as this injection well is a subsea well, it is beneficial to include later well life interventions in the completion design evaluation. Intervention operations that could be relevant for this injection well are data acquisition (cased hole formation logs, downhole sampling), integrity monitoring and repair (equipment measuring annulus pressures), tubing replacement, and so on (Bellarby 2009).

3.3.2 Fully cemented liner vs. non-cemented liner

It is natural to conclude that there is one significant difference in the injector design that will be affected by the quality of the cement job, the injection packer placement. The presented injector design is naturally based on a successful cement job, which means that a fully cemented liner will result in a deep-set packer, placed in the reservoir as shown in Figure 3.6. If however, all the cement for some reason should be lost, the natural conclusion is that the placement of the packer has to be changed. The injection point will no longer be in the reservoir, but in the cap rock just below the 13 3/8" casing shoe. That means that the packer will not be an accepted barrier when placed in the reservoir. If the liner should fail above the packer, there would only be one barrier above it, which deviates from the NORSOK D-010 requirement of minimum two well barriers in hydrocarbon formations. As explained by Jan Aage Aasen (2019), the injection packer would in this case have to be placed in the 13 3/8" production casing due to the risk of leakage across a packer placed in the 9 5/8" without the support of cement behind the liner. Without the support of the cement, the change in pressure and temperature resulting from injection vs. shut-in would cause axial and radial movement of

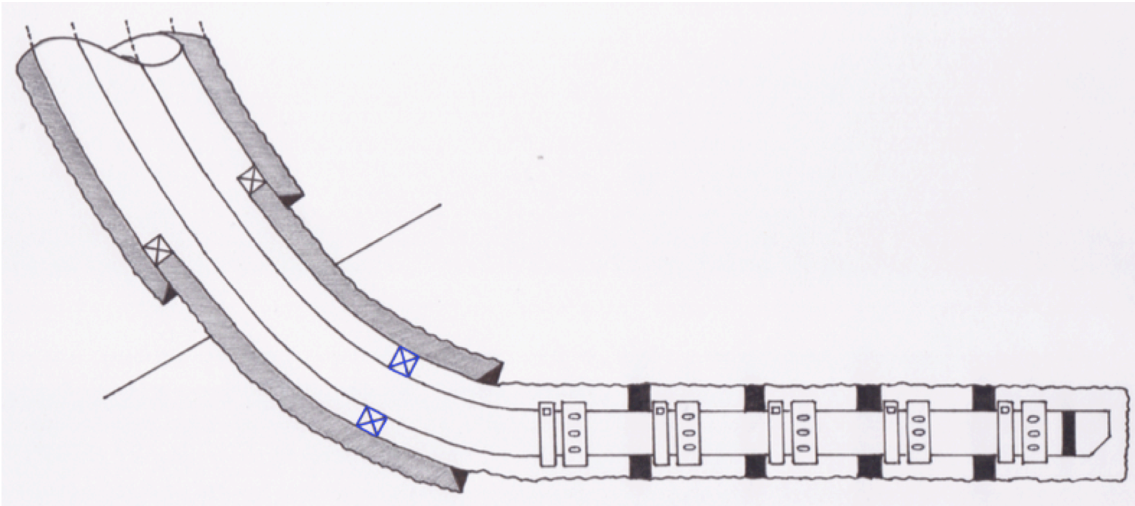

Figure 3.6: Completion design with a fully cemented liner (based on OMV (Norge) AS 2018e).

the packer, and it could cause a leak across the packer. Re-placement of the packer would result in a larger sized packer than anticipated.

However, Trygve Kamsvåg (2019b) explains that in this case, the 13 3/8” casing shoe will be set deep enough to withstand reservoir pressure at the shoe. The 13 3/8” casing shoe is planned to be set as close to the reservoir as possible, but with a safety margin to ensure that it does not enter the reservoir. In addition to this, the liner hanger packer has to be qualified as a barrier, and as there already is very low pressure and temperature in the reservoir, there will be no drastic changes causing axial and radial movement of the packer. It is therefore possible to set the production packer in the 9 5/8” liner despite impaired or no cement outside the liner. This water injector is one of the injectors where it is desired to set the injection packer deep to be able to increase the injection pressure. In the case of a deep-set injection packer, there has to be cement in the annulus from the packer depth and 30 m MD above the reservoir. If no cement is present in the annulus, it is still possible to set the packer in the 9 5/8” liner at the same depth, but the injection pressure has to be significantly reduced. Nonetheless, due to the lost injection pressure, there will no longer be any reason for placing the packer at this depth. Therefore, the packer will in this case most likely be placed in the 9 5/8” liner, adjacent to the 13 3/8” casing shoe as shown in Figure 3.7, as this will be the depth of the injection point with a non-cemented liner.

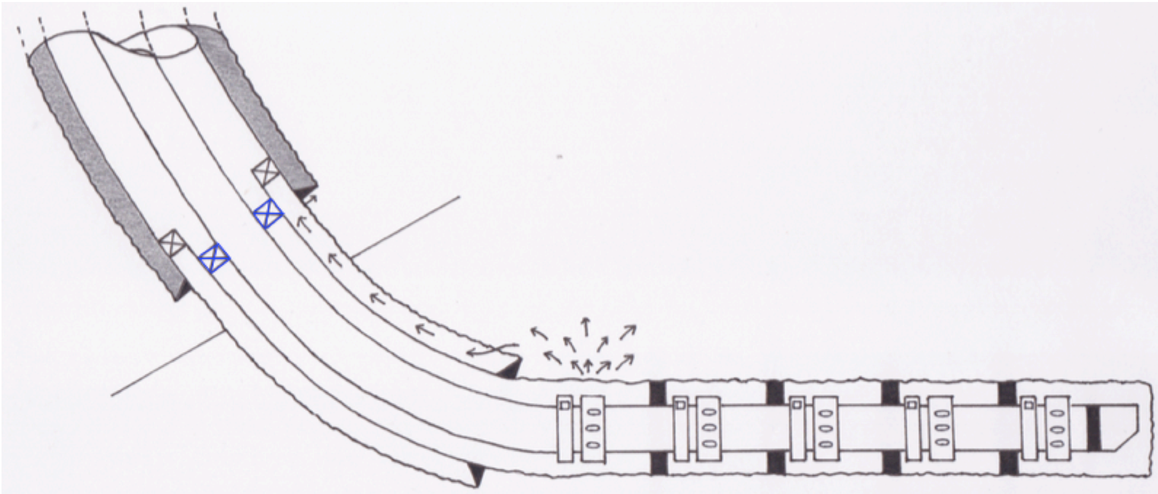

Figure 3.7: Completion design with a non-cemented liner (based on OMV (Norge) AS 2018e).

For an injector where injection pressure reduction is unacceptable, the solution could be barrier qualified stage collars in the 9 5/8” liner to get a new attempt on achieving a good cement job. Nonetheless, the chances of achieving a good cement job through stage cementing after a primary cementing job has failed are very small, but it is a solution to consider as a plan B or C. Such stage collars were used on the Grane field, but a successful cement job was never achieved and it resulted in a non-cemented 9 5/8” liner (Kamsvåg 2019b).

Of course, the most optimal solution is to achieve a successful primary cement job, and the Wisting field offers good prospects for this. The design includes a very short 9 5/8” liner, which enables it to be rotated during cementation, and the ECD (equivalent circulation density) will not get too high, even with high circulation rates. In addition to this, the TVD difference between the 13 3/8” casing shoe and the 9 5/8” liner shoe is small, which means that there will not be a very high pressure on the 9 5/8” liner shoe, according to Kamsvåg (2019b). It is possible to decrease the density of the cement, or to cement with CML (cement mortar lining), if the injector is drilled through a loss zone and loss of cement is of real concern, but this has not yet been considered by OMV (Norge) AS. The water injector trajectory is planned to avoid any visible faults and fractured zones, and the seismic images of the field are of high quality, reducing the risk of drilling into unknown fault zones. One challenge was flagged during the packer placement in Wisting Central II; getting enough weight down on the packer in a nearly horizontal section (Trauner et al. 2016). This challenge is greater for the fully cemented liner scenario as the packer is closer to the horizontal section, but as it is a lessons learned from a previous completed well, the challenge will be dealt with prior to the completion of the water injector.

3.4 Plug and abandonment

Every well will come to an end at some point. The length of the life of well varies, depending on the volume of reserve in the reservoirs, the production/injection performance of the well, and so on. As mentioned in chapter 3, there exist both temporary P&A and permanent P&A, and it is an advantage to plan and design the well for later life operations, such as P&A.

3.4.1 Temporary P&A

Temporary abandonment is defined as a well that is abandoned for a maximum of 3 years without continuous monitoring or for as long as needed with continuous monitoring and periodic testing. The BOP (blowout preventer) or XMT (Christmas tree), depending on the current operation, have to be pressure/function tested prior to a temporary abandonment (NORSOK Standard D-010 2013). The reason for abandonment can be many, e.g. a more important operation (skidding rig to another slot), well problems, planned ST (sidetrack) at a later time, waiting for production rig, waiting for a workover, and so on (Aleksandersen & Reinås 2018). All documentation of the planned temporary plug and abandoned well has to be in order prior to the P&A operation; planned temporary barriers, duration of the abandonment, and future plans for the well (NORSOK Standard D-010 2013). If the well that is temporarily abandoned has been landed in a hydrocarbon bearing formation, i.e. in a formation with potential source of inflow, the requirement is to plug it with two barriers. On the other hand, if the well has been landed in a formation with no risk of inflow, and with normal pressure, only one barrier is required (Aleksandersen & Reinås 2018). The barriers should be of a material that will ensure barrier integrity for twice the planned abandonment period, as well as make it possible to safely re-enter the abandoned well (Aleksandersen & Reinås 2018). According to the NORSOK regulations, five requirements have to be fulfilled prior to a temporary P&A operation:

"*Prior to temporary abandonment, the following requirements shall be fulfilled:*

a) Production/injection packer and tubing hanger is pressure tested.

b) Tubing is pressure tested.

c) The DHSV is closed and pressure/function tested.

d) All valves in the subsea tree are pressure/function tested and are closed.

e) *For wells with horizontal subsea tree, the tubing hanger crown plug(s) is pressure tested.*

All valves shall be verified to have zero leak rate or plug(s) shall be installed to compensate for leaking valves."

(NORSOK Standard D-010 2013, p. 85).

The Wisting injector will be landed in the Stø reservoir, a hydrocarbon bearing formation. Even though it is a water injector and the immediate area around the well mainly consists of injected water, the well is required to be plugged with two barriers (primary and secondary barrier). And as the XMT is a vertical Christmas tree, it is optional to either leave the tubing in the well or pull it out (Aleksandersen & Reinås 2018; Saasen et al. 2013). According to Trygve Kamsvåg (2019b), closed FCVs are qualified deep-set barriers, and it is therefore not necessary to set a deep-set mechanical plug. In addition to the FCVs, a DHSV will be installed in the tubing string. The DHSV is also barrier qualified when closed, providing a second primary barrier option. As long as either the FCVs or the DHSV are closed, the primary well barrier requirement is fulfilled. The main differences in the two scenarios (fully cemented and non-cemented liner) are the depth of the cement sheath and the in-situ formation as well barriers, as can be seen in Figure 3.8 and Figure 3.9. The figures are based on the NORSOK Standard D-010 (2013) WBS example on page 86, and the completion of the injector well, depending on a successful cement job or not.

The primary barriers in Figure 3.8 are: in-situ formation (cap rock and reservoir boundary), minimum 30 m MD logged 9 5/8" liner cement, injection packer placed in reservoir, completion string (between injection packer and DHSV), and closed DHSV. The secondary barriers are: in-situ formation, minimum 30 m MD logged 13 3/8" casing cement, 13 3/8" casing, 13 3/8" casing hanger, annulus access valve, tubing hanger, XMT valves/connector, and XMT body.

The primary barriers in Figure 3.9 are: in-situ formation (cap rock), minimum 30 m MD logged 13 3/8" casing cement (up to liner hanger), liner hanger, liner (between injection packer and liner hanger), injection packer at 13 3/8" casing shoe depth, completion string (between injection packer and DHSV), and closed DHSV. The secondary barriers in Figure 3.9 are: in-situ formation, minimum 30 m MD logged 13 3/8" casing cement, 13 3/8" casing, 13 3/8" casing hanger, annulus access valve, tubing hanger, XMT valves/connector, and XMT body.

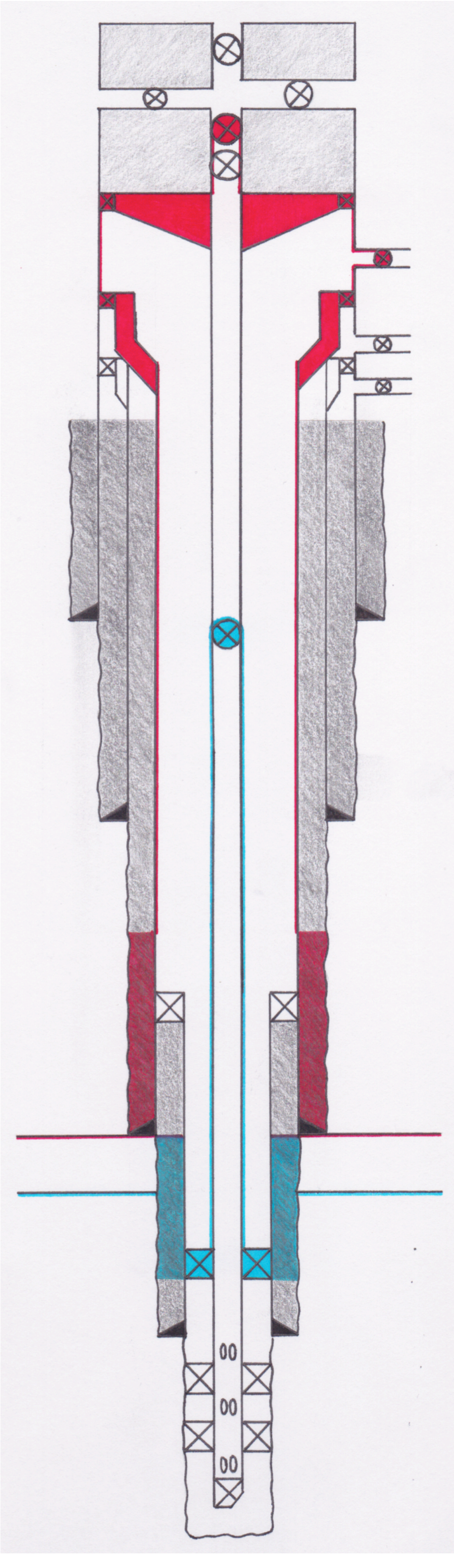

Figure 3.8: Temporary abandonment of a fully cemented liner (based on NORSOK Standard D-010 2013; OMV (Norge) AS 2018e).

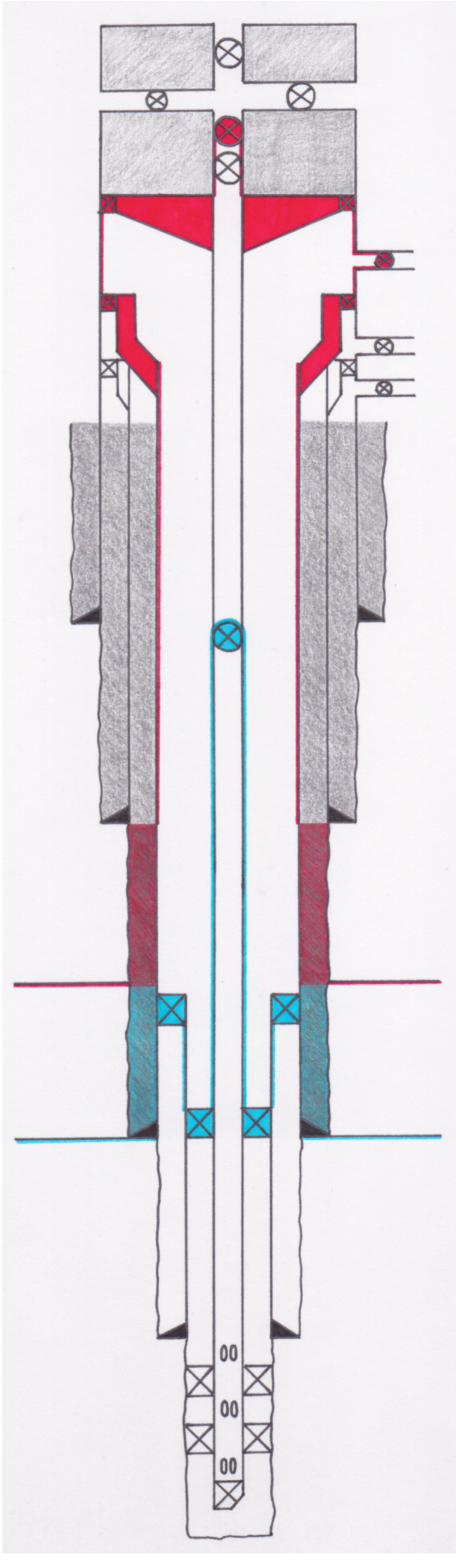

Figure 3.9: Temporary abandonment of a non-cemented liner (based on NORSOK Standard D-010 2013; OMV (Norge) AS 2018e).

As the Wisting injector will be a subsea well, it is a requirement to protect the top of the injector from external loads on seabed. Also, due to the subsea factor, it is not possible to continuously monitor or routinely test the well barriers unless it is tied back to a production facility. Therefore it might not be possible to abandon the Wisting injector for more than a maximum of three years, and the well has to be frequently inspected (at least once a year) using a ROV (remotely operated vehicle) (NORSOK Standard D-010 2013; Petroleum Safety Authority 2019).

3.4.2 Permanent P&A

Permanent plug and abandonment is an abandonment operation with an eternal perspective. In other words, the well is plugged in a manner that will seal it off both horizontally and vertically, as an extension of an adjacent impermeable in-situ formation, for an eternity with no plans of being re-entered (Aleksandersen & Reinås 2018; NORSOK Standard D-010 2013). That means that the plug design has to include foreseeable effects and processes, so that it can withstand any expected pressures and temperature-effects that it may encounter.

The plugging activities should include a primary well barrier, secondary well barrier, cross-flow well barrier, or open hole to surface well barrier, or a combination of these (NORSOK Standard D-010 2013). The primary and secondary well barriers have been explained in chapter 3.1 "Well barriers". A cross-flow well barrier is a barrier that prevents flow from one reservoir to another, or from one formation to another. However, two or more reservoir zones with the same pressure is not required to have a cross-flow barrier isolating them from each other. These zones can be regarded as one, and a primary and a secondary well barrier can be set above the shallowest reservoir zone, isolating the flow from the surface or seabed. If the casings have been cut and pulled from the well, an open hole to surface well barrier is required to permanently isolate flow from an exposed formation to the surface or seabed (NORSOK Standard D-010 2013).

As mentioned in the previous part (chapter 3.4.1), only one barrier is required between the surface and an exposed formation without hydrocarbons (e.g. dry exploration wells or water injectors), while if it is a reservoir still containing hydrocarbons and/or has flow potential, two well barriers are required (Aleksandersen & Reinås 2018). NORSOK defines the required characteristics of a permanent well barrier:

> *"A permanent well barrier should have the following characteristics:*
>
> *a) provide long term integrity (eternal perspective);*

b) *impermeable;*
c) *non-shrinking;*
d) *able to withstand mechanical loads/impact;*
e) *resistant to chemicals/ substances (H_2S, CO_2 and hydrocarbons);*
f) *ensure bonding to steel;*
g) *not harmful to the steel tubulars integrity.*

(NORSOK Standard D-010 2013, p. 96).

When a well is permanently abandoned, the optimal scenario is to retrieve or remove everything from the well activities that is disrupting the surrounding environment. All equipment that can be an obstruction to, or that can create a conflict with, other marine activities in the future has to be removed. The wellhead and the casings should preferably be cut and removed below the seabed to prevent anything sticking up from the seabed in the future. However, it can be possible to leave, and optionally cover, the wellhead of a subsea (deep water) installation (NORSOK Standard D-010 2013).

According to Aleksandersen and Reinås (2018), the permanent P&A operational procedure begins by identifying potential inflow and testing the XMT. When this is completed, the well can be prepared for plug and abandonment. The well is filled with heavy fluid, also called kill fluid, increasing the pressure in the well to overcome the pore pressure in the formation to prevent inflow of reservoir fluids. As long as the kill fluid stays inside the well and maintains the pressure from the hydrostatic column, it is defined as a well barrier, and there is no need of pressure control equipment at surface/seabed. But two well barriers are needed to remove the XMT and replacing it with a BOP. Therefore, a bridge plug has to be installed prior to the switch, and when the BOP has been installed, the bridge plug can be removed again. Next, the tubing (upper completion) is pulled, and the wellbore is cleaned to enable logging, cutting and pulling of the casings. Finally, cement plug(s) are set in the well, the upper part of the surface casing and the WH are removed, the hole is covered, and the well can be abandoned.

Due to the shallow reservoir on Wisting, the pressure and temperature is already very low. And when the Wisting water injector is ready for permanent plug and abandonment, the pressure in the well will be normal and hopefully the whole oil reserve has been extracted from the reservoir. In addition to this, as briefly mentioned earlier, the reservoir is slightly tilted due to the faults, resulting in the hydrocarbons moving away from the injector placed at the lower part of the reservoir. Therefore, the water injector should in theory only be required to be plugged with one well barrier between the normal-pressurized Stø formation and the seabed. However, for safety reasons, the well will still be plugged with both primary and secondary well barriers.

According to Trygve Kamsvåg (2019b), placing a cement plug (internal well barrier) inside the 9 5/8” liner can solve the well barrier requirement, as long as an interval of minimum 30 m MD of the cement in the annulus behind the liner has been logged and verified as a well barrier (external well barrier). Logging the cement in the annulus behind the 9 5/8” liner and the 13 3/8” casing will enable a more effective P&A operation. The cement plug has to cover the whole external well barrier interval, i.e. minimum the 30 m MD of logged cement, to fulfil the NORSOK Standard D-010 acceptance criteria. In addition to this, the cement sheath has to have a length of 50 m MD above the shallowest source of inflow.

If the liner does not have the outside support of cement, the critical point of inflow will be at the depth of the 13 3/8” casing shoe. In this case, the cement plug has to be placed above this critical point (i.e. inside the 13 3/8” casing), adjacent to the compatible and impermeable cap rock, Fuglen formation, as the liner tubular itself is not an accepted well barrier without the support of cement. Without the cement sheath in the annulus, the liner is defined as a previously described well barrier element (NORSOK Standard D-010 2013).

The plan is to fill the whole well with cement, from the injection packer in the liner and almost to the top, qualifying it as two barriers instead of only one. According to the NORSOK Standard D-010 (2013), the requirement in this case is a cement plug of 100 m MD as a primary barrier, and a cement plug of 50 m MD as a secondary barrier, placed directly on top of the previous plug. Hence the design of the two figures on the next page. The cement plug acting as both primary and secondary barrier will be tagged and pressure-tested for verification. There has to be an un-cemented section on the top (minimum 5 m below seabed) to make room for cutting the casings and the wellhead (Aleksandersen & Reinås 2018). As the well will have an inclination of 70-80° as it intersects with the top of the reservoir, a mechanical plug inside the tubing string might not be necessary to prevent the cement from being pumped inside the tubing. All the FCVs will be closed before a permanent P&A operation, and will create the deep-set barrier. It might be necessary with a shallow-set mechanical plug if the well is not completely filled with cement. The permanent barrier design for the two different scenarios can be seen in the figures on the next page (Figure 3.10 and Figure 3.11), based on Table 24 on page 181 in NORSOK Standard D-010 (2013) and on the completion of the injector well, depending on a successful cement job or not.

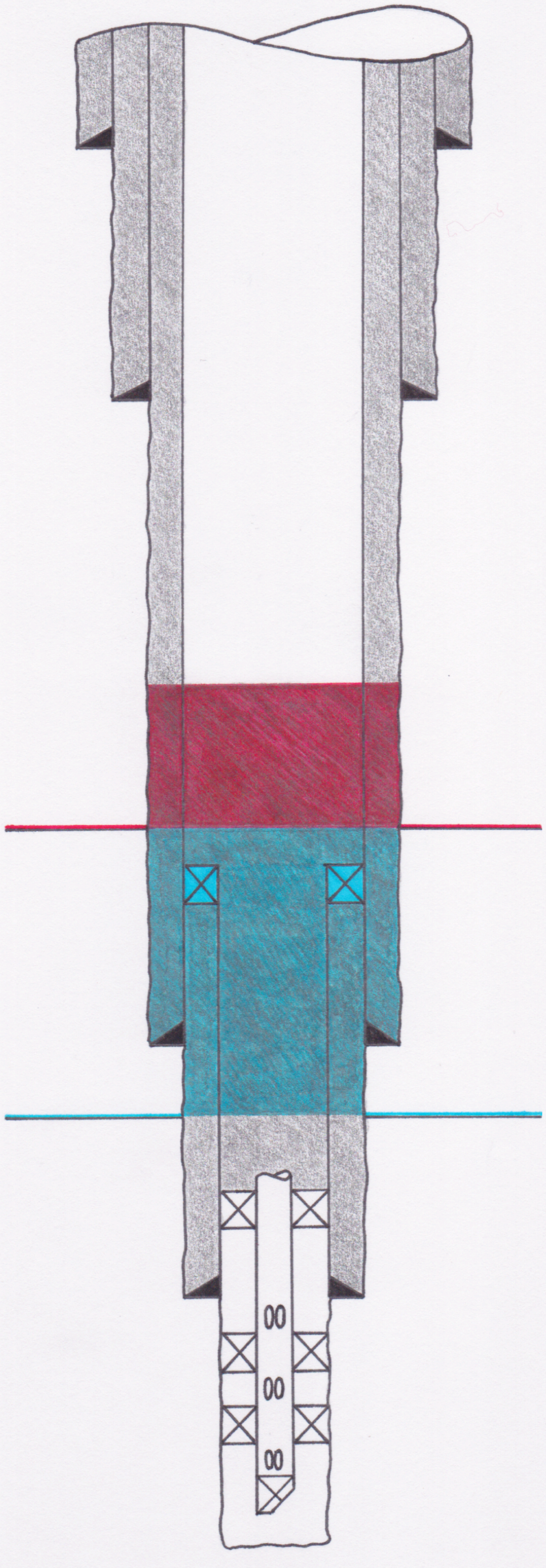

Figure 3.10: Permanent abandonment of a fully cemented liner (based on NORSOK Standard D-010 2013; OMV (Norge) AS 2018e).

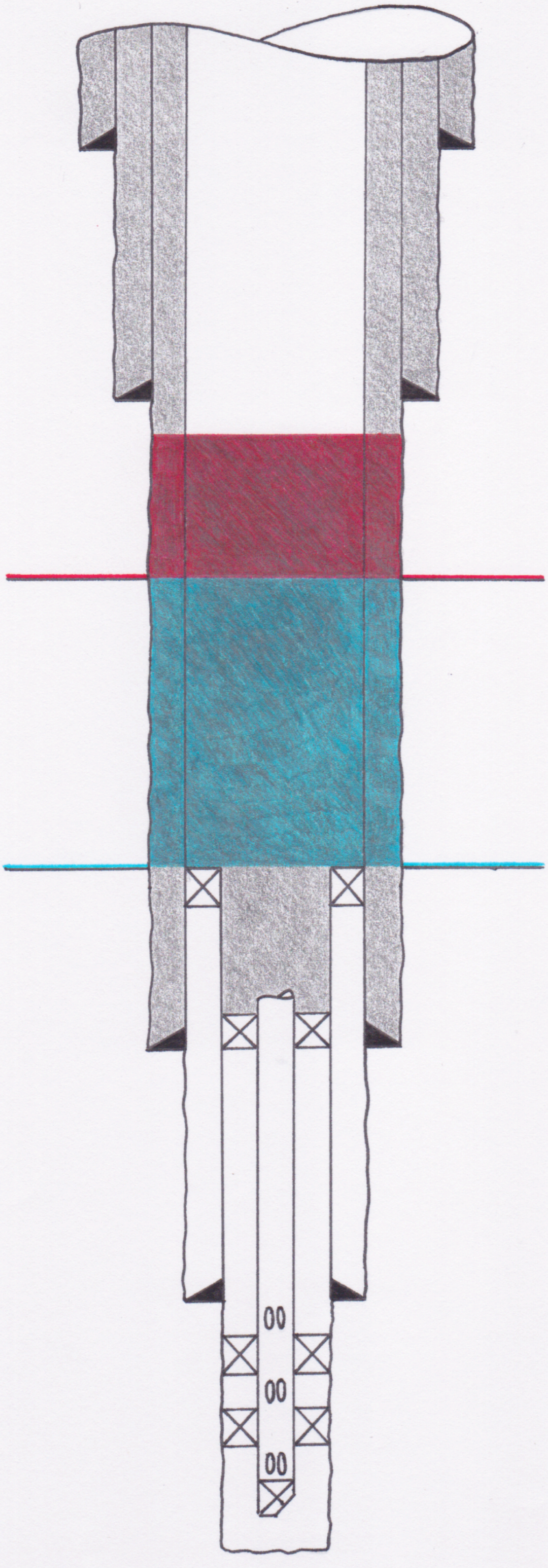

Figure 3.11: Permanent abandonment of a non-cemented liner (based on NORSOK Standard D-010 2013; OMV (Norge) AS 2018e).

4. Cement

The cementing operations of a well can be divided into two groups: primary cementing and secondary cementing. A primary cementing operation is the cementing of a liner or casing for zonal isolation and prevention of hydrocarbon migration. The cement sheath also serves as a support for the casing while preventing external corrosion on the casing (DeBruijn et al. 2016; Schlumberger Limited 2019c). A secondary cementing operation is another expression for remedial cementing, which is a repair of primary cementing problems. A primary cementing damage can be a result of a poor cement job or of long-term production/injection effects on the cement sheath (DeBruijn et al. 2016; Schlumberger Limited 2019d). The main focus will be on primary cementing, but secondary cementing will also be studied, as primary cementing damage might become an issue at some point during the life of the well.

4.1 Primary cementing

The primary cementing operation consists of drilling and setting the casing in the wellbore, pumping and placing the cement in the annulus between the casing and formation, waiting for the cement to set, and finally log and evaluate the resulting cement quality (DeBruijn et al. 2016). For the cement to properly set, the wellbore has to be entirely clean of drilling fluids and mud cake. Drilling fluids in the wellbore can contaminate the cement slurry, change the cement properties, and thereby reduce the cement quality. Mud cake can prevent the proper bonding between the cement and the formation, which at a later stage can lead to a channel available for fluid flow. Due to the problems that could be caused by the drilling fluid and mud cake, the wellbore is thoroughly cleaned before pumping cement. The clean out is done by circulating a calculated, or simulated, volume of drilling fluid, and by pumping chemical washes and spacer fluids (DeBruijn et al. 2016). A spacer fluid is a fluid that is pumped into the wellbore between a fluid with a special purpose (cement) and another fluid (drilling fluid) that should not be mixed together. The spacer fluid is compatible with both fluids, and assures that the special purpose fluid is not contaminated with an incompatible fluid (Schlumberger 2019e).

For a clean out to be executed thoroughly, it is important that the borehole is as on-gauge as possible, i.e. no washouts that make the borehole irregular and/or enlarged. An irregular and enlarged borehole makes it more difficult to clean as drilling fluid is easily contained in the washouts (DeBruijn et al. 2016). This can as mentioned, contaminate the cement slurry. However, as the Wisting reservoir was deeply buried before the uplift, it is more solid than other formations might be at this depth, and a washout should not be a problem. Normally, a caliper tool is used to determine the borehole geometry. The caliper tool contains several "arms" that move along the borehole wall as the tool is lowered into the hole, logging the diameter of the wellbore. Knowing the diameter of the wellbore is important to determine the volume of cement required to cement the casing-wellbore annulus. It is also important to identify prospective lost circulation zones.

When the wellbore has been cleaned, the cement is ready to be pumped and placed in the annulus. A plug, called the bottom plug, is placed and pumped in front of the cement slurry to separate the cement from the wellbore fluids until it lands on a landing collar at the bottom of the well (Schlumberger Limited 2019a). The bottom plug is hollow with a rupture disk on top, as shown in Figure 4.1. As the cement is pumped into the wellbore, the pressure increases and the disk in the bottom plug ruptures, allowing the cement to be pumped through the hollow plug. A solid top plug is placed and pumped into the wellbore after the cement, also preventing contamination of the cement from above. When the whole volume of cement has been pumped in place, the top plug will land on the bottom plug. An increase in pressure will verify the landing of the top plug, and the waiting for the cement to set begins (Schlumberger Limited 2019a).

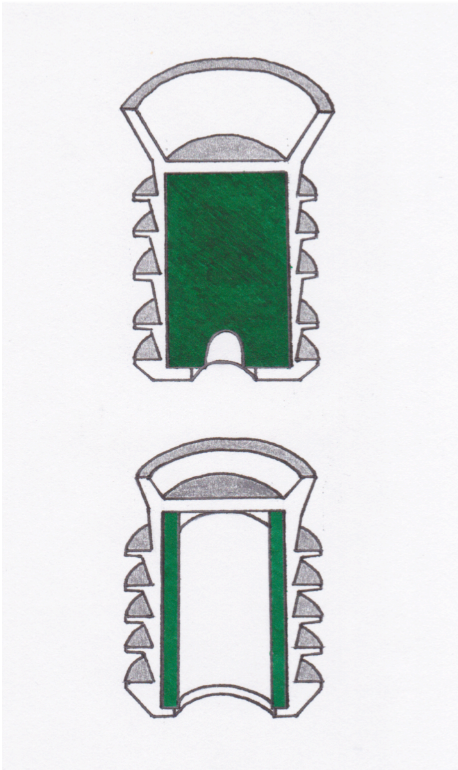

Figure 4.1: Cementing plugs (based on Schlumberger Limited 2019a).

4.1.1 Cementing the horizontal section

Cementing the liner in the horizontal section of the well is a bit more complicated than cementing the vertical sections. It is critical that the casing is as centralized in the well as possible to achieve a high quality cement job. The liner is heavy and will naturally settle at the bottom of the hole, as the buoyancy effect of the pipe in the drilling mud is not large enough to hold the pipe. Due to this, it could be challenging to displace the cement evenly around the liner. There is a risk of the liner having contact with the formation at the bottom of the horizontal section. That could result in insufficient cement, or as critical as no cement, at the bottom along that interval, which would worsen the injection efficiency. Rotation of the short liner during the cementing operation would better the cement displacement around the liner, and improve the cement job quality.

4.1.2 Schlumberger

Schlumberger has a wide selection of cement slurries, depending on the borehole conditions and environment. Many of the cement types are relevant for the Wisting water injector, but only a few of the relevant slurries have been picked out and are described below.

One of the main criteria for any cement system is fluid stability. Chemicals are added to prevent any sort of settling or free fluid separation. Schlumberger has a special laboratory test, “Fluid Loss Test”, which determines slurry resistance to screen out and filtrate through permeable zones. Depending on the application, this parameter is kept within the required range, explained by Nadya Lyapunova (2019).

Lightweight Cement Slurry

Schlumberger’s lightweight cement slurry is a type of cement slurry that has a lower density/weight than the normal cement types. Normal cement slurries usually have a density of 1.893 kg/m^3, while the lightweight slurry has a density range of 1.042 kg/m^3 to 1.558 kg/m^3 (Schlumberger 2010). With this type of cement slurry, it is possible to neglect the two-stage cement operation, and pump the primary cement in a one-stage operation. Due to the low density of the cement, it is very effective in lost circulation zones, as well as it enables long intervals with cement without losing cement due to hydrostatic pressure (Schlumberger 2010). Schlumberger’s product sheet (2010) also informs that the compressive strength and permeability properties of this lightweight slurry is “*comparable to normal cements*”, and that the slurry is “*strong enough for hydraulic fracturing treatments (...)*”, which would make it a good solution for a water injector. Nadya Lyapunova (2019) wrote that the lightweight cement slurry is easily mixable, enabling the possibility to achieve the desired cement rheology. She also specified that the main benefit with this cement slurry is the high compressive strength despite the low density.

Self-Healing Cement System

The self-healing cement system is able to heal itself if cracks or microannulus have developed in the cement sheath, and it comes in contact with any hydrocarbon fluids. Nadya Lyapunova (2019) mentioned that this self-healing cement contains a particle composition that can react (swell) in the presence of hydrocarbons (both oil and gas). In theory, it would react with the oil droplets that are left in the produced water that is re-injected, if the oil droplets come in contact with the cement. However, as Nadya Lyapunova (2019) further explains, if the oil is well dispersed in the water and the cement sheath is water-wet, the probability of the oil coming in contact with the cement becomes smaller. According to Schlumberger's product sheet of the self-healing cement system (2016), it is applicable for both primary cementing and P&A, it has a low Young's modulus, which makes it more flexible, and a wide density and temperature range (1.320-1.940 kg/m^3 and 20-138°C, respectively). The cement slurry also expands as it sets, improving the cement to casing/formation bond, in addition to being easily adjusted for optimal results (Schlumberger 2016).

Flexible Cement System

The Flexible cement system is designed to withstand high mechanical stresses, which helps to maintain the cement integrity (Lyapunova 2019). This cement slurry does not normally expand as it sets, but it is possible to add additives with expandable properties to provide the expanding effect. The flexible cement is applicable for both primary cementing and P&A plugs, like the two previous cement types. Another field of application is in wells with potential for pressure and temperature variations due to e.g. injection or hydraulic fracturing (Schlumberger 2017a). The risk of cement mechanical failure is minimized due to the low Young's modulus (2.4-6.9 GPa) of the cement slurry, and the wide density and temperature range (1.500-1.940 kg/m^3 and 20-150°C, respectively). Although, a potential mechanical failure of the cement sheath can be a result of temperature and pressure changes, well completion, stimulation treatments, drilling and perforating (Schlumberger 2017a).

4.1.3 Baker Hughes GE

Baker Hughes GE, like Schlumberger, has a wide selection of cement slurries, depending on the borehole conditions and environment. Many of the cement types are relevant for the Wisting water injector, but only a few of the relevant slurry types have been picked out and are described below.

According to Antonio Bottiglieri (2019), the higher the cement content in the slurry, the lower is the capability to withstand any additional stresses. He explained that the reason for this is that the cement itself is a very brittle material. To overcome this challenge, it has become normal to replace cement with other material to increase the ductility of the cement (lower Young's modulus). Antonio Bottiglieri (2019) informs that Baker Hughes GE is using mineral fibers with higher diameter-to-length ratio, as one of the weak points of cement is the tensile strength (great resistibility in compression, but very low in tension), and this ratio will improve this parameter.

Lightweight cement

The lightweight cement slurry has a very low density, reducing the hydrostatic pressure of the cement and making it suitable for low-pressure wellbores. Nitrogen or air is often added to the slurry to provide a high-strength cement system. Other additives can also be included in the mix, optimizing the slurry for each specific operation and wellbore environment. This lightweight cement enables the conventional two-stage operation to be performed in only one stage, saving both time and money (Baker Hughes, a GE company 2019d). According to Antonio Bottiglieri (2019), this type of cement is a good option in case of losses.

Foam cement

According to Antonio Bottiglieri (2019), the foam cement is an energized fluid with dinitrogen (N_2). The very low-density property of the cement helps lower the lost circulation risks and it protects against shallow gas and water flow. This saves the operator both time and money (Baker Hughes, a GE company 2019b). Like the lightweight cement, the foam cement can also be displaced in one stage, but the foam cement also expands as it sets in the annulus. This expanding property of the cement improves the cement bond to the casing and the formation, reducing the risk of any channels in the cement. Antonio Bottiglieri (2019) explains that foamed cement improves the cement placement in low-pressure environment, and that this slurry improves mechanical properties, such as Young's modulus and Poisson's ratio. He also emphasizes that without the right experience and expertise, it can be risky to perform a cementing operation with foam cement.

Self-healing cement

The self-healing cement has the characteristic of healing itself when it gets in contact with hydrocarbons. If the cement job has failed or been damaged, e.g. by not achieving cement bond to either the casing or formation, or if a crack has been created over the lifetime of the well, and hydrocarbons are present in the crack, the cement sheath will swell to prevent further hydrocarbon flow. This self-healing property enables the cement to seal cracks up to 0.009" (Baker Hughes, a GE company 2019a).

4.2 Cement evaluation

4.2.1 Schlumberger

Cement Bond Logging Tool

The Cement Bond Logging tool is used for evaluation of cement quality, determination of zone isolation and location of top of cement. The tool measures the bond between the casing and the cement. The bonding quality provided by a sonic tool is presented in a cement bond log (CBL), where low millivolts/high decibel attenuation indicates good quality bonding, and vice versa. The cement bonding quality is easily affected by how effective the mud removal has been. The compressive strength of the cement and changes in temperature and pressure after cementing also has an effect on the cement bonding (Schlumberger 2007). The Cement Bond Logging Tool is unable to provide information about the bonding between cement and formation, but when paired with a variable-density log (VDL), the combination of the two logs gives a complete image of the cement bonding quality (Schlumberger 2007).

PowerFlex and PowerEcho Annular Barrier Evaluation Services

The PowerFlex and PowerEcho Services are applicable for operations such as drilling, cementing, well integrity, cut-and-pull operations. During cementing operations, the PowerFlex and PowerEcho assist the cement placement design analysis (cement contamination and properties) and the centralization plan (Schlumberger 2017b). The services also improve the cement placement quality and pipe centralization, makes micro annulus diagnosis and leak path analysis for well integrity. Both PowerFlex and PowerEcho can operate in a wide selection of casing sizes (up to 22" and thickness up to 1"), and evaluate cement condition and bonding for any cement. For the time being, it is planned to use a P110

53.5# liner. A liner of this grade and nominal weight will have an approximate thickness of 0.545”, which puts it within the thickness operational range. But only the PowerFlex Service is able to evaluate lightweight cement slurries, foamed cement and contaminated cement. This service is also the best option of the two for cement placement quality characterization and identifying micro annulus. The reason for the PowerFlex being the better option in many cases is that the PowerFlex service includes all the features that the PowerEcho service offers (acoustic impedance, cement bond to casing, internal radius, casing thickness), in addition to several other features (flexural attenuation, variable-density log (VDL) of annulus waveform, solid-liquid-gas (SLG) map of annulus material, hydraulic communication map, and rugosity image) (Schlumberger 2017b). According to Amit Govil (2019), both PowerFlex and PowerEcho give information about the bonding between cement and casing, but neither gives information about the bonding between cement and formation.

Isolation Scanner

The Isolation Scanner combines the pulse-echo technique with a new ultrasonic technique (flexural wave imaging). The ultrasonic tool is composed of one transmitter and two receivers, where the results are combined with the pulse-echo measurements. The tool has a radially measurement coverage, enabling identification of any channels (as narrow as approximately 3 cm) in the cement and confirmation of zonal isolation effectiveness (Schlumberger 2011). Amit Govil (2019) explains that channels narrower than 3 cm can become an issue. It could result in pressure build-up behind or in-between the casing. However, he also explains that it is possible for the channel to expand if there is flow present in it, making it easier detectible by the logging equipment. The Isolation Scanner is able to measure all types of cement. Amit Govil (2019) writes that in recent times, using the combination of PulseEcho and Flexural measurements makes it possible to distinguish between cement and formation, which has proven to be very important information for P&A applications. One of the main goals is to “*provide an image of the material immediately behind the casing*” (Schlumberger 2011), where the output is a “*SLG map displaying the most likely material behind the casing*” (Schlumberger 2011). The combination of the two techniques provides information about the annular environment, and it also makes it possible to differentiate low-density solids from liquids, and lightweight or contaminated cements from liquids. The Isolation Scanner can identify corrosion and drilling-induced wear on the casing, the borehole shape, and it can provide information about the centralization percentage (100% - perfect centering, 0% - fully eccentered) (Schlumberger 2011). To be able to determine the quality of cement to formation bond, the Isolation Scanner is often run as a combination with CBL (Cement Bond Log) and VDL, according to Amit Govil (2019).

4.2.2 Baker Hughes GE

Segmented Bond Tool™ (SBT™)

The Segmented Bond Tool™ is a pad-tool where transmitters and receivers are placed on six motorized arms of the tool, and the pads are in contact with the casing. The tool is able to confirm hydraulic isolation by identifying channels in the cement that could lead to an unacceptable seal by measuring the cement bond in "*six angular segments around the casing*" (Baker Hughes Incorporated 2014). The SBT provides measurements related to the compressive strength of the material outside the casing using acoustic waves that are transmitted and received by the pads. This provides a radial resolution of 360°, and a vertical resolution of 3". It analyses the cement bond both to the casing and to the formation, and it can provide accurate measurements in up to 1" thick casings. If the P110 53.5 # liner will be used, with approximately 0.545" thick walls, the SBT would provide good measurements for this section. The SBT is insensitive to moderate tool eccentering and is unaffected by fast formations and temperature and pressure variations (Baker Hughes Incorporated 2014). Even if the tool should become slightly decentralized, the pads would still be in contact with the casing, and the effect of the decentralization is reduced or even negligible, explained by Morten Bethuelsen (2019). The measurements are plotted in real time, enabling the measurements to be available and displayed in the logging mode. The SBT also provides a variable-density log (VDL) to identify the bond between the cement and the formation, which is important to determine if a micro annulus forming and creating a pathway up to the cap rock (Baker Hughes Incorporated 2014). The SBT™ Seal advanced cement bond analysis service provides colour coded seal intervals on the log to make it easier to read, which enables a quick verification of the cement quality and placement. It is also able to obtain data from casing sizes up to 24", which is promising for a P&A operation (Baker Hughes Incorporated 2015).

ChannelView™ Well Integrity Detection Service

The ChannelView™ Well Integrity Detection Service is a combination of SBT and RPM (Reservoir Performance Monitor™) in the same run. The objective of the ChannelView is to find water flow with the RPM tool in cement channels identified by the SBT tool. The Hydrolog™ service of the RPM service is used together with the SBT to identify cement channels. The result is used to determine if the FlowShot™ service is needed to confirm water in the channels. The FlowShot is able to acquire the velocity of the water, if present (Baker Hughes Incorporated n.d). The combination of these two evaluation services reduces the time spent in the well and identifies cement channels accurately. The RPM service is able to quantify the water velocity in both cement channels and behind the casing. The ChannelView service is also used for "*production/injection profiling in multiple string completions*" (Baker Hughes Incorporated n.d.). Morten Bethuelsen (2019) explained that the ChannelView service is not restricted by high inclination, and that the measurements will be of the same quality in a highly deviated well as in a well with low to none deviation. However, the SBT tool has to be very centralized in the well to acquire high quality data as it only tolerates moderate tool eccentering.

Integrity eXplorer™ Cement Evaluation Service

The Integrity eXplorer™ (INTeX) cement evaluation service is a name for bond logging using the INTeX tool. It provides accurate information about the cement bond acquired from the tool, regardless of the type of fluid in the well. The INTeX tool is run together with the VDL tool to verify the bond between cement and formation, and is independent of presence of fluid in the well (Baker Hughes, a GE company 2017). Electromagnetic-acoustic transducer sensor technology enables the INTeX cement evaluation service to evaluate lightweight cement slurries, even foam cement slurries. The INTeX tool provides a direct measurement of the shear strength of the material on the outside of the casing. Using the electromagnetic-acoustic transducer sensors, waves are induced along the casing for measurement of shear strength. Simultaneously the casing is "pulsing" for detection of material behind the casing that has not bonded properly to the casing. This "movement" also gives an indication of micro annulus, explained by Morten Bethuelsen (2019). The INTeX tool has the same type of pads as the SBT, with transmitters and receivers on six motorized arms, putting the tool in contact with the casing. This will, as mentioned, keep the tool in contact with the casing regardless if the tool is slightly de-centralized, minimalizing the effect of tool eccentering. The pad design also enables the INTeX tool to provide accurate measurements in highly tortuous and deviated wells (Baker Hughes, a GE company 2017).

4.3 Secondary cementing

Secondary cementing is as mentioned a remedial cementing operation that is initiated if the primary cement job has failed. A primary cement job is considered as failed if there are micro annulus or channels in or along the cement sheath, or if the volume of the cement is inadequate. The primary cement job can fail either during the cementing operation, or the failure can develop over time. For a cement sheath with micro annulus or channels, the usual treatment is cement squeeze. Cement squeeze repairs the primary cement job by squeezing, or forcing, cement into the channels and micro annulus that could be a pathway for hydrocarbons, or injection water in this case, in the primary cement sheath (Schlumberger Limited 2019b). For a cement sheath where the volume of the set cement is inadequate, it is often used stage cementing (Kamsvåg 2019b). Stage cementing can also be used for primary cementing jobs if it is not possible to e.g. perform a normal lead and tail cement operation, but will in this case only be used if the primary cementing job fails, thus it becomes remedial cementing. If it should be considered that stage cementing might be necessary for this injector, stage collars have to be installed in the casing string prior to the installation of the casing. In this case the stage collars would be installed in the liner, and they would have to be barrier qualified to be able to optimize the injection. An example of barrier qualified stage collars is Archer's Cflex® with a two-stage permanent lock system, which is certified as gas tight under ISO 14310 V0 (Archer 2019).

5. Water Injection

"*To economically optimize water-injection projects, the pressure difference between the injection well and the production well has to be maximized*" (Clemens et al. 2017).

In many cases, injection wells are converted production wells. This means that when a production well does not produce at the desired rate and volume anymore, the production is shut down, and the well is recompleted into an injection well. In other cases, new wells are drilled with the solely purpose of injection from the start. These wells are drilled the same way as the production wells, but the completion of the wells is different.

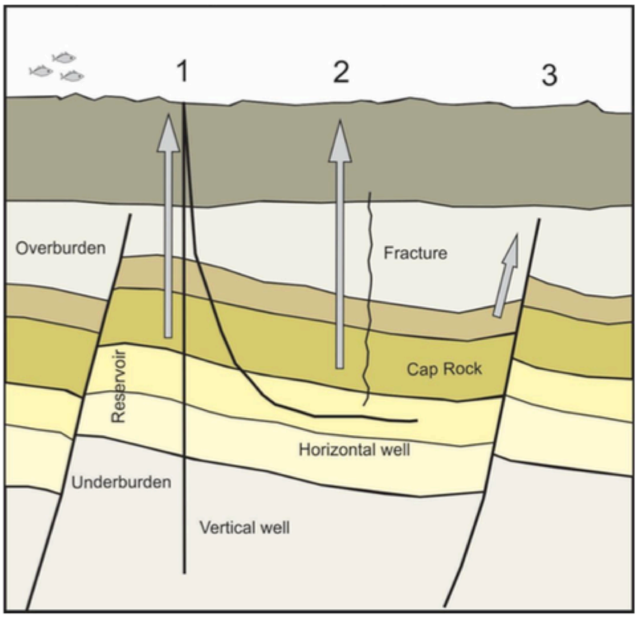

Figure 5.1: Three main challenges regarding cap rock integrity – (1) Leakage along the well, (2) Stress contrast and (3) Faulted/damaged zone (Stueland 2018).

As mentioned, the Wisting Central II well was drilled through both known and unknown faults. The injection well will be placed close enough to the producer to establish communication, but far enough to delay water production as much as possible. It needs to have a good distance from the gas cap, and would preferably be placed in the water zone. Unfortunately, there is a fault between the water zone and the producer, and the characteristics of the fault are unknown. So, the injector will not be drilled through any known faults, nor be drilled in proximity of a fault, due to the risk of the injection fluid disappearing into the faults instead of flowing towards the producer (OMV (Norge) AS 2018e). Regardless, this is one of the three main challenges when it comes to cap rock integrity (Figure 5.1). The first challenge is leakage along the well. Leakage along the well is the most common cause for out of zone injection, or leakage, on the NCS (Stueland 2018). This type of leakage is usually caused by poor cement jobs when cementing the casings, i.e. weak bonding between cement and casing/formation, which creates pathways for the fluid to migrate through. The second challenge is the mentioned stress contrast. The stress contrast between the reservoir and the cap rock on Wisting is almost non-existing. Trying to avoid the reservoir pressure, caused by injection, to become higher than the minimum horizontal stress of the cap rock is therefore a crucial challenge. If the reservoir pressure gets higher than this stress, it would cause a fracture to propagate into the cap rock. And, in worst-case scenario, the fracture could propagate up through the whole overburden to seabed due to the shallow depth. The third, and last, main challenge is faults and damaged zones (Stueland 2018). There is a risk of the well hitting a zone that is faulted or damaged, resulting in all the injected water going into an already existing fracture/fault, and eventually propagating that single fracture/fault instead of flowing in the desired direction.

To predict when fractures will be initiated and how they will propagate, the in-situ stress needs to be accurately characterized, usually through XLOTs (extended leak-off tests) (OMV (Norge) AS 2018c). There are different stages of pressure that affect the fracture development. These stages, or the XLOT cycle, are shown in Figure 5.2. Before the injection start-up, the bottomhole pressure (BHP) is naturally equivalent to the normal reservoir pressure (at time = 0 in Figure 5.2). The first stage after injection start-up (1) is the formation integrity test (FIT) pressure. Formation integrity is the formation's ability to withstand pressures and loads that is might encounter, and a FIT identifies the pressure at which fluid starts to force itself into the formation. The FIT is also called a limit test (LT) (OMV (Norge) AS 2018c). The leak-off pressure (2) is the pressure at which the fluid in the well starts to flow into the formation, either through interconnected pores or small fractures created by the pressure, and it is the same pressure that is used when a leak-off test (LOT) is carried out. A LOT is usually conducted first thing after a casing has been set and the casing shoe has been drilled out (Aadnøy & Looyeh 2011). The pressure will keep increasing after reaching the LOP (leak-off pressure), even though the fluid flows into the formation, however at a slightly lower rate. The friction of the fluid against the formation creates enough resistance for the pressure to increase. The pressure will increase until it reaches point 3; the fracture breakdown pressure

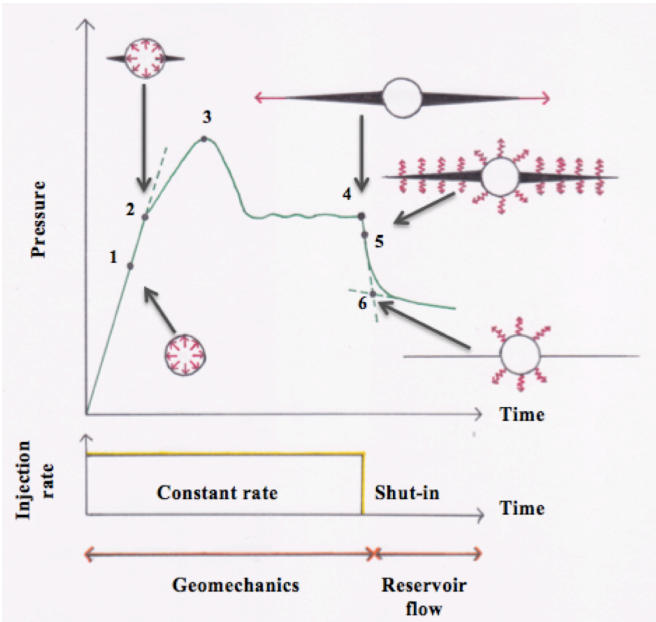

Figure 5.2: Fracture development pressures (based on Rabia, cited in Aadnøy & Looyeh 2011, p. 136; OMV (Norge) AS 2018c; PetroGem Inc. 2016).

(FBP), also called fracture initiation pressure (FIP). As the names indicate, this pressure is of a magnitude that will crack open fractures (Cheong 2016).

Fracture initiation can be identified through pressure measurements. As Figure 5.2 shows, the pressure will drop right after a fracture has been created due to less resistance from the formation. After some time, the resistance further into the formation, i.e. in the fractures, will start to build up again. When the resistance becomes high enough, the rate of the pressure drop will decrease, and the pressure will eventually even out to a constant pressure. This constant pressure is the fracture propagation pressure (FPP), shown as point 4 by Figure 5.2 (OMV (Norge) AS 2018c). By keeping the injection rate constant, the fractures will continue to propagate, keeping the BHP constant. The fractures will always propagate in the least resistant direction. The least resistant direction is in the direction of the maximum stress, which in most cases, and in the case of Wisting, are in the vertical direction (Figure 5.3). The vertical stress is greater than the horizontal stress, which means that the horizontal stress is not high enough to prevent a fracture to expand in width in the horizontal direction and length in the vertical direction. Figure 5.3 is a very simple illustration of this effect.

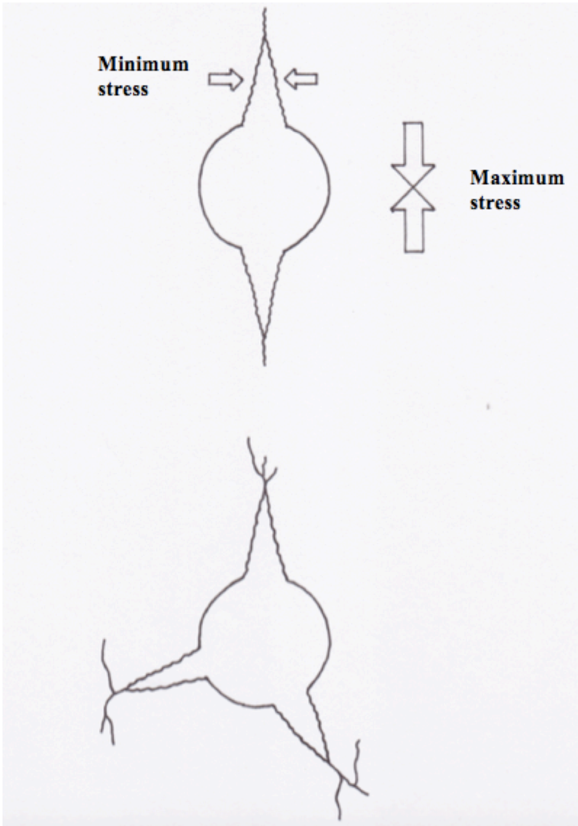

Figure 5.3: Fracture propagation (based on Cheong 2016).

Right after point 4 in Figure 5.2, the well is shut in and the injection rate becomes zero, as can be seen on the "Injection rate" diagram at bottom (Aadnøy & Looyeh 2011; OMV (Norge) AS 2018c; PetroGem Inc. 2016). The fluid is no longer being pumped into the formation, and the pressure will thereby drop instantly. The sequence between point 4 and point 5 is called the initial shut-in pressure (ISIP), or the instantaneous shut-in pressure (ISIP). When this instant pressure drop has passed, and the pressure starts to decrease at a lower rate, passing the fracture closing/closure pressure (FCP) (6), the fluid will flow back to into the well or leak off into the formation. The formation and the well will slowly return to the normal reservoir pressure and the fracture closes again (Aadnøy & Looyeh 2011; OMV (Norge) AS 2018c; PetroGem Inc. 2016).

Figure 5.2 also shows the dominant forces during the fracture development. From point 1 to 6, the dominant force is the geomechanics. The strength of the rock/formation is the force dominating the fracture development. After point 6, it is the reservoir flow that is the dominant force. It is the reservoir fluid's ability to flow through the pores and pore throats of the formation to lower pressures, levelling the pressure back to the original reservoir pressure (Cheong 2016).

> "*For wells injecting at a pressure greater than the fracture closure pressure at the injection depth, the following applies:*
>
> *a) the production packer shall be installed at a depth ensuring the injection or a casing leak below the production packer will not lead to fracturing of the cap rock or leak to shallower formation when applying maximum injection pressure (...);*
>
> *b) the casing/liner cement shall be logged and as a minimum have bonding from upper most injection point to 30 m MD above top reservoir;*
>
> *c) it shall be documented that the injection will not result in a reservoir pressure exceeding the strength of the cap rock.*"
>
> (NORSOK Standard D-010 2013, p. 64).

The first point in the cited paragraph above supports the choice of packer placement in both scenarios. The scenario with a fully cemented liner is in accordance with the second point, while the scenario with a non-cemented liner naturally is not. However, it is actually the cement job of the 13 3/8" casing that is the most critical cement job (Kamsvåg 2019b). Since the 13 3/8" casing shoe will be set as close to the top of the reservoir as possible, it will not be very critical if the 9 5/8" liner cement job has been performed poorly if the 13 3/8" casing cement job has been verified. The third point means that if OMV (Norge) AS is able to simulate an injection that at some point fractures the reservoir, and the fracture never reaches the cap rock in the simulation, it opens the possibility to inject at a pressure greater than the FCP.

The injection rate is dependent on the maximum allowable injection pressure. And the injection pressure is dependent on the formation integrity below the injection packer. As written in NORSOK Standard D-010 (2013), and cited above, the formation below the packer must have sufficient strength to withstand the injection pressure. This is to avoid any leaks and fractures to an overlying formation, or in worst case to the surface. The main concern on Wisting is exactly this. Hence the operational plan is matrix injection.

5.1 Wisting matrix injection

The Wisting water injector will re-inject produced water at some point in the future as mentioned earlier, due to the location of the field. But until the producer on Wisting starts to produce water, the injection fluid will be seawater, the cheapest and easiest available injection fluid. Seawater is so clean and free of particles that it will not plug and fracture the formation when injected at the right rate and pressure. This is matrix injection, the operation of injecting fluid into the formation, only through the pores and pore throats of the formation, without fracturing it.

The safest injection pressure during a matrix injection is, as implied in the citation above, below the fracture closing pressure.

However, as can be seen in Figure 5.2, the FCP is lower than both the fracture initiation/breakdown pressure and the fracture propagation pressure. This means that if the pressure is kept below the propagation pressure, any already existing fractures will not propagate further. The pressure can be slightly higher, resulting in a slightly higher injection rate, improving the injection efficiency. If the pressure is kept above the ISIP, and below the FPP, it is possible to exploit the pathways in any already existing fracture. The fluid reaches further into the formation without exceeding the pressure that will propagate the fractures, and the injection rate can be increased. Most importantly, the bottomhole pressure cannot exceed the minimum stress of the cap rock (Clemens et al. 2017).

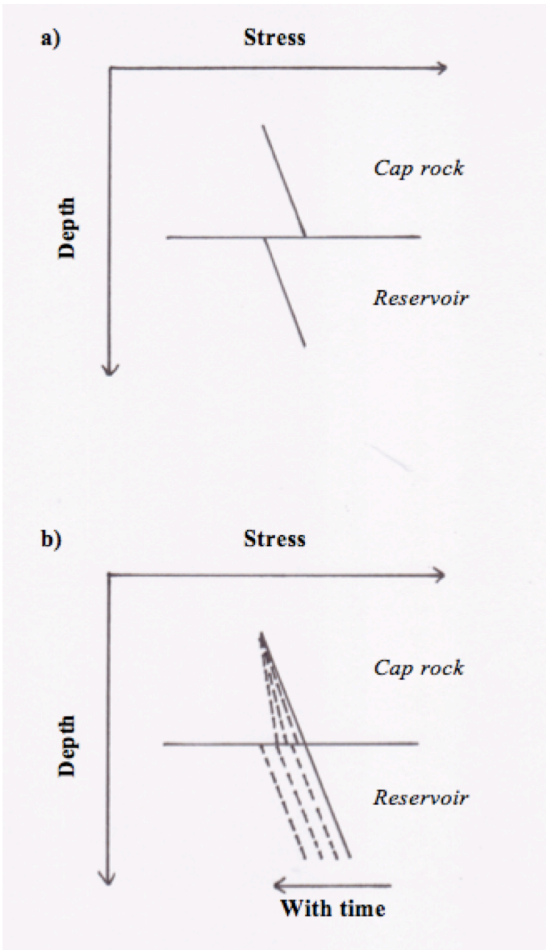

Figure 5.4: Stress contrast, a) ideal stress contrast, b) Wisting stress contrast (based on Stueland 2019).

The objective is to inject clean seawater as long as possible to cool down the reservoir as much as possible, according to Eirik Stueland (2019). The stress contrast between the cap rock and the reservoir will increase as the temperature contrast between the two formations increases. Figure 5.4 shows the stress contrast in an ideal case a) and in the Wisting case b). The ideal case is when the cap rock has a higher minimum stress than the reservoir. When the cap rock has a higher minimum stress than the reservoir, it is required a higher pressure to fracture the cap rock than the reservoir. That means that it is possible to fracture the reservoir without the risk of fracturing the cap rock. On Wisting on the other hand, the situation is slightly different. The stress contrast is almost negligible, as shown with the full line in Figure 5.4 b). This unusual case increases the risk of fracturing the cap rock significantly. But as the figure also shows, the stress contrast can be increased with time due to cooling. And this is one of the main objectives during the injection operation. As the cap rock is more compact due to the low permeability in the rock, the fluid will not enter it during matrix injection. The fluid will only flow into the reservoir, and along the top of the reservoir layer. This will result in a higher cooling effect in the reservoir than in the cap rock, and thereby the stress contrast will increase. A simulation of the temperature effect on stress will also be introduced later.

However, after a certain period of time, the producer will start to produce water from the reservoir. And as the field is located in the Barents Sea, all the produced water will have to be re-injected. The produced water will be cleaned as much as possible, but it will still contain small particles and oil droplets that cannot be separated from the injection water. These particles and oil droplets will create more friction when in contact with the formation than the seawater, and they will eventually get stuck in pores, creating even more resistance, which will lead to a build-up of the pressure. At this point, either the injection rate has to be reduced to reduce the pressure, or the reservoir will start to fracture. In other words, the skin factor will become so large that the reservoir has to be fractured to maintain the injection pressure and rate at the desired level, according to Jan Aage Aasen (2019). It is now the importance of the cooling effect comes in. If the reservoir successfully has become cooler than the cap rock, and the stress contrast has increased, it is possible to maintain the injection rate and fracture the reservoir with a lower risk for the fractures to propagate into the cap rock above. When a fracture reaches the cap rock, it will stop propagating vertically, and propagate further in the horizontal direction alongside the cap rock and reservoir boundary. With cold fluids flowing along the bottom of the cap rock, the cap rock could be cooled down faster than anticipated, which again would increase the risk of fractures propagating into the cap rock.

It is not possible to inject produced water and maintain the injection rate at the desired level without fracturing the reservoir. The objective with water injection is to improve oil recovery in a depleted reservoir, or in this case in a reservoir with already very low pressure. With an injection rate limitation, the injection operation can become insufficient and uneconomic (Clemens et al. 2017).

5.2 Fully cemented liner

When the liner is fully cemented and the cement has been verified as a barrier, the injection packer is placed as deep as possible in the reservoir. This increases the distance up to the cap rock and reservoir boundary, and thereby provides a "buffer" zone in the reservoir. The injection point is therefore at the bottom of the reservoir, 20 m TVD deeper than the cap rock, as shown in Figure 5.5. The injection rate can be maximized due to this distance, which also provides additional time to react if the pressure should exceed the strength of the reservoir and fracture it. If fracturing of the reservoir should occur, the BHP should be kept below the FCP (fracture closing pressure) to ensure that the fracture will not re-open and propagate further. However, as mentioned earlier, it is possible to inject with a higher pressure than the FCP without causing the fractures to propagate, as long as it is below the FPP.

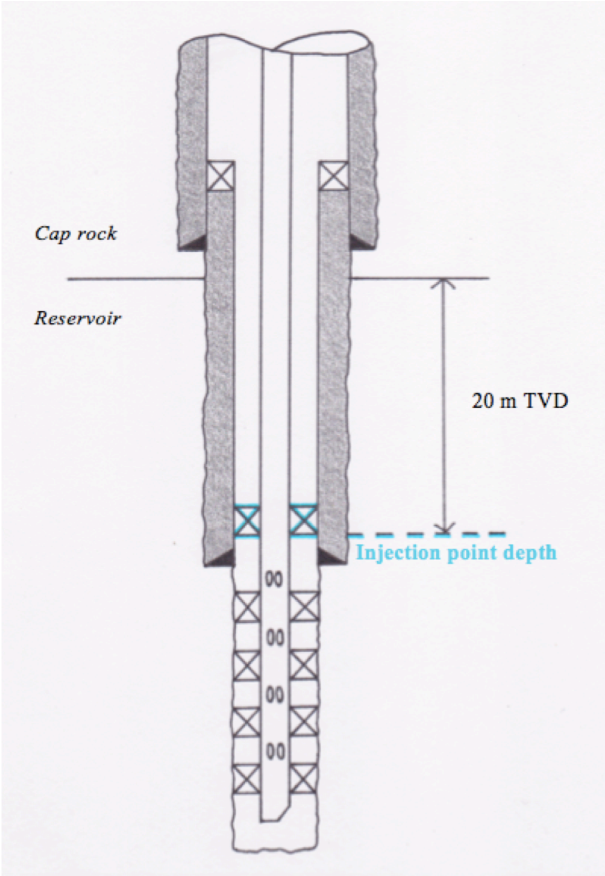

Figure 5.5: Depth of injection for a fully cemented liner (based on Kamsvåg 2019b).

Achieving a verified cemented liner will help maintain the cap rock integrity. It will in other words help mitigate any damaging of the cap rock, e.g. fracturing, fluid contamination and so on.

5.3 Non-cemented liner

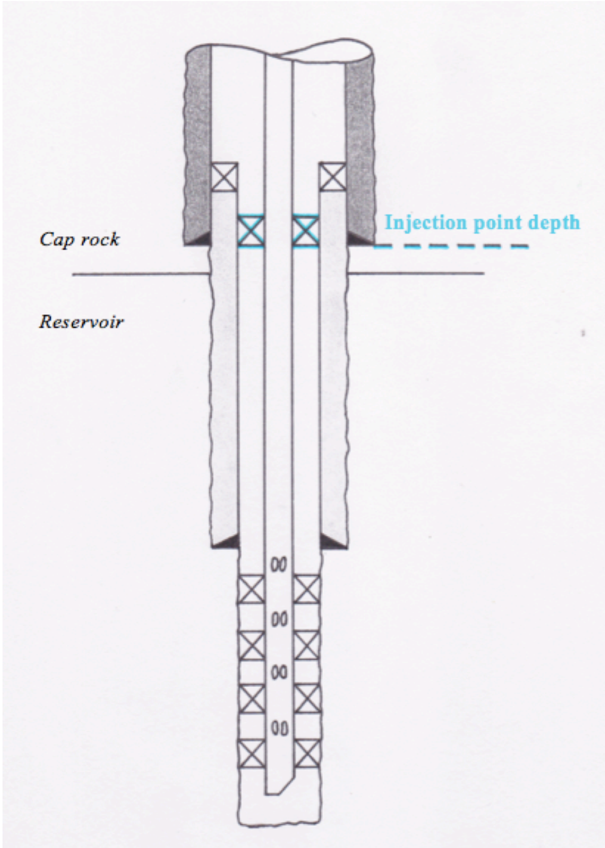

Figure 5.6: Depth of injection for a non-cemented liner (based on Kamsvåg 2019b).

When the cementation job of the liner has failed, and there is no cement in the liner annulus, the injection packer will be placed at the depth of the 13 3/8” casing shoe. In this case, there is no “buffer” zone in the reservoir. The injection point is just below the 13 3/8” shoe, which is in the cap rock (Figure 5.6). This means that the injection rate has to be significantly reduced to ensure no fractures in the cap rock. The actual injection will still be in the reservoir in the open hole section, but the injection water will find the easiest pathway to lower pressure. There will be lower pressure towards the producer due to depletion of the reservoir, and part of the fluid will therefore flow in the direction of the producer. Due to hydrostatics, the pressure is also lower at shallower depths. Another part of the fluid will therefore move upwards. The least resistant pathway upwards will in this case be through the 9 5/8” liner annulus, which is a direct route to the cap rock. The 9 5/8” liner, 13 3/8” casing and casing shoe have higher strength than the cap rock formation. That means that the water will start to flow into the cap rock if the pressure of the injection water is higher than in the cap rock at this depth.

5.4 Simulations

The software used for the simulations that will be presented in this chapter is called Reveal. Reveal is a specialized reservoir simulator; a thermal reservoir simulator, which provides detailed wellbore modelling and a coupled geomechanical model. With this simulator, it is possible to add layers to the reservoir. These layers are overburden layers that represent the interaction between the reservoir and the cap rock. The data used in the simulations include both reservoir properties (e.g. porosity and permeability) and geomechanical properties (e.g. Young’s modulus, Poisson’s ratio and thermal expansion coefficient), both in the reservoir and the cap rock (OMV (Norge) AS 2018d; Petex n.d.). The optimal injection rate is highly dependent on several parameters. A small variation in a few parameters can have a significant effect on the rate. A base case has therefore been selected, based on data collected from the latest well (Wisting Central III). Due to a restricted number of Reveal software licenses, all the simulations in this chapter have been performed and provided by OMV (Norge) AS. The base case parameters are shown in the table below (Table 5.1).

Table 5.1: Reveal – base case parameters

Reservoir parameter	Value	Unit
Young's modulus reservoir	6	GPa
Thermal expansion coefficient	1.15 E-5	1/degC
Biot's coefficient	1.0	
Initial minimum horizontal stress	88	bar
Filter cake permeability (external)	0.01	mD
Operational parameters		
Degree of depletion	0	bar
Injection water temperature	7	degC
Duration of seawater injection	1	year
Degree of impurities in produced water: stepped up over 2 years (3, 6, 10)	10	ppm
Maximum injection pressure (constant limit over time)	80	bar
Period when high injection pressure is allowed (hydraulic fracturing)	0	weeks
Well design parameters		
Distance from cap rock (well located in the middle part of Stø Fm.)	10	m
Type of completion (fracture seeds along the well to allow several fractures; needs zonal isolation/completion to make this appear)	Screen/open hole	
Length of horizontal wellbore	600	m

Young's modulus is the elastic constant. It is the rock's ability to withstand changes in length when exposed to tension or compression. Young's modulus is defined as stress (the force on an object per area perpendicular to the force) divided by strain (the length change relative to the absolute length).

The stress (σ), with the unit Pa, is calculated by:

$$\sigma = \frac{F}{A}$$

Where F is the longitudinal force, and A is the area. The strain (ε), which is dimensionless, is calculated by:

$$\epsilon = \frac{\Delta L}{L_0}$$

Where ΔL is the change in length, and L_0 is the original length. And since Young's modulus (E) is defined as stress divided by strain, it becomes (Pa):

$$E = \frac{\sigma}{\epsilon} = \frac{FL_0}{A\Delta L}$$

(Agonafir 2018).

The thermal expansion coefficient is a material/rock property, which is a description of how the rock will change when temperature changes. All materials expand upon heating, and the thermal expansion coefficient is an indication of the extent to how much the individual material expands due to heating, or how it contracts due to cooling:

$$\alpha = \frac{\Delta V}{3V_0\Delta T}$$

α is the thermal expansion coefficient, ΔV is the change in volume, V_0 is the original volume, and ΔT is the change in temperature. By knowing the thermal expansion coefficient, the volume change can be calculated by re-arranging the formula:

$$\Delta V = 3\alpha\Delta T V_0$$

(Agonafir 2018).

The Biot's coefficient is the "*fluid volume change induced by bulk volume changes in the drained condition*" (Müller & Sahay 2016). According to Eirik Stueland (2019), the Biot's coefficient does not make a big difference in the simulations. Even though it is not exactly correct, it is assumed that the sand grains are incompressible. It is assumed that if the rock is expanded or compacted, the changes occur in the pore space, and not in the grains. The Biot's coefficient is therefore kept at a constant value, 1.0.

Horizontal stress is a force applied to the rock from a horizontal direction that could result in deformation of the rock. The horizontal stress will have similar changes as the pore pressure; in a depleted part of the reservoir, the horizontal stress will have decreased, while in a part of the reservoir where the pore pressure is increased, the horizontal stress will have increased as well. This force can be applied in several azimuthal directions (0-360°), and is separated by minimum and maximum horizontal stress (Agonafir 2018).

The external permeability is the permeability of the filter cake on the wellbore wall, and not the permeability in the formation, explained by Eirik Stueland (2019). The wellbore will be cleaned of any filter cake occurred during the drilling operation. The clean seawater will not create a filter cake, as it does not contain any particles. However, after a few years the seawater is replaced with cleaned, produced water, which contains particles that will start to form a filter cake.

Degree of depletion is how much the pressure decreases in the reservoir due to oil recovery.

The duration of seawater injection is 1 year, as shown in the table. This is a value that is not used as a variable in any of the simulations; it is constant for all cases.

Degree of impurities in produced water is how much particles and oil droplets, in parts per million (ppm), that are left in the injection water after the produced water has been cleaned. According to Eirik Stueland (2019), in the simulation it is assumed that the producer is producing at a rate of 3000 Sm^3/day, and that the injector is injecting with a rate of 1500 Sm^3/day. That will result in increasing water cut in the production, and thereby an increasing amount of solids in the re-injected water. The increasing amount of particles and oil droplets in time has been taken into account. The amount has been set to 3, 6 and 10 ppm in steps for the duration of 2 years.

As mentioned earlier, the maximum injection pressure has to be lower than the minimum horizontal stress, especially in the cap rock, but also in the reservoir to ensure no fractures. The minimum horizontal stress is the same (88 bar) in both the cap rock and the reservoir as per today. The maximum injection pressure is required to be below 88 bar, plus a safety factor, and is therefore set to 80 bar.

The distance from cap rock is set to 10 m TVD, i.e. in the middle of the Stø formation and in-between the two evaluated scenarios (fully cemented and non-cemented liner). In the simulation it is assumed that the liner is fully cemented. The consequence of the depth of the injection point is therefore clearer when the injector is placed in the middle of these outer "boundaries".

The length of the horizontal section of the wellbore affects the number of injection zones, and thereby the number of fractures that could occur. A longer well with several injection zones will enhance the fracture evolvement. It would result in several shorter fractures, rather than fewer longer fractures.

The first simulation, Figure 5.7, consists of the degree of plugging. There is no risk of fracturing the reservoir during the injection of clean seawater when injecting with a constant and safe pressure of 80 bar. But when the re-injection of produced water starts up, the risk becomes higher and higher the longer the produced water is injected, despite the constant pressure. The extent to which the reservoir matrix is plugged by solids contained in the injected water is one of the most important factors controlling fracturing around the injector. The more solids in the injection water the lower permeability in the filter cake. The simulation shows how the injection rate is affected by the plugging of the reservoir in time (each line in the figure represents 200 Sm^3/day and 1 year, respectively).

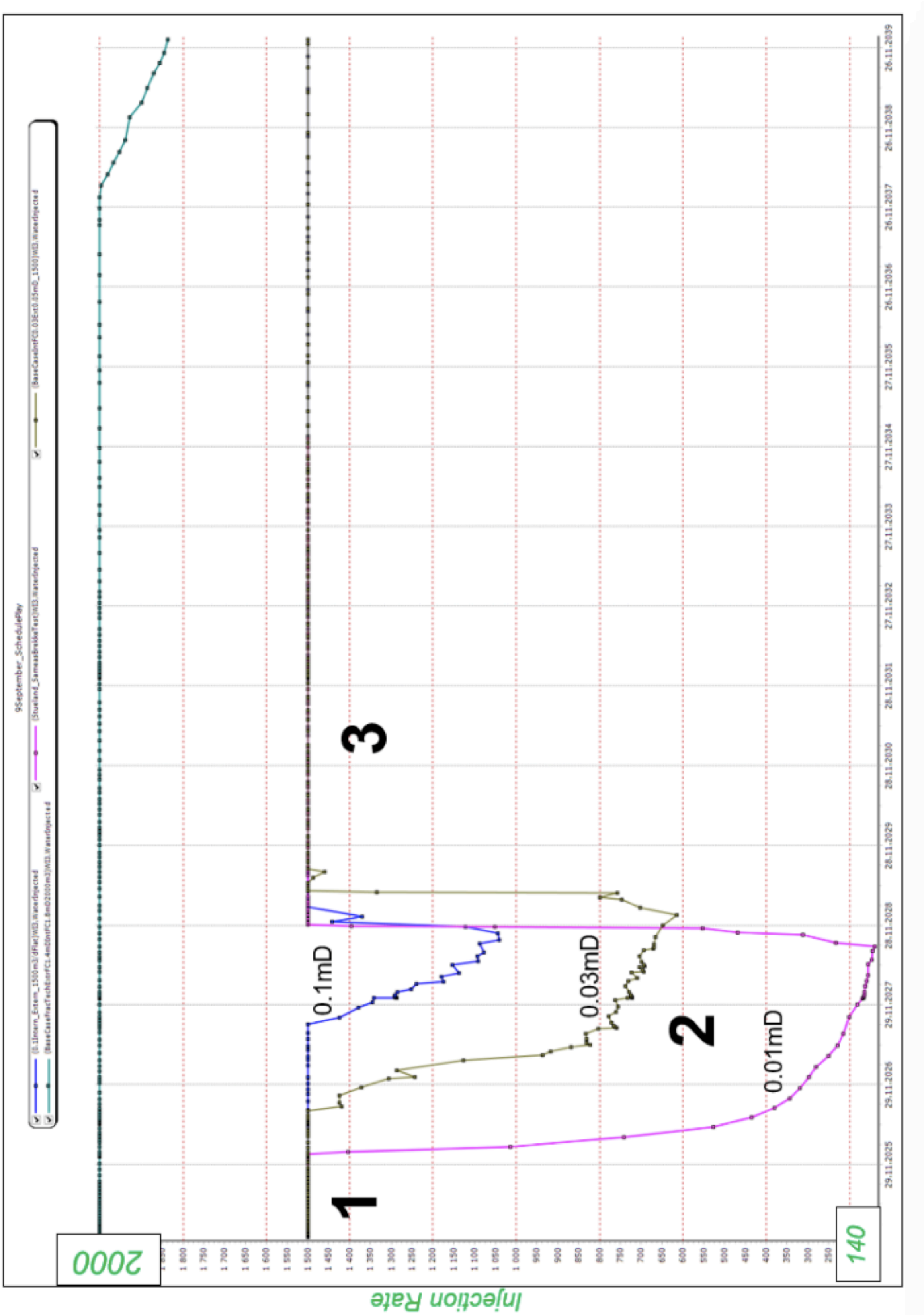

Figure 5.7: Wisting water injection – the effect of plugging on the injection rate (OMV (Norge) AS).

The figure visualizes the effect that three different values of filter cake permeability (in mD) have on the resulting injection rate, as well as a base case showing the maximum injection rate (2000 Sm^3/day) with only seawater as injection fluid. The numbers 1, 2 and 3 represent three distinct periods of the injection. Number 1 represents the seawater injection period, before water breakthrough in the producer. There is only matrix injection, without any plugging of the reservoir. The next period, number 2, represents injection of produced water before fracturing appears. The solids in the injection water start to plug the reservoir, leading to a reduction in injection rate. The final period, number 3, represents injection of produced water after the fracturing has been initiated. The fractures will enhance the injection rate, and the bottomhole pressure should be kept below the minimum horizontal stress of the cap rock to prevent the fractures to propagate into the cap rock. More fractures will reduce the length of each fracture, and increase the time before the fractures extend to the cap rock. A multi-zone completion with adequate pressure and flow control, i.e. Downhole Instrumentation And Control System (DIACS), will increase the chance of generating multiple fractures instead of only one.

The simulation has indicated that it is not possible to use PWRI without fracturing the formation due to the filter cake that will occur on the wellbore wall. Therefore, the recommendation is to place the injection points as low as possible in the reservoir to increase the distance to the cap rock.

It has been indicated that there is a relationship between the water injection rate and the fracture propagation, which is why there is a constraint on the injection rate. The two next simulations (Figure 5.8 and Figure 5.9) provide information about how the fractures are affected by different injection rates. According to the base case parameters, the distance from the cap rock is 10 m TVD. However, the well trajectory cannot follow the cap rock by exactly 10 m throughout the whole horizontal section, and the simulation of the minimum distance between the fracture and the cap rock therefore deviates a bit from this distance.

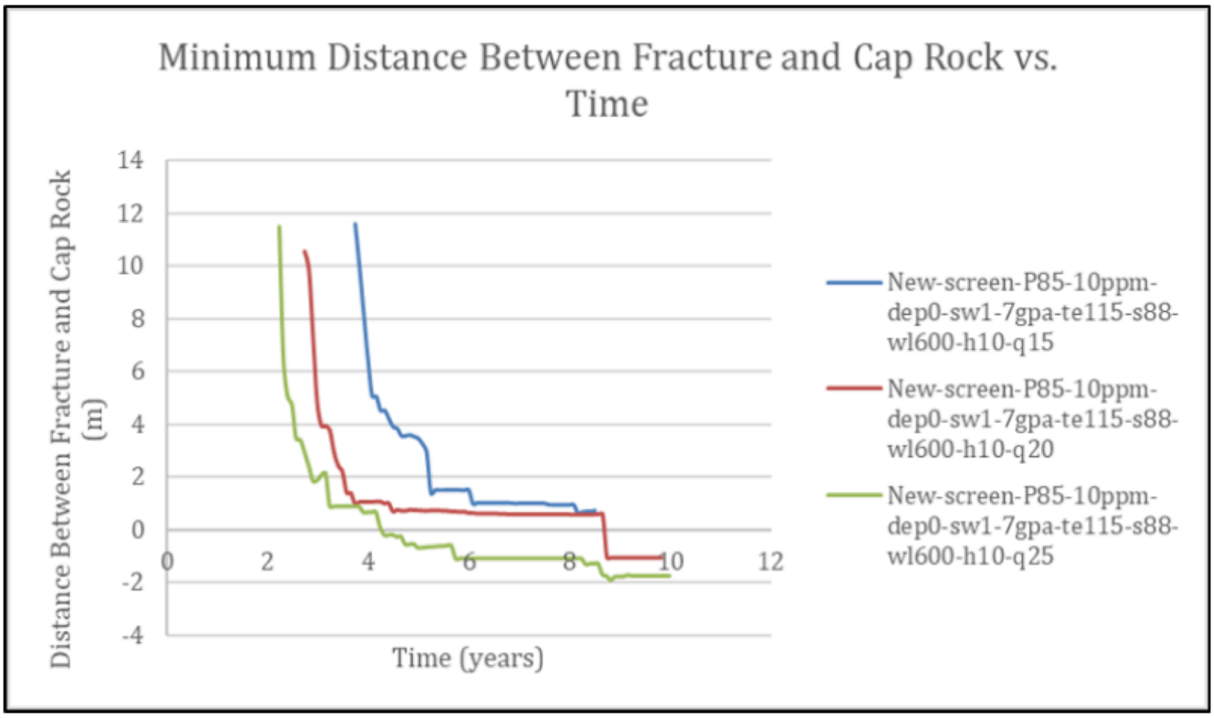

Figure 5.8: Minimum distance between fracture and cap rock vs. time (OMV (Norge) AS).

Figure 5.8 shows the minimum distance between the fracture and the cap rock for different injection rates, and how this distance changes with time. The green line is the distance when injecting with 2500 m^3/d, red is with 2000 m^3/d, and blue is with 1500 m^3/d. According to the figure, the fractures will not enter the cap rock with an injection rate of 1500 m^3/d. It also supports the assumption that the fractures will reach the cap rock earlier with higher injection rate. After approximately 4 years, the fractures will enter the cap rock if the injection rate is as high as 2500 m^3/d.

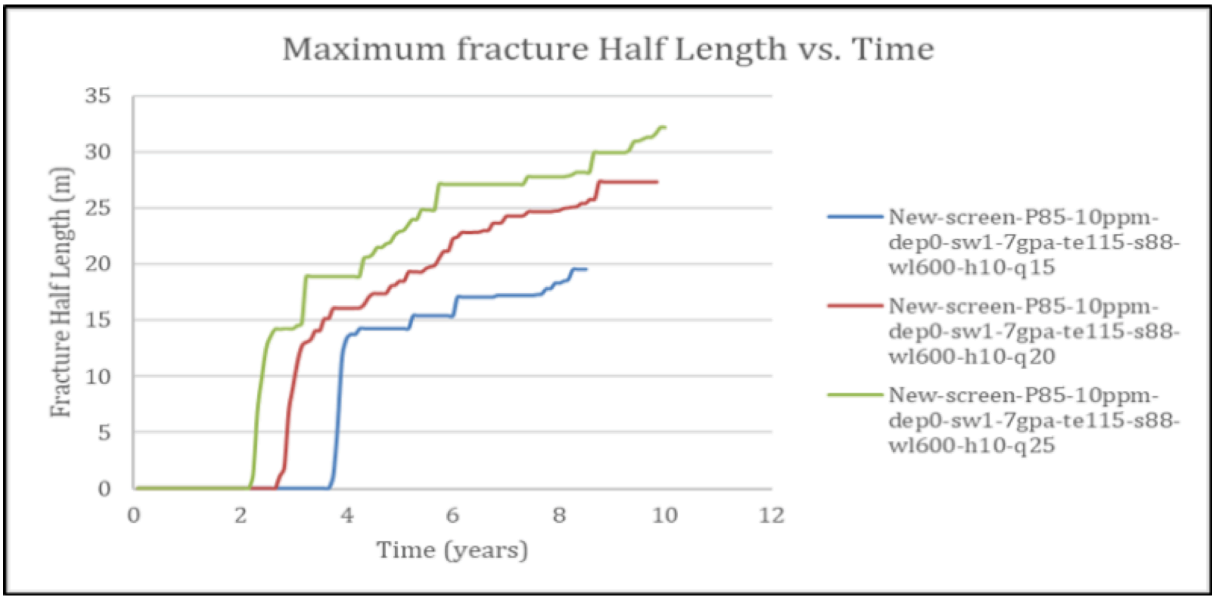

Figure 5.9: Maximum fracture half-length vs. time (OMV (Norge) AS).

Figure 5.9 shows the maximum half-length of a fracture for the same injection rates as in Figure 5.8, and how they evolve over time. A fracture half-length is the length of a fracture on one side of the well. One fracture length is assumed to consist of two equal half-lengths in each side of the well (Cheong 2016). Both simulations show that a fracture will evolve faster and further with increasing injection rate, and they are both very dependent on the characteristics of the filter cake. The fractures will be shorter, and will not propagate as aggressively, by assuming a higher external permeability.

The next simulation, Figure 5.10, is a sensitivity of filter cake permeability on the injection rate. It is based on plugging experiments, where OMV (Norge) AS is testing the permeability reduction for different grain sizes, concentration, oil droplets in the water, etc. The permeability parameters have a large uncertainty over field life, and therefore several values of external permeability have been tested (0.01 mD, 0.1 mD, 0.5 mD, 1.0 mD and 1.4 mD, respectively) with a constant bottomhole pressure of 80 bar. These parameters are constant in the Reveal reservoir simulator, but an extra detail has been added; the permeability of the filter cakes are not forming until the produced water re-injection is introduced in the simulation (after 1 year of injection).

The first stage for all the different values of external permeability in Figure 5.10 is matrix injection. After a period of time, depending on the value of the filter cake permeability, the injection rate will start to drop due to plugging. The next stage will be hydraulic fractured injection, and the injection rate will return to the initial injection rate. As the simulation will show, the time spent on injection under matrix conditions will increase with higher filter cake permeability, and the potential drop in injection rate will have less impact.

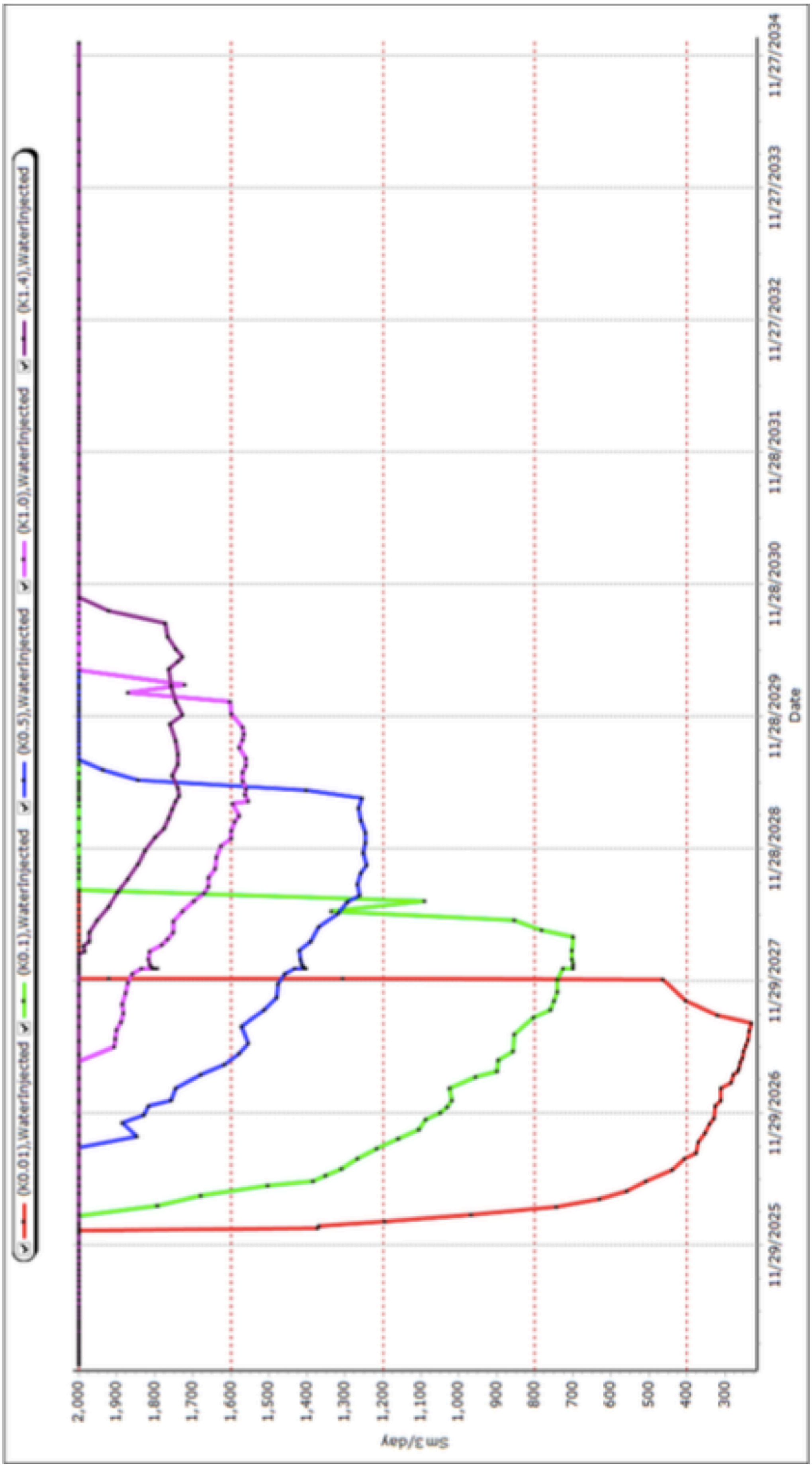

Figure 5.10: Sensitivity of filter cake permeability on injection rate (OMV (Norge) AS).

In addition to affecting the injection rate and time of matrix injection, the solid content, or produced water quality, is assumed to also affect the evolution and size of fractures. A sensitivity was therefore simulated for solid contents in the produced water, and instead of filter cake permeability, the ppm was set as the variable. Three different values are represented in the simulation (Figure 5.11); the red curve has 20 ppm, the blue has 10 ppm, and the green has 6 ppm.

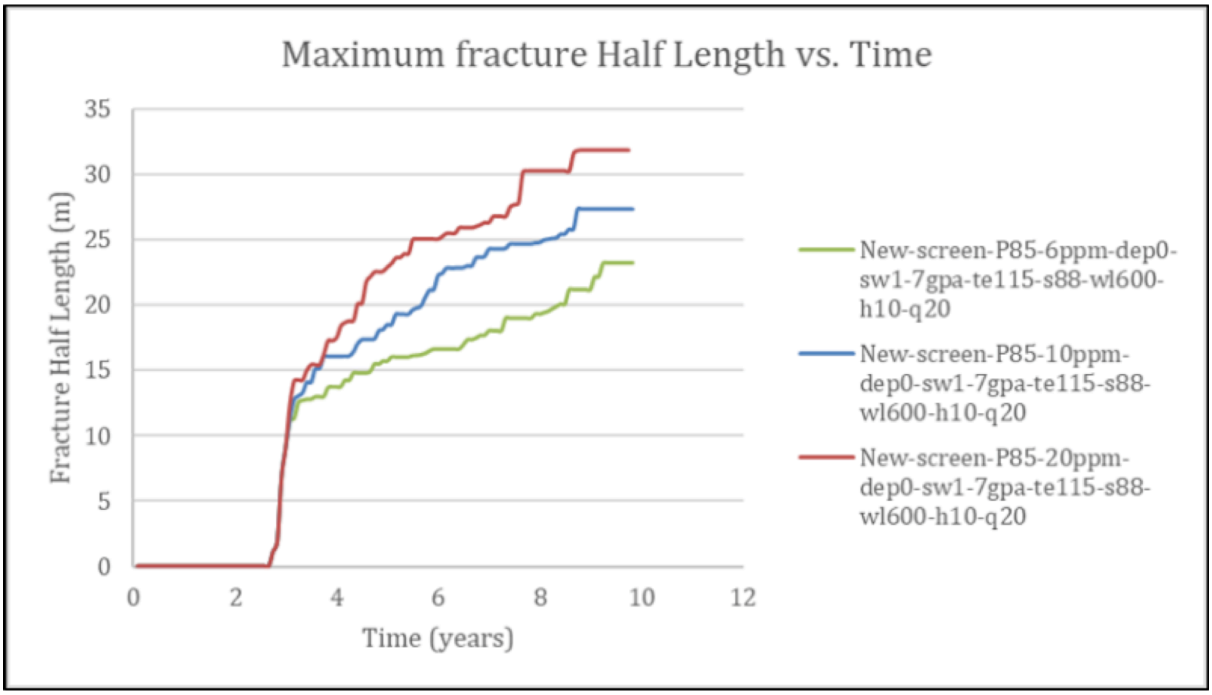

Figure 5.11: Fracture half-length vs. time for different ppm values (OMV (Norge) AS).

Also these results show that the time of matrix injection is influenced by the water quality (ppm). The plugging happens faster when the injection water contains more solids. However, this simulation's main result is how the ppm affects the fractures. As the simulation shows, the fractures becomes both longer and wider as the ppm is increased when in fracture mode.

The thermal expansion coefficient is as mentioned a property of the rock, which determines how the rock changes when the temperature changes. The reservoir is not completely uniform, and the thermal expansion coefficient may therefore vary along the horizontal well. Young's modulus is also a rock property, and may also change along the horizontal section. The base case value used for thermal expansion coefficient is 1.15 E-5 1/°C (blue curve). In addition to the base case, two more values have been added for this simulation (Figure 5.12): 2.00 E-5 1/°C (red curve) and 3.00 E-5 1/°C (green curve).

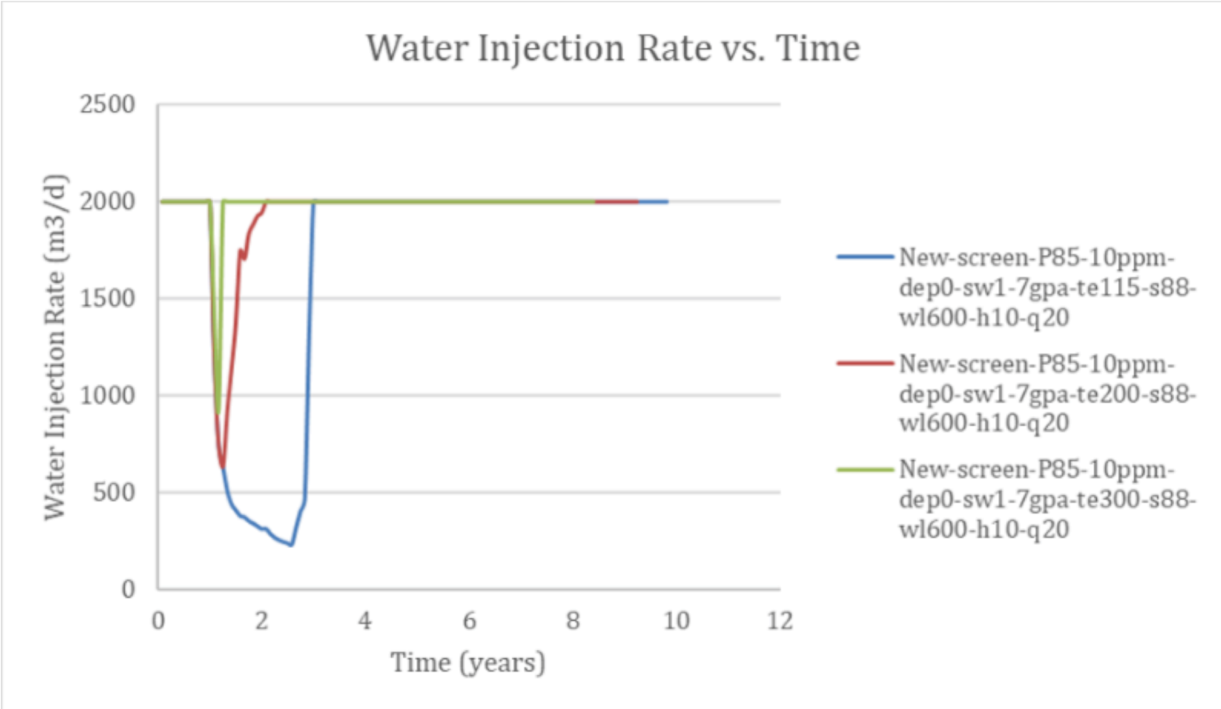

Figure 5.12: Effect from thermal expansion coefficient on fracture initiation (OMV (Norge) AS).

The simulation above (Figure 5.12) shows that the injection rate drops almost simultaneously, regardless of the thermal expansion coefficient value. However, the lower thermal expansion value, the further and slower the injection rate drops. According to this simulation, it is possible to keep the injection rate at a high level despite the bottomhole pressure restriction that has been applied to ensure safe injection, as long as fractures are acceptable at the specified time for the relevant coefficient.

As mentioned in the matrix injection chapter, the idea is to inject cold water into the reservoir without fracturing it. It is assumed that if this is done successfully, the cooling of the reservoir will increase the stress contrast. However, it is also assumed that the cap rock also will be cooled eventually during the field life, as it will be exposed to the cold water in the reservoir beneath. To find out to what degree the cap rock is affected by the cooling of the reservoir, a simulation of the temperature effect on the stresses has been run (Figure 5.13 and Figure 5.14). Both simulations are dependent on the thermal expansion coefficients of the reservoir and the cap rock. Figure 5.13 shows time (1 year for each line) on the x-axis and temperature (2 degrees Celsius for each line, except for the first line, which is 1 degree Celsius) on the y-axis, and the different curves in the simulation represent the stress on different depths in the reservoir and cap rock. The reservoir being the lower curves/cells and the cap rock being the upper curves/cells, as indicated in the figure.

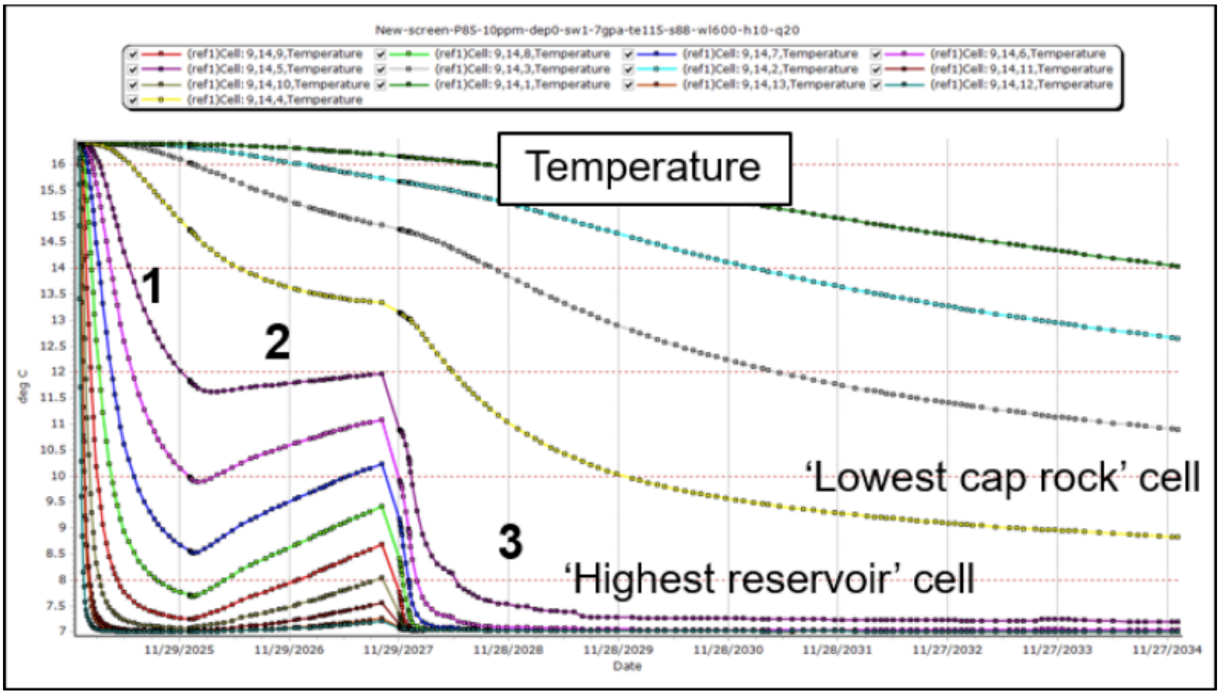

Figure 5.13: Temperature effect on the stresses (temperature vs. time) (OMV (Norge) AS).

The cold water lowers the temperature and the stresses in the reservoir, but potentially also in the cap rock over time. As can be seen in Figure 5.13, the result of the simulation has been divided into three sections. In the first section, the temperature has a rapid drop caused by extensive matrix injection. After a period of time with temperature drop, the temperature equalizes in the second section as plugging lower the injection rate. Finally the reservoir fractures (after approximately 2.85 years), increasing the injection rate, and the temperature drops again. As can be seen in the figure, the cap rock is not affected as much as the reservoir, as the fractures will form 10 meters (base case) below the cap rock where the cooling effect is greatest.

The curves, or cells, in Figure 5.14 represent the same as in Figure 5.13; stress on different depths in the reservoir and cap rock. It can be a bit more difficult to separate the cells in the beginning of the simulation in Figure 5.14 than it is in Figure 5.13. It is easier to separate the cap rock from the reservoir towards the end. In Figure 5.14, the x-axis represents time (1 year for each line) and the y-axis represents pressure (4 bar for each line).

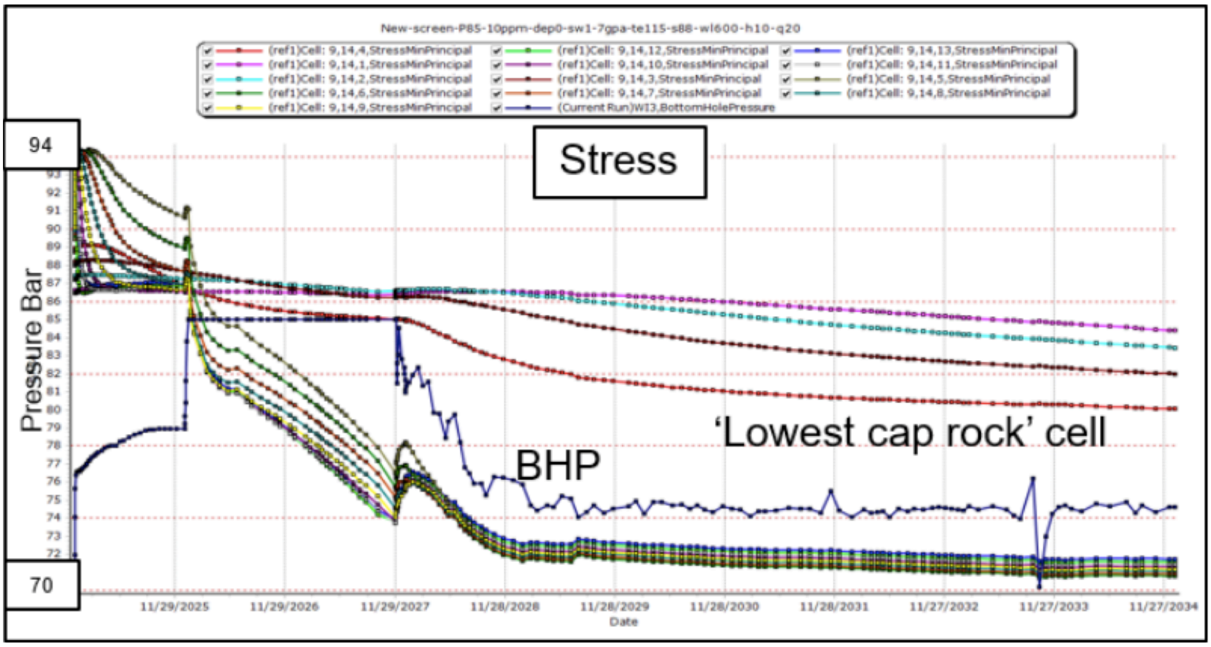

Figure 5.14: Temperature effect on the stresses (pressure vs. time) (OMV (Norge) AS).

In the beginning of the simulation in Figure 5.14, the pressure in the reservoir is naturally higher than the pressure in the cap rock, as the reservoir is deeper than the cap rock and the hydrostatic column is larger. After some time with injection and cooling, the stress in the reservoir drops below the cap rock stress. By comparing Figure 5.13 and 5.14 similar trends can be seen. First the drop due to extensive matrix injection, then at approximately the same time in both figures, the temperature/pressure equalizes due to plugging, and finally a second drop in both temperature and pressure due to fractures increasing the injection rate. The bottomhole pressure has also been added to the simulation in Figure 5.14. The BHP increases to 85 bar when the formation is plugged, and maintains this pressure until fractures are initiated. The BHP in the injector well is dropping when entering fracturing mode.

6. Results and discussion

Both the literature searches and the simulations have shown that produced water re-injection always results in fracturing; the question is will it affect the cap rock when this happens? And how will the cement in the 9 5/8" liner annulus affect the results? Fracturing is the most crucial part of the water injection on Wisting, no matter what part of the operation being studied, even when studying the cementation of the liner. The quality of the cement job decides the depth of the injection point, and thereby the shallowest depth a fracture could appear.

6.1 Cement

The previous wells on Wisting have been cemented with 1.90 sg cement class G, including different additives, depending on the challenges for each section in each well. Even though there exist several special types of cement slurries designed for different wellbore challenges, it is possible to mix a composition that will meet the cement requirements.

After evaluating the chosen selection of cement types from Schlumberger, the lightweight cement slurry stands out as the optimal choice. This cement slurry "(…) *addresses specific long-term challenges with well integrity*", according to Nadya Lyapunova (2019), and the main challenge addressed by the lightweight cement is exceeding the fracture pressure (minimum horizontal stress). Due to the uncertainty of reaction with oil droplets in the injection water, the self-healing cement slurry is not needed for this feature. The self-healing cement also has the capability to expand as it sets in the annulus, but this property exist as an additive, making it possible to mix it in another cement slurry for the same effect. The main benefit of the flexible cement slurry is the flexibility with regards to pressure and temperature variations due to the low Young's modulus. Still, as the pressure and temperature already is very low in the formations, the need for this effect is very small. Even though the previous wells have been cemented with class G cement, it could be beneficial to select the lightweight slurry to reduce the risk of both fracturing the formation and losses. The lightweight cement has a high compressive strength despite the low density, and is therefore very compatible for hydraulic fracturing treatments, i.e. the cement column will not be damaged even though the injection pressure might come close to, or exceed, the fracture pressure of the reservoir.

When it comes to the selection of cement from Baker Hughes GE, it is the foam cement slurry that stands out. The self-healing cement appears to be a high-quality cement slurry. However, this cement type benefits a production well more than it does an injection well due to the uncertainty of hydrocarbons present in the injection water. The lightweight cement was as mentioned as a recommendation by Antonio Bottiglieri (2019) to mitigate losses, but as foam cement is even lighter and as it expands as it sets, it appears to be more adequate for the desired purposes. As other results will confirm later, the level of successful cement will affect the injection performance. However, if further tests and data show that a class G cement with additives is enough, it is not necessary to increase the costs because of more advanced cement slurry.

6.2 Cement evaluation

The cement sheath around the liner in the reservoir can be verified by two methods, either bond logging or 100% displacement efficiency (NORSOK Standard D-010 2013). As mentioned earlier, it is beneficial for the P&A operation to log the cement sheath. A few types of cement evaluation services have been selected for evaluation from both Schlumberger and Baker Hughes GE.

From Schlumberger it is the Bond Logging Tool, the Power Flex and Power Echo, and the Isolation Scanner. The difference between these is that the Bond Logging Tool is a single tool used for evaluation of cement quality, while the others combine several tools similar to the Bond Logging Tool. The Bond Logging Tool evaluates cement quality, zonal isolation, location of top of cement, and bond between casing and cement. If this is all the data needed for cement evaluation, then the Bond Logging Tool is a good option. The PowerEcho offers information about the casing pipe as well as information about the cement bond to casing. The PowerFlex includes all the same information that the PowerEcho offers, in addition to some extra features, such as VDL for example. The Isolation Scanner is a bit more advanced, and is able to identify small channels in the cement. By running the Isolation Scanner as a combination with e.g. VDL, it is possible to determine the cement bond to the formation. Even though the Isolation Scanner is more advanced, and probably more expensive, it might be necessary to invest in this cement evaluation service due to the importance of the liner cement.

When it comes to Baker Hughes GE's cement evaluation service selection, the evaluated services are the Segmented Bond Tool (SBT), the ChannelView Well Integrity Detection Service and the Integrity eXplorer (INTeX) Cement Evaluation Service. There is a difference between these three services, similar to the one for Schlumberger's services. The SBT is a single tool providing logs and measurements down hole. It also provides a VDL enabling it to determine the cement bond to both the casing and the formation. Both the ChannelView and the INTeX combine several tools to provide more information. The INTeX service has its own tool, but has to be combined with a VDL to provide data on cement bond to the formation. The ChannelView service combines the Segmented Bond Tool with other tools, e.g. the Reservoir Performance Monitor. By combining these two tools, the ChannelView is not only able to identify channels in the cement sheath, but also the presence of water in these channels. The most important objective for the Wisting water injector is to identify any channels in the cement. For this task only, the SBT is suitable. As the well is a water injector, it would be beneficial to be able to identify water in the channels as well. However, in the evaluation of these services, the only considered use of them is right after the cement has set, i.e. prior to injection start-up.

6.3 Plug and abandonment

It is important to log the cement with respect to the plug and abandonment at the late life of the well. Figure 3.8 and 3.9 show that there is not very much change in temporary P&A with or without cement outside the 9 5/8” liner. The only change is that the primary and secondary well barriers transfer upwards in the well in Figure 3.9. However, the well and formation integrity will be easier maintained with a fully cemented liner. Figure 3.10 and 3.11 show the same difference between the two scenarios for permanent P&A, the barriers are transferred further up in the case of no cement outside the liner. Another difference worth noting is the cement volume. With a fully cemented liner, the cement plugs can be set deeper in the well, and most of the primary cement plug will be inside the 9 5/8” liner. The 9 5/8” liner has a smaller diameter than the 13 3/8” casing, hence the volume of cement required to create a cement plug of 100 m MD will be less than for a non-cemented liner, where the whole primary cement plug will be in the 13 3/8” casing.

6.4 Simulations

As most of the simulations indicate, the plugging of the reservoir and filter cake does not start simultaneously as the PWRI starts. Seawater is injected for 1 year (base case), but it will naturally take some time before the particles in the produced re-injected water start to plug the reservoir and filter cake enough to affect other parameters, e.g. the injection rate.

The first simulation (Figure 5.7) shows how plugging of the reservoir affects the injection rate, and that a lower reservoir permeability results in earlier injection rate reduction. There are three actions that can be made to mitigate the period of reduced injection rate during matrix injection:

- Drill the wellbore as long as possible. Other simulations in Reveal have also confirmed this (OMV (Norge) AS).
- Use cold injection water. Then, once the plugging begins, the reservoir is already cooled and likely to start fracturing, and the fractures will be contained in the reservoir, as the depletion and cooling will generate a contrast in fracturing pressure between cap rock and reservoir.
- Apply a high injection pressure (above the cap rock fracturing pressure) before fractures start propagating. However, it needs to be proven by simulations that these fractures will not reach the cap rock.

By having a non-cemented liner in the reservoir, the first point above will be fulfilled, although in a slightly different way than intended. Even though a non-cemented liner will result in a longer section with formation contact, and a longer period of matrix injection without plugging, the injection rate has to be reduced due to the risk of exceeding the minimum horizontal stress at the injection point in the cap rock.

Figure 5.8 shows the simulation of the minimum distance between fracture and cap rock with time, and according to the simulation, the fracture will never enter the cap rock with an injection rate of 1500 m^3/d. However, the simulation is based on the base case, i.e. the distance between the horizontal section of the well and the cap rock is approximately 10 m TVD. The simulation is correct for the scenario with a fully cemented liner. The scenario with the non-cemented liner on the other hand will be a bit different. However, due to hydrostatics, the pressure will be a bit lower at the injection point just below the 13 3/8" casing shoe, and the cap rock will therefore be able to withstand the pressure at an injection rate of 1500 m^3/d. A later simulation supports this. The two other injection rates will however fracture the cap rock as shown in Figure 5.8. The difference in the two scenarios is that with a non-cemented liner, the fractures will enter the cap rock at a much earlier time due to the distance between the injection point and the cap rock.

The fracture half-length (Figure 5.9) is not directly dependent on the cementation job of the liner. It is however dependent on the injection rate, as shown in the simulation. And the injection rate is dependent on the quality of the cement sheath. As the non-cemented liner requires a lower injection rate, the maximum fracture half-length will be shorter in this scenario according to the simulation.

The effect of filter cake permeability on the injection rate due to plugging, as shown in Figure 5.10, is very significant. Lower filter cake permeability will lead to lower injection rate and shorter period of matrix injection, despite the constant BHP. It is, in other words, the restriction caused by the permeability that reduces the injection rate. The formation will eventually fracture, due to e.g. thermal effects and reservoir depletion. These two (thermal effect and depletion) reduce the stresses over time, and even though the bottomhole pressure is constant, the reservoir will fracture as the fracture pressure thereby also is reduced. To be able to prolong the matrix injection as much as possible, the produced water could be cleaned and filtered, providing as clean injection water as possible. This simulation is not directly affected by the quality of the cement job, but as the injection rate already has to be reduced in a non-cemented liner scenario, low filter cake permeability will further reduce the rate, and that could result in a reduced life of the well.

The simulation in Figure 5.11 shows that water quality has a strong influence on the fracture half-length. The ppm does not change due to the cement quality even though the injection point does. But as the injection interval changes along with the injection point, the injection water has a longer distance to plug with a non-cemented liner, compared to the case with a fully cemented liner. In addition to this, as the flow control valves are installed in the horizontal section, the particles will most likely plug the horizontal section before the inclined section up to the casing shoe. However, the effect of ppm will be the same for both scenarios. An increase of ppm will increase the length and width of the fractures, independent of the cement outside the liner.

The simulation of the thermal expansion coefficient effect on fracture initiation (Figure 5.12) shows that a higher thermal expansion coefficient will initialize fractures earlier. The fractures are initiated almost instantly after plugging appears. It was also mentioned that the coefficient might vary along the horizontal section. This could be an advantage. Encountering zones with higher thermal stress means that fractured injection could happen earlier, and that the potential period with lower injection rate caused by plugging could be reduced. Lower thermal expansion coefficient would cause a great loss in cumulative injected volume, and thereby also injection and production productivity and profit. Without cement around the liner, the injection interval stretches in the vertical direction as well, which means that it crosses a few layers in the reservoir, as the reservoir is not fully homogeneous. In that case, encountering a zone with higher thermal stress could be critical for the cap rock integrity. Reducing the water injection rate could mitigate this. By reducing the injection rate, the matrix injection time would be increased, delaying fracture initiation close to the cap rock.

The two figures (5.13 and 5.14) involving the simulation of the temperature effect on the stresses in the cap rock and the reservoir, show that the lower part of the cap rock is being cooled, but not as much as the reservoir. The cap rock is less permeable than the reservoir, and the cool injection water therefore never enters the cap rock, it only flows along the lowest cap rock cell. The stresses in the cap rock also decreases, but they do not decrease as much as the stresses in the reservoir either, and the stress contrast therefore tends to increase. The results of the simulations are promising for a fully cemented liner. However, without the cement in the liner annulus, the cold injection water will flow along the cap rock, cooling it already from the start. The gap between the highest reservoir cell and the lowest cap rock cell, as shown in the simulations, will decrease significantly. The reduction in temperature contrast between these two cells would affect the desired effect on the stress contrast, also shown in Figure 5.4, and increase the risk of fractures entering the cap rock.

6.5 Cooling effect

The cooling effect makes the formation more brittle, i.e. the formation is fractured easier. There are both advantages and disadvantages with a more brittle reservoir. An advantage is that the injection pressure and rate can be maintained at a high level with fractures that are not plugged, especially if matrix injection is successfully executed for a long enough period of time. The injection water will then cool the reservoir enough so that the stress contrast is increased enough for the fractures to be contained within the reservoir according to the simulations. A disadvantage is that there could already be some unknown fractures in the reservoir that will propagate at the injection pressure. If those fractures start to propagate before the reservoir has been cooled, and the stress contrast increased, there is a risk of the fractures propagating into the cap rock. An alternative could be to pump warm water into the formation, which will makes the rock less brittle. However, that could result in a formation that never fractures, pores that gets plugged by the produced water, an injection rate that keeps decreasing with time, and an injector which life lasts less than desired.

6.6 Pre-fracturing

A pre-fracturing job has been evaluated as an option for the injection project. A pre-fracturing job is when the injection operation is kicked off with high injection rate and pressure, forcing the reservoir to fracture along the injection interval. After the fractures have been created, the injection rate and pressure are reduced and maintained below the fracture propagation pressure, at a maximum. The fractures will improve the injection productivity by enabling the injection water to flow through a more accessible pathway further into the formation. However, there are some uncertainties related to the fracture initiation, also illustrated in Figure 6.1 on the next page. Will the initiation of the fractures cause particles along the fracture wall to loosen from the wall, be swept into the fracture with the injection water, and start plugging the fracture just as it has been initiated? And will the friction from the injection water cause the same challenge? The Wisting-team in OMV (Norge) AS is planning to perform some tests related to these challenges. The results from the tests could make a great difference in the simulations regarding fractures (especially the simulations presented in Figure 5.8 and 5.9), as well as in the decision-making related to the fracturing of the reservoir. It could prove to be even more important to avoid fractures, or that the fractures will not enhance the injectivity as anticipated.

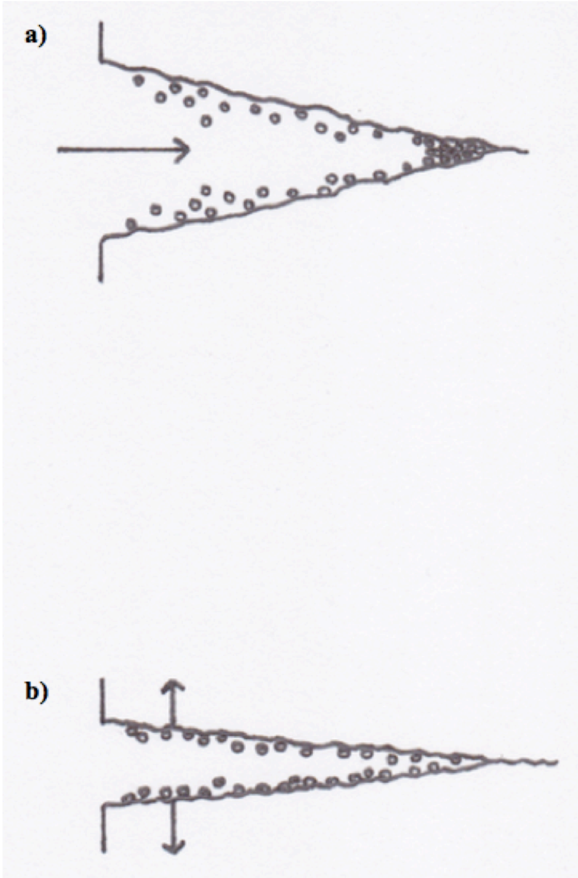

Figure 6.1: Plugging of fractures (based on Kamsvåg 2019b).

6.7 Fully cemented liner vs. non-cemented liner

As mentioned earlier, the minimum horizontal stress in the cap rock and in the reservoir is 88 bar. And the first simulation, Figure 5.7, supported that the injection point should be as deep as possible in the reservoir to increase the distance to the cap rock. This depth represents the depth of the injection point for a fully cemented liner, while the injection point for a non-cemented liner is in the cap rock. As shown in figures 5.5 and 5.6, there is approximately 20 m TVD and 0 m TVD between the cap rock and the injection points, respectively. It has previously been stated that the maximum injection pressure is 80 bar, assuming the liner is fully cemented. The reason for the maximum injection pressure being as much as 8 bar less than the minimum horizontal stress, is the need of a safety factor in case the data should be overestimated. The maximum injection pressure in a case with a non-cemented liner should therefore be 80 bar minus the hydrostatic pressure down to the deepest injection point. Assuming that 20 m TVD corresponds to approximately 2 bar plus a safety factor, the maximum injection pressure for a non-cemented liner would be approximately 10 bar less than for a fully cemented liner. The maximum injection pressure for a non-cemented liner would therefore be around 70 bar. Also, according to Trygve Kamsvåg (2019b), Equinor has assumed an injection index of 50 m^3/bar/day. With this injection index, the 20 m TVD and 2 bar difference between the two scenarios becomes:

$$Injection\,rate\;difference = 50\ m^3/bar/day * 2\;bar = 100\ m^3/day$$

And as 1500 m^3/day was indicated to be the safest injection rate in Figure 5.8 and 5.9, it means that the maximum injection rate for a fully cemented liner could be 1600 m^3/day. As a result of this, the long-term effect on the injection rate has been simulated in Figure 6.2. The green line represents the fully cemented liner with a maximum injection rate of 1600 m^3/day, and a maximum, constant injection pressure of 80 bar. The red line represents the non-cemented liner with a maximum injection rate of 1500 m^3/day, and a maximum, constant injection pressure of 70 bar.

As the simulation shows (in Figure 6.2), with time (1 year for each line) on the x-axis and injection rate (80 Sm^3/day on each line) on the y-axis, the two different pressure restrictions have a significant effect on the injection rate. After a few years, in the case of a fully cemented liner and a pressure restriction of 80 bar, the injection rate will start to drop to approximately 1000 m^3/day during matrix injection due to plugging of the formation. Then, there is a sudden increase in the injection rate, representing the initiation of fractures, and the injection rate is back at 1600 m^3/day, prolonging the life of the injector. The result of a non-cemented liner, with a pressure restriction of 70 bar, is very different. The formation never fractures. The injection rate just keeps decreasing, until it ends up on approximately 380 bar. However, even though the injector keeps injecting into the reservoir, the productive and economical period of the injector's life is over long before the injector is dead. The injector will be plugged and abandoned as soon as it stops being profitable.

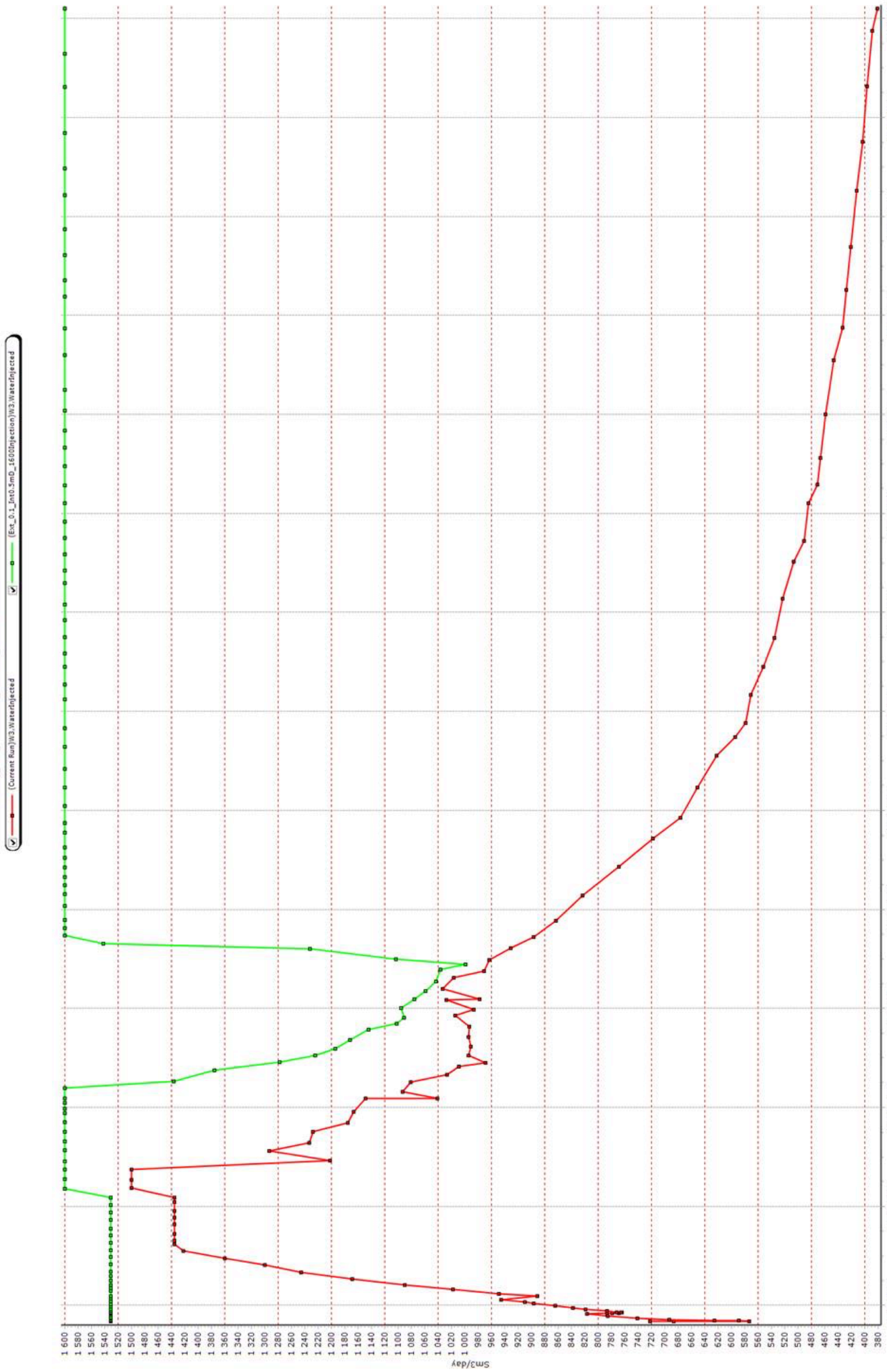

Figure 6.2: Effect of pressure limitation on injection rate.

7. Conclusion

The last simulation (Figure 6.2) is based on the assumptions and calculations above the simulation, in addition to the same base case as the pervious simulations. It shows how the two different pressure restrictions, depending on the cement around the liner, affect the injection rate and fracture initiation. As has been shown earlier in chapter 6, the injection rate and performance are not only dependent on the pressure restriction. Several simulations have been run and included in this thesis. Some of them do not have a clear and direct link to the objective. However, every single one of them does have an affect on the final result of the importance of the liner cement and the effect on the injectivity.

It is crucial for the injection performance that the liner is fully cemented. The injection rate can then be maintained on the desired level, and the risk of fracturing the cap rock is mitigated. The safest cement option for the 9 5/8” liner would either be foam cement from Baker Hughes GE or the lightweight cement from Schlumberger, reducing the hydrostatic pressure and potential losses. Baker Hughes GE’s Segmented Bond Tool could be the preferred option to verify the cement as a successful barrier, unless more information than the cement bond to the liner and formation is needed. Then Schlumberger’s Isolation Scanner could be the favourable service. On that note, if the foam cement would be used, then both the INTeX (Baker Hughes GE) and the PowerFlex (Schlumberger) would be adequately equipped to log and verify the cement sheath.

In conclusion, the 9 5/8” liner cement as a barrier is crucial for this Wisting water injection operation. The consequences of a non-cemented liner make a great difference in a number of ways. A fully cemented liner would mean great cost benefits, it would provide extra protection for both well and formation integrity, and improve the injectivity, with respect to both the lifetime of the well and the much mentioned injection rate.

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Abbreviations

Bbl – Barrels

BHGE – Baker Hughes GE

BHP – Bottomhole pressure

BOP – Blowout preventer

CAN – Conductor Anchor Node

CML – Cement mortar lining

DHSV – Downhole safety valve

DIACS – Downhole Instrumentation And Control System

ECD – Equivalent circulating density

FBP – Fracture breakdown pressure

FCP – Fracture closing/closure pressure

FCV – Flow control valve

FIP – Fracture initiation pressure

FIT – Formation integrity test

Fm. – Formation

FPP – Formation propagation pressure

HXMT – Horizontal Christmas tree

ID – Inner diameter

ISIP – Initial/instantaneous shut-in pressure

INTeX – Integrity eXplorer™

LOP – Leak-off pressure

LOT – Leak-off test

LPLT – Low pressure, low temperature

MD – Measured depth

NCS – Norwegian continental shelf

OD – Outer diameter

OOZI – Out of zone injection

P&A – Plug and abandonment

PDL – Pre-drilled liner

Ppm – Parts per million

PWRI – Produced water re-injection

ROV – Remotely operated vehicle

RPM – Reservoir Performance Monitor^{TM}

SBT – Segmented Bond Tool^{TM}

sg – Specific gravity

Sg. – Subgroup

SLG – Solid-liquid-gas

TOC – Top of cement

TRSV – Tubing retrievable safety valve

TVDss – True vertical depth sub-sea

VDL – Variable-density log

VXMT – Vertical Christmas tree

WBE – Well barrier element

WBS – Well barrier schematic

WH – Wellhead

WI – Water injection/injector

XLOT – Extended leak-off test

XMT – Christmas tree

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