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Influence of Casing Shoe Depth on Sustained Casing Pressure

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Background:
A recent survey performed by the Petroleum Safety Authorities Norway (PSA), showed that about 20 % of the wells on the Norwegian Continental Shelf (NCS) have reported well integrity problems. Pressure build-up in annulus, i.e. sustained casing pressure (SCP), is frequently occurring in many wells and is one of the main indicators of a significant well integrity problem.

A major operator on the NCS has claimed that a significant portion of their well integrity problems are caused by poor selection of casing shoe depths. However, the reasons for this are complex and not fully understood.

Task:
1) Describe the phenomena SCP and its most common causes.
2) Discuss how wrong casing shoe depth may cause SCP; with an emphasis on formation strength and geological aspects.
3) Provide suggestions on how to improve well design in order to avoid SCP.

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……………………………….
Sigbjørn Sangesland

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Summary

In 2006 the Petroleum Safety Authority Norway (PSA) performed a well integrity survey. The survey indicated that about 20 % of wells on the Norwegian Continental shelf (NCS) may suffer from well integrity issues. Most of the problems were related to deficiency in annulus safety valve, tubing, cement and casing. Pressure build-up in annulus, i.e. sustained casing pressure, is one of the main indicators of a significant well integrity problem. Increased understanding on the field may help engineers to design wells with better integrity in the future.

This thesis describes SCP and its most common causes with emphasis on the relation between casing shoe setting depth and the occurrence of SCP. Primary and secondary barrier is described together with the common practice of choosing casing shoe depth. Formation strength and its impact on setting depth is explained together with a brief introduction of the different formation integrity tests.

Generic cases have been studied to determine the relation between unfavorable casing shoe setting depth and the occurrence of SCP. For each case there is a suggestion as how the well may be redesigned so that the risk of SCP is reduced. Information on the theme has been acquired through studying and comparing different papers, booklets, previous reports and reviews concerning the subject. The Norsok standard D-010 and 117 – OLF recommended guidelines for well integrity have also been very informative during the study.

To be able to avoid SCP and at the same time improve well design, it is important to properly understand how SCP arises. Changing the casing shoe setting depth to a more suited depth or formation cannot alone eliminate SCP. To eliminate SCP a good conversion between Top of Cement (TOC) and setting depth of the previous casing shoe is required. The best way of avoiding SCP because of casing shoe setting depth is to make a thorough investigation of the underground and carefully choose the setting depth.

Sammendrag

En studie utført av petroleumstilsynet i 2006 viste at rundt 20 % av brønnene på den norske kontinentalsokkelen hadde indikasjon på brønnintegritetsproblemer. De fleste problemene var relatert til barriere svikt i sikkerhetsventiler i ringrommet, produksjonsrør, sement og foringsrør. Trykkoppbygning i Ringrommet (SCP) er en av hovedindikatorene på at en brønn har integritets problemer. Økt forståelse på området kan føre til brønner med bedre design og integritet i fremtiden.

Denne oppgaven omhandler først og fremst sammenhengen mellom settedybden på foringsrøret og forekomst av SCP under produksjon. Innledningsvis er prinsippene og de vanligste årsakene for SCP beskrevet. Primær og sekundær barrierekonvoluttene er viktige elementer som må fungere for å unngå trykkoppbygning. Det gis derfor en innføring i hvordan disse er bygd opp for en brønn i produksjon. For å kunne sammenligne boring og produksjon, og finne forbedringsmuligheter er den konvensjonelle metoden for valg av settedybde beskrevet.

Valg av settedybde avhenger av mange faktorer og det er viktig at dataene man arbeider med er mest mulig nøyaktig. Formasjonsstyrke er en meget viktig faktor og har mye å si for om settedybden er gunstig. Hvordan formasjonsstyrke kan bestemmes ved hjelp av integritetstester er derfor kort beskrevet.

Forskjellige generiske tilfeller ble undersøkt for å finne sammenhengen mellom settedybde og forekomst av SCP. Til hvert tilfelle er det fremstilt et forslag til hvordan foringrørsplanen kan revideres slik at muligheten for SCP reduseres. Informasjon rundt temaet er funnet i artikler, hefter og eldre rapporter. Norsok standarden D-010 og 117 – OLF anbefalte retningslinjer for brønnintegritet har òg vært til stor hjelp under arbeidet.

For å være best mulig rustet til å unngå SCP og å forbedre brønnintegriteten er det viktig å ha en best mulig forståelse for hvordan SCP oppstår. Å endre foringsrørskoens settedybde til en bedre egnet dybde kan ikke alene fjerne SCP. SCP som oppstår på grunn av settedybde er ofte et resultat av dårlig konversjon mellom topp av sement kolonne og settedybden til det foregående foringsrøret. Den beste måten å forebygge SCP med opphav i settedybde er å foreta grundige undersøkelser av undergrunnen og velge settedybden med omhu.

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1 Introduction

In 2006 a ''pilot well integrity survey'' was performed by the Petroleum Safety Authority Norway. The objective of the project was to determine to what extent wells on the Norwegian Continental Shelf suffer from integrity problems, the main issues and challenges. The survey would be used to ensure safe wells (Vignes, et al., 2006).

PSA categorized the wells suffering from an integrity problem by failure type. Most of the problems were related to well barrier failures in tubing, annulus safety valve, cement and casing. Figure 1.1 illustrates number of wells with the different barrier element failure types.

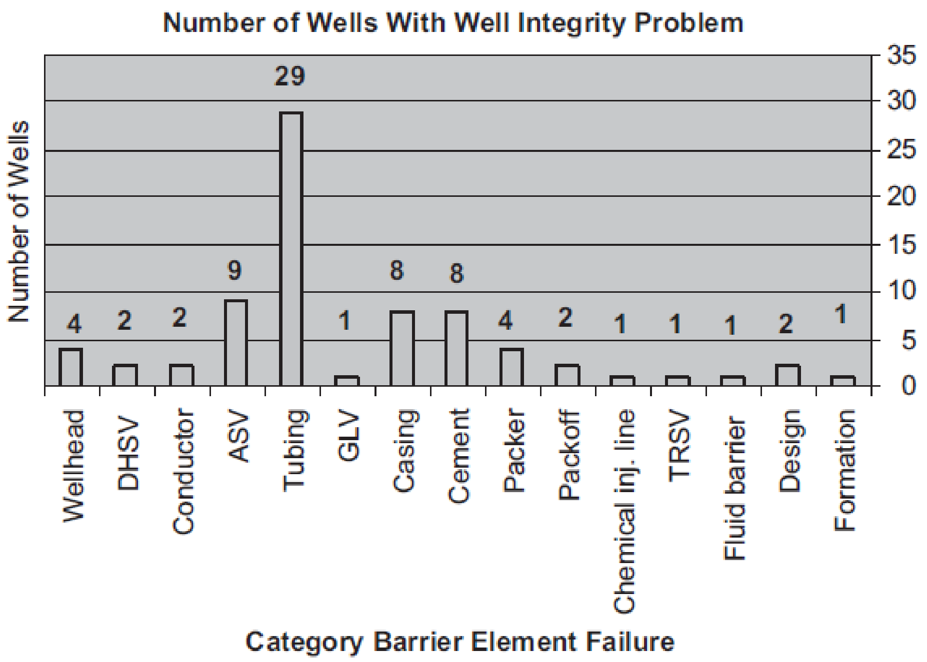


Figure 1.1: Number of wells suffering from different barrier element failure. (Vignes & Aadnoy 2008)

Seven companies were contacted and asked to share information concerning well conditions on pre-selected offshore facilities. To get a representative selection of wells both injectors and producers were assessed. The range of wells varied in age and had different development categories. The study showed that about 20 % of the wells were suffering from well integrity problems (Vignes, et al., 2006).

According to the Norsok standard D-010 well integrity is defined as; "application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well." If formation fluids are allowed to flow uncontrolled they might find a way to enter the annulus and cause pressure build up, i.e. sustained casing pressure. SCP is one of the main indicators and the most common reason for a well to be assigned of having a significant well integrity problem. As about 20 % of wells on the NCS may be suffering from integrity problems, ability to control and eliminate SCP may be a key element in getting rid of integrity problems and ensure safe wells.

The Norwegian Oil Industry Association (OLF) defines sustained casing pressure as; "pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by temperature fluctuations or imposed by the operator" (OLF - 117).

The worst case scenario that may arise as a result of SCP is a blowout that can cause damage to the platform, put lives at risk and harm the environment. A solution on eliminating SCP will reduce the number of wells suffering from well integrity problems and is therefore of common interest.

In the literature well design is mainly based on the drilling phase. Adjustments and precautions are based on happenings and problems that may arise during drilling. The operational conditions the well is exposed to during drilling and production is quite different and requires different qualities from the well. Very little information exists on the relation between the production phase and SCP. If both drilling and production not are taken into consideration when the well is drilled one may develop problems like SCP.

Sustained casing pressure may have many reasons of origin, but not all causes are thoroughly investigated. Unfavorable casing shoe depth is a source to SCP that should be better investigated.

An operator on the NCS has performed a survey of their wells and categorized them after the color system. As much as 70% of their wells that were categorized as orange might have had integrity problems related to the conversion between casing shoe setting depth and TOC of previous casing string.[1] How wells are categorized with different colors in the "traffic light system" is explanation is Appendix A.

The objective of this thesis is to find out to how unfavorable intermediate casing shoe depth may cause SCP and how it may be avoided. A proposal on how casing shoe setting depth can be chosen differently to avoid SCP will be presented. The proposal will be based on comparison of preferred setting depth from a drilling and production point of view.

[1] Information acquired through personal communication with Torbjørn Vrålstad at Sintef Petroleum Research

2 Sustained Casing Pressure

Sustained casing pressure is defined by OLF as: "pressure in any well annulus that is measurable at the wellhead and rebuilds when bled down, not caused solely by temperature fluctuations or imposed by the operator" (OLF – 117 2011).

If all well barriers are intact, the downhole equipment is undamaged and the cement job is fulfilling the Norsok standard, sustained casing pressure should not occur. Unfortunately this is not always the case and SCP is allowed to arise due to failure in one or more of the well barrier elements. Depending on how severe the integrity problem is, the well is assigned a color based on the "traffic light system". Green indicates a healthy well while red indicates a well where both barrier envelopes are damaged. Yellow and orange indicates a condition in between. The traffic light categorization is more detailed described in Appendix A.

During installation damage to the equipment may occur. Casing strings and production tubing may get broken during setting and downhole operations. Casing connections and packers which shall seal the well may not be tight causing leaks. SCP may also be caused by migration of fluids from formations along the wellbore into the well. According OLF 117 SCP caused by influx of fluids from formation zones along the wellbore causes the most challenging situations to manage and eliminate.

Once a leak path is established and there is a pressure difference, nature will try to equalize the pressure. SCP may be hard to remove because of constantly migrating fluid from the source. It can often be controlled by surveillance and regularly bleedoff operations. The symptoms may be removed for a while but pressure will usually rebuild. How fast the pressure rebuilds depends on the pressure difference and the size of the leak path.

The leak rate should not be neglected when the risks associated with SCP occurrence is evaluated. The time it takes for the pressure to rebuild after a bleedoff operation is measured to determine the extent and dimension of the leak. If sand or other particles are present in the fluid the magnitude of the leakage can quickly escalate because of erosion. When the potential hazard posed by the SCP is determined, both leak rate and magnitude of the pressure should be taken into consideration when determining how the leak rate should be dealt with (Bourgoyne et al. 1999).

There are many examples from the industry where SCP has been detected and the risk involved underestimated. Figure 2.1 shows a blowout resulting from SCP. In the technical report "A Review of Sustained Casing Pressure Occurring on the OCS" by Adam T. Bourgoyne et al. some examples from the industry are mentioned. When SCP was detected the platform applied for, and was granted a departure from the Mineral Management Service (MMS). Production continued as normal and the SCP was monitored.

In one of the cases two wells that had been producing for about six years developed SCP on the production casing. Since the shut-in casing pressure was 3400 psi and the maximum internal yield was 6900 psi the operator argued that it was safe to continue the operation and a departure was granted. After producing for two more years a blowout occurred between production casing and surface casing. It is estimated that about 600 MMSCF of gas and 3200 Bbl. of condensate escaped the well during the 46 days the well was out of control. Pollution from the blowout was found on about four miles of beach. The platform tipped over when the well cratered and both platform and well had to be abandoned (Bourgoyne et al. 1999).

In another case SCP was found in the production tubing five years after production start. A departure was granted for one year. At the end of this period the pressure was ranging between 1400 and 1800 psi and the departure was renewed. After about six months the pressure started to fluctuate and bubbles were observed in the water below the platform. A blowout was confirmed in a side-tracked well. Before the well was killed by a relief well, the platform started to shift and settle because the ground below one of the platform legs had started to erode. 6,75*10E6 cubic feet of sand was needed to keep the platform stable during the relief well drilling operation. In all, the operation of gaining total control over the platform lasted for two years. During this time the other wells on the platform had to be temporarily shut down (Bourgoyne et al. 1999).

Figure 2.1: Picture of a blowout resulting from SCP (Bourgoyne et al. 1999).

2.1 Age Relation

In the survey performed by the PSA it was found a clear relation between the age of the wells and the occurrence of SCP. In Figure 2.2 it can be seen that the integrity issue on average is twice as high for wells from the early 1990's than for earlier drilled wells

Figure 2.2 indicates that wells from 1992 to 2006 represent a peak for integrity occurrence. What separates new wells from old wells may be the completion time. Focus on fast drilling and cementing may lead to a less precise performance of the job which again increases the probability of SCP. Modern wells may also be more prone to SCP because they are more complex than old wells. By using more advanced equipment in the wells, new potential sources of errors that may lead to SCP are introduced. Of the 406 wells that were evaluated, 75 were found to be suffering from an integrity problem.

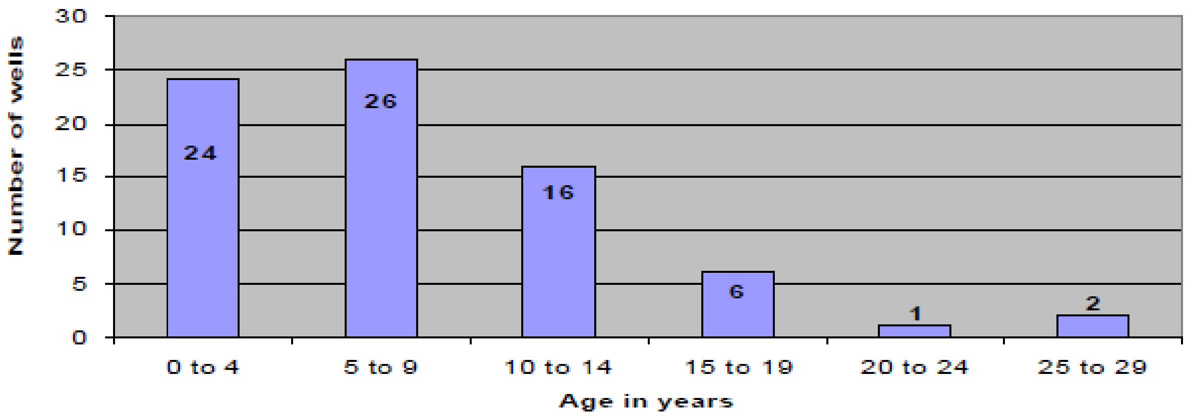


Figure 2.2: Age of wells with integrity issues. 75 out of 406 wells show integrity problems. The majority of these wells are from the early 1990's (Vignes et al. 2006).

2.2 Leak Source

Sustained casing pressure may have many reasons of origin. Figure 2.3 shows some of the different leak paths that can develop within a well. Some most common failures resulting in SCP are leaks through casing or tubing, intrusion of fluids from surrounding formations and leaks through packers and wellhead seals (Vignes & Aadnoy 2008).

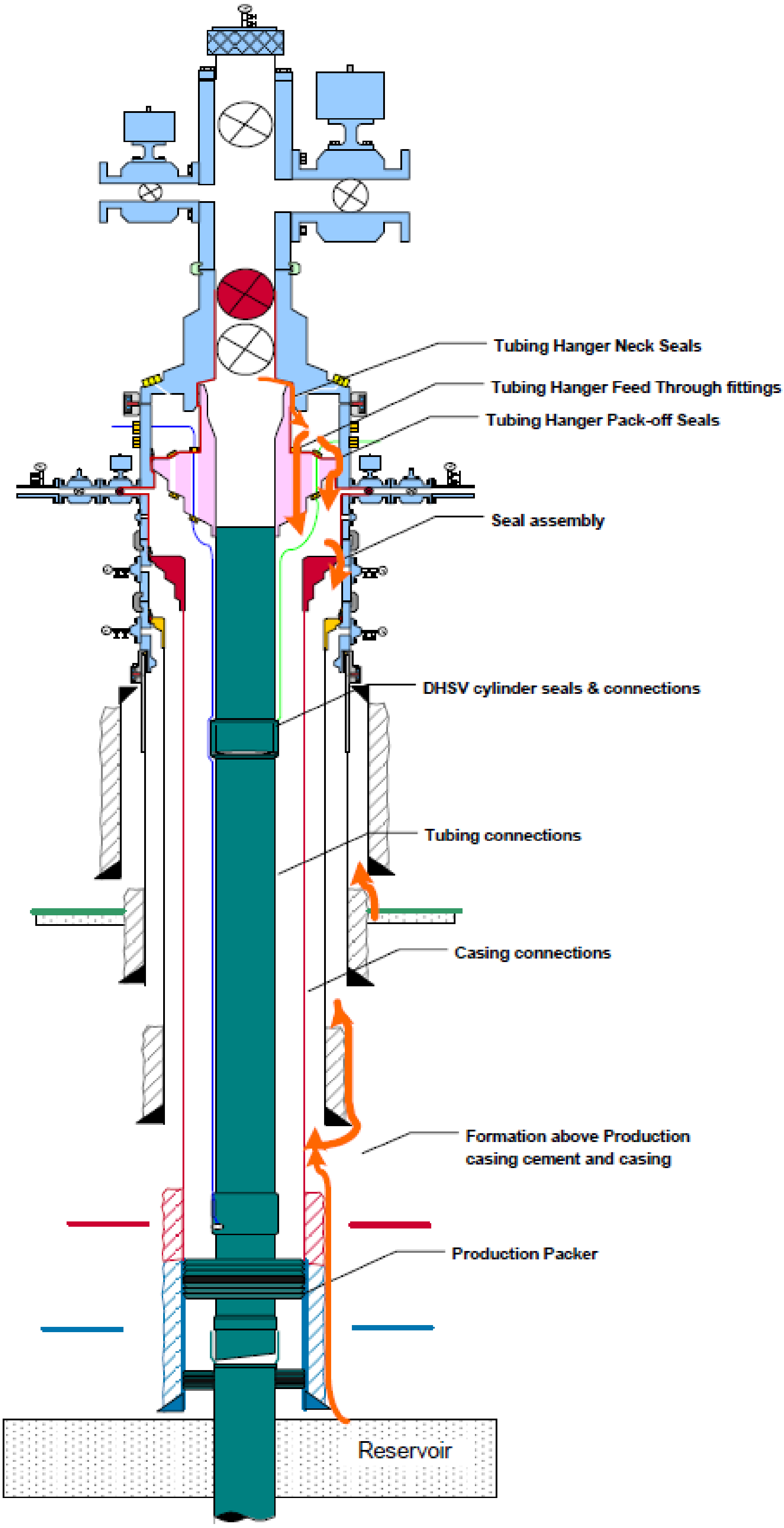


Figure 2.3: Different leak paths in a well (OLF-117 2011).

2.2.1 Leakage from Tubing and Casing

During setting and mechanical downhole operations cracks and rupture on casing and tubing may be inflicted by the equipment used leading to leakage and SCP. The well is experiencing large temperature differences that induce thermal stresses. As a result of these stresses the casing may crack. Poor thread connections and corrosion may also cause SCP (Bourgoyne et al. 1999). If corrosive agents such as H_2S, CO_2 or O_2 are present they should be monitored and be kept within the design limitations to reduce the chance of SCP (OLF – 117 2011).

The well is designed in such a way that the innermost casings are the strongest and the production casing is usually the only casing designed to withstand reservoir pressure (Bourgoyne et al. 1999). If a leak occurs in the production casing reservoir pressure is allowed to build up in annulus “b”. Since the next casing usually not is designed to withstand reservoir pressure it may burst and the pressure will work its way outwards in the well. If the pressure not is stopped an underground blowout may take place.

Experience from the industry has shown that the most catastrophic incidents because of SCP have been related to leakage in the production tubing. Worst case scenario is an underground blowout causing damage to the platform, putting workers in danger and polluting the environment (Bourgoyne et al. 1999).

Different methods are developed to identify leaks in the well. In one of the methods the pressure in the inner string is varied while it is observed if there is any corresponding pressure response in adjacent strings. Another method is to perform a bleedoff test and see whether the pressure rebuilds. If it does, SCP is present. If the leak is of serious extent it can be identified from production data by plotting tubing and casing pressure versus time (Bourgoyne et al. 1999).

The annuli have been denoted alphabetically where the first annulus between production tubing and production casing is named annulus “a”. The next annulus between production casing and the intermediate is named annulus “b” and so on. Figure 2.4 shows a simple well design with conductor casing, surface casing, intermediate casing, production casing, production liner and tubing. Primary barrier is marked with blue and secondary barrier with red color. The names of the annuli “a”, “b”, “c” and “d” are indicated on their respective annulus. This well design will be used as basis in the example scenarios presented later in the report.

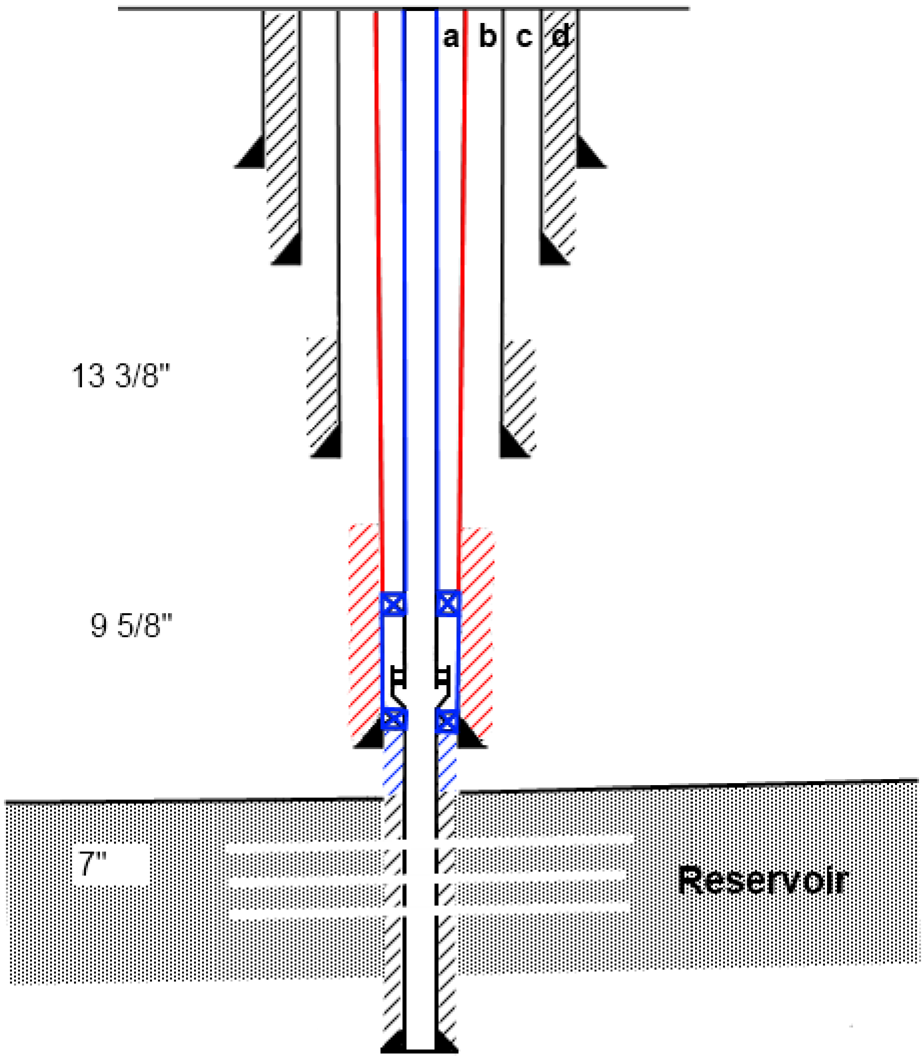


Figure 2.4: Simple well sketch showing different casing strings, production tubing and liner. The letters "a", "b", "c" and "d" are indicating different annuli. Primary barrier is marked with blue and secondary barrier with red color.

2.2.2 Leaks due to Cement Failure

Cement outside the casing is set to provide an impermeable, zonal isolating sheet that is supposed to last throughout the lifetime of the well (Bellabarba et al. 2008). Many things can disturb and harm the cement sheet during the cementing process. The cement may become brittle and may not respond very well to pressure and temperature induced loads. The result may be cracking and forming of channels in the cement.

There are mainly two reasons SCP occur as a result of cement failure; poor primary cement and damage to the primary cement. From the cement is set in a liquid form till it obtains its final condition as a solid it goes through different phases. During this process there are many parameters contributing that may lead to defects in in the cement (Bourgoyne et al. 1999).

Even though the primary cement job is well performed, there are still hazards that may cause damage to the cement after it is set creating flow paths. Casing and cement reacts in different manners when they are exposed to pressure and temperature changes.

If the cement expands more than the casing during temperature and pressure loads, they may get separated generating a micro annulus. An illustration of a micro annulus is shown in Figure 2.5. If the micro annulus extends over large intervals, it may provide a good path for fluid to migrate and development of SCP. Mechanical shocks occurring during tripping may also result in micro annuli generation because of weakening the casing-cement bond (Bourgoyne et al. 1999).

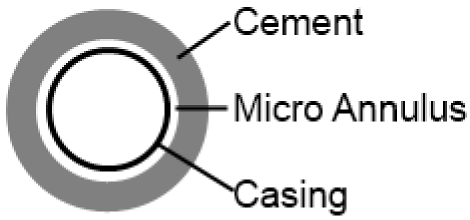


Figure 2.5: Casing and cement are separated creating a micro annulus

Invasion of formation fluids into the annulus occurs when annulus pressure is lower than the formation pressure. In Figure 2.6 the formation pressure, p1 is larger than the pressure provided by the cement slurry column, p2. Formation fluids are therefore allowed to migrate into the cement slurry. The fluids can migrate all the way to the surface or to a formation with lower pressure which also is illustrated in Figure 2.6. To avoid flow from a formation into the cement slurry it is important to ensure that the slurry density provides larger pressure than the formation. On the other hand it is important that the slurry pressure not exceeds the formation fracture gradient to avoid fracturing and loss of slurry and pressure (Bonett 1996).

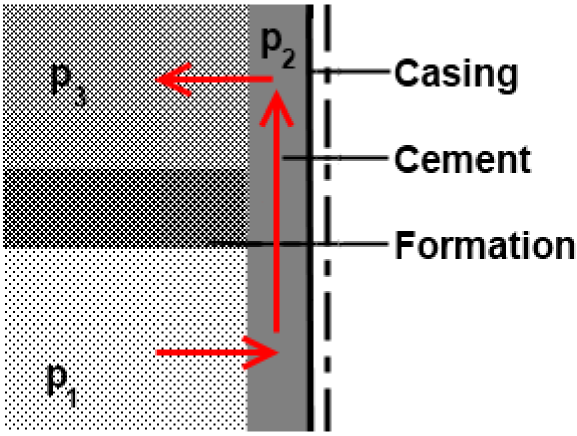


Figure 2.6: Migration of formation fluids into the cement slurry and low pressure formation because of larger pressure in in the lower formation than in the cement slurry.

Channels formed at liner top and cement shoe can be repaired by squeeze cementing. The channels in between can generally not be repaired. It is therefore important to ensure that the primary cementing is of good quality. Some factors contributing in cementing is mud characteristics, pore pressure and fracture pressure in zones that can get connected through channels and create a cross flow (Bourgoyne et al. 1999).

As the cement gels the ability to transmit hydrostatic pressure decreases. This may allow fluids to enter the cement and form channels during the setting process. Fluids can originate from either the reservoir or other fluid containing formations. No matter how well the cement operation is performed, there is no guarantee that the cement is able to resist invasion during the hydration process (Bourgoyne et al. 1999).

If the well not is cemented according to the latest version of the Norsok standard D-010 the cement may not qualify as a well barrier element. The requirements can be seen in Table B. 8 in Appendix B. A common reason for why some old wells may not fulfill the Norsok standard D-010 may be that they not are cemented above the production packer. If a leak occurs between TOC and the production packer the fluid is outside both barrier envelopes. There is nothing to prevent the fluid from entering the formation and in worst case flow to the surface. Examples on leaks occurring as a result of cement not covering the production packer are presented in case 1 and case 4 later in the report.

2.2.3 Preventive Methods

It is better and easier to prevent SCP than getting rid of it. If a factor that may cause SCP is discovered action should be taken to remove it.

If there are corrosive agents or sand is present in the produced fluid the well should be monitored. Special attention should also be given to make sure it satisfies the production criteria. Erosion and corrosion can be can be monitored through surface samples and by downhole inspection such as calliper (OLF – 117 2011).

One should also try to avoid unnecessary loading of the well. Start up and shut in of a well is examples of situations where the well is put under unfavorable conditions. Activities causing significant changes in temperature and pressure within a short period of time are also exposing the well to unfavorable conditions. To avoid defects leading to SCP because of the situations described above, procedures on how to perform and handle these situations should be developed (OLF – 117 2011).

When the cement job outside the production casing is planned it is important to consider both pore and fracture pressure to be able to design a high enough TOC. It is important that TOC is so high that the requirements for setting of the production packer can be acquired with a good margin.

If two fluid bearing zones are supposed to be drilled through with the same mud, precaution has to be taken with regards to the cementing. It is important to make sure that the pore pressure in the lower zone not is too close to the fracture pressure in the upper zone. Figure 2.7 shows an example where pore pressure in layer 2 is larger than the fracture pressure in layer 1. As a result channels are forming in the cement before it gels and a crossflow may form between the two layers. It is also important that as much as possible of the mud cake is removed to develop a good cement/formation bond. Residual mud cake may create a route for gas to flow up the annulus and lead to SCP.

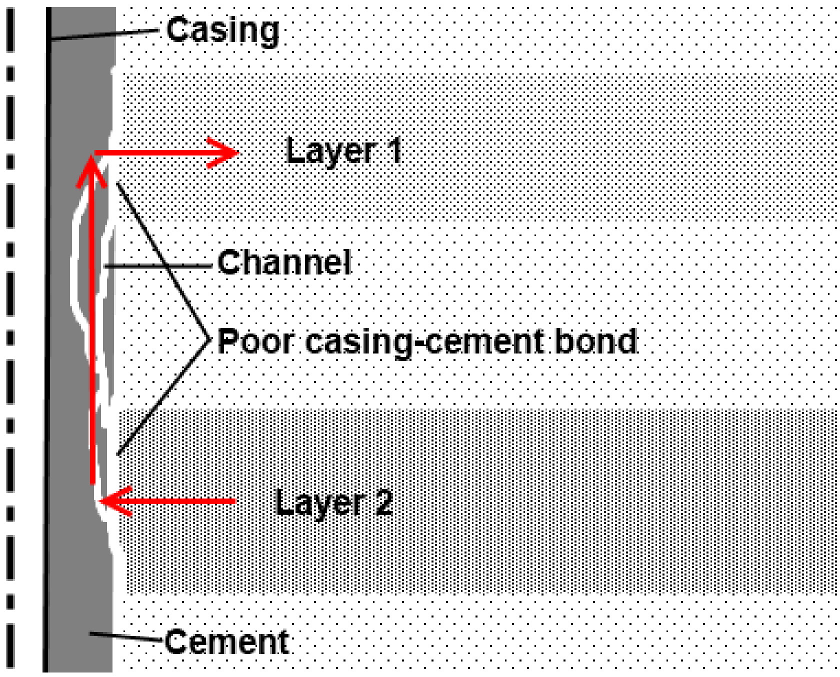


Figure 2.7: Pore pressure in layer 2 is larger than the fracturing pressure in layer 1. As a result layer one may fracture and a crossflow between the two layers is formed.

3 Well barriers

There are many dangers related to drilling and producing an oil well. To minimize the risk of uncontrolled flow of fluids into and out of the well certain precautions have to be made. The most important is precaution may be to fulfill the requirements for the well barrier envelopes.

According the Norsok standard there should always be at least two independent barrier envelopes in place if a risk of uncontrolled outflow from the well to the external environment is present. A barrier envelope is made up of several Well Barrier Elements (WBE). Together the WBEs form a closed, sealed system preventing pressure from entering and exiting the well. To qualify as a well barrier envelope, each barrier element has to be tested in accordance with the Norsok standard D – 010. The requirements can be found in Appendix B.

Figure 3.1 illustrates where the primary and secondary barrier envelope is located during production. Primary barrier is marked with blue color and secondary barrier with red color. In this case the primary barrier envelope is made up of, cement behind the production liner, the production liner, liner hanger and packer, 9 5/8 in. casing between liner hanger packer and production packer, production packer, production tubing and the surface-controlled subsurface safety valve. The secondary barrier envelope is made up of the 9 5/8 in. cement, 9 5/8 in. casing, 9 5/8 in. casing hanger with seal assembly, wellhead/annulus access valves, tubing hanger with seals and X-mas tree access valves.

It is important to remember that the barrier envelope changes with the different well stages. Drilling and Production require different qualities form the barrier envelope. The barriers which are valid for drilling may therefore not be used in production. An example is drilling fluid which is the primary barrier during drilling but not is present during production.

If the primary barrier fails the secondary barrier is redefined to be the primary barrier. Ideally it should be possible to redefine the casing and cement outside the original secondary barrier to become the new secondary barrier. TOC of the next casing and setting depth of the previous casing along with formation properties decides whether a redefinition is possible or not. In Figure 3.1 a redefinition of the 13 3/8 in. casing can be made if the formation present in the open hole section qualify as a WBE.

If unwanted fluid migration cannot be avoided, it is preferable to keep it within the barrier envelopes so that SCP can be monitored, controlled and hopefully eliminated. If the fluid is allowed to migrate into an annulus outside the barrier envelopes or into a formation it may be hard to detect and the outcome may be catastrophic. Inside the annulus pressure may build up and exceed the design limitations of the equipment resulting in a blowout. If the fluid flows into the formation, the formation itself and groundwater may get polluted. In a case where no sealing rock is present the fluid may find a way to migrate all the way to the surface. If fluid is allowed to flow to the surface it may damage to the environment and be hazardous to the platform and the people on board.

Having designed and constructed the well in such a way that the next casing string and cement can be redefined as a barrier is therefore a huge advantage. It increases the probability to maintain control in a situation with SCP.

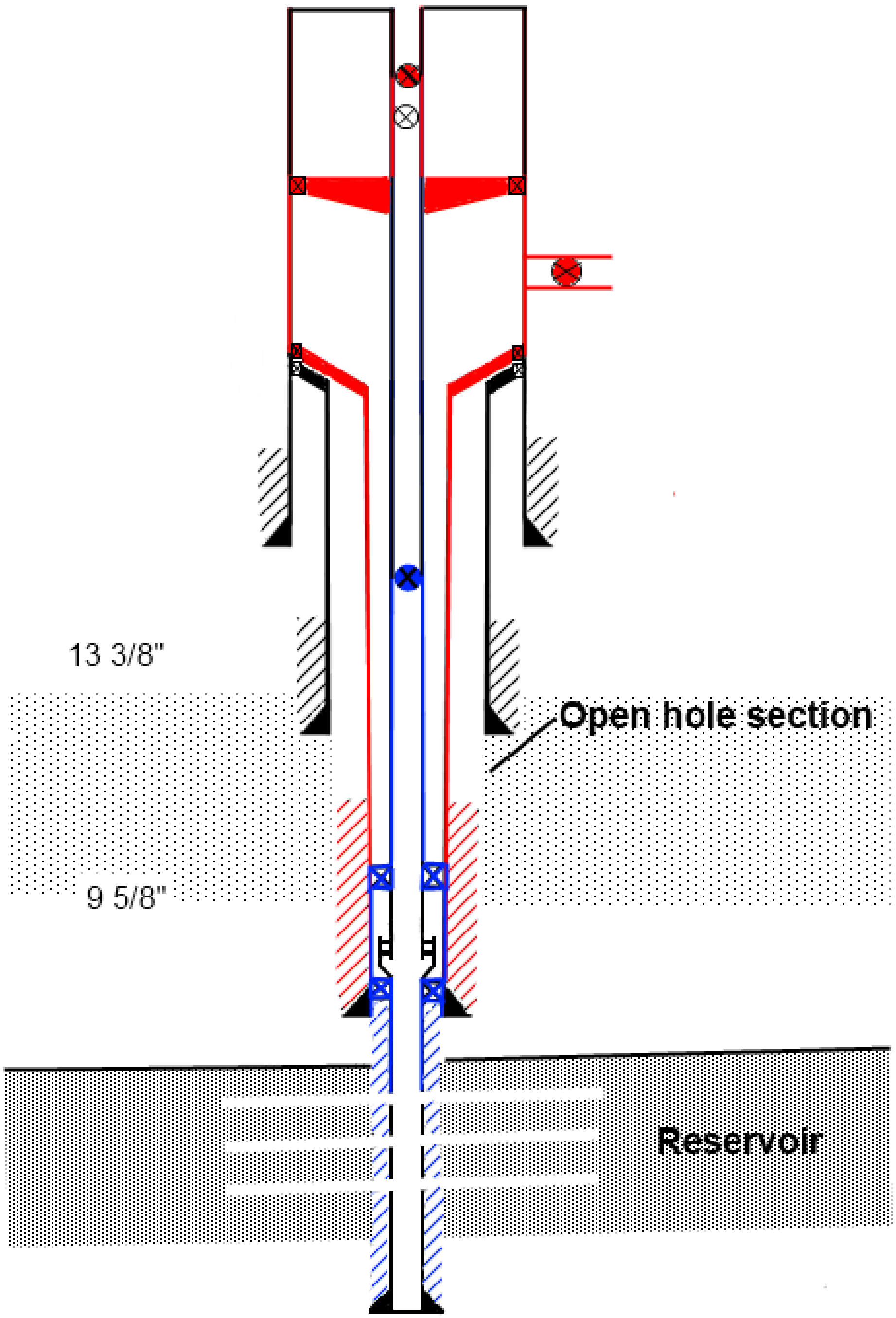


Figure 3.1: Primary barrier envelope is shown with blue color and secondary barrier envelope with red color.

3.1 The Well Barrier Schematic

To have important and mutually dependent information gathered in the same place may prevent misunderstandings and unfortunate incidents. A properly filled out Well Barrier Schematic (WBS) makes this possible.

It is important to have a proper WBS so that it is clear what is defined as primary and secondary barrier. In 2007 no common practice regarding the use of WBS existed, the well integrity forum (WIF), which is a part of OLF, was therefor assigned the task to develop a common well barrier schematic proposal. The schematic contains a minimum of data to ensure that any weaknesses are made aware of and that the actual downhole situation is shown. The data have to be filled in by the operator. When the well conditions are changing the WBS should be updated. An illustration of a standard WBS is shown in Figure 3.2. Primary and secondary barrier are separated by using different colors. According to OLF – 117, "Recommended Guidelines for Well Integrity", the minimum data a WBS should contain are;

1. *The formation strength should be indicated for formation within the barrier envelopes.*
2. *Reservoirs should be on the drawing.*
3. *Each barrier element in both barrier envelopes should be presented in a table along with its initial integrity-verification test results.*
4. *Depths should be shown relatively correct according to each barrier element on the drawing.*
5. *All casing and cement, including the surface casing, should be on the drawing and labeled with its size.*
6. *There should be separate fields for the following well information: installation, well name, well type, well status, rev. no and date, "Prepared by", "Verified by".*
7. *Include a note field for important well integrity information.*

Because formations in an open hole section may be exposed to reservoir pressure it is important to always include the formation strength in the well barrier schematic. Knowing the formation strength it is easy to calculate whether or not the formation can handle the pressure arising during a kick. The formation strength limitation should also be included when operational limitations of the well are determined. Methods of determining the these limits can be physical measurements made during drilling of the well, core samples, downhole logs or correlations based on historical field data (OLF – 117 2011).

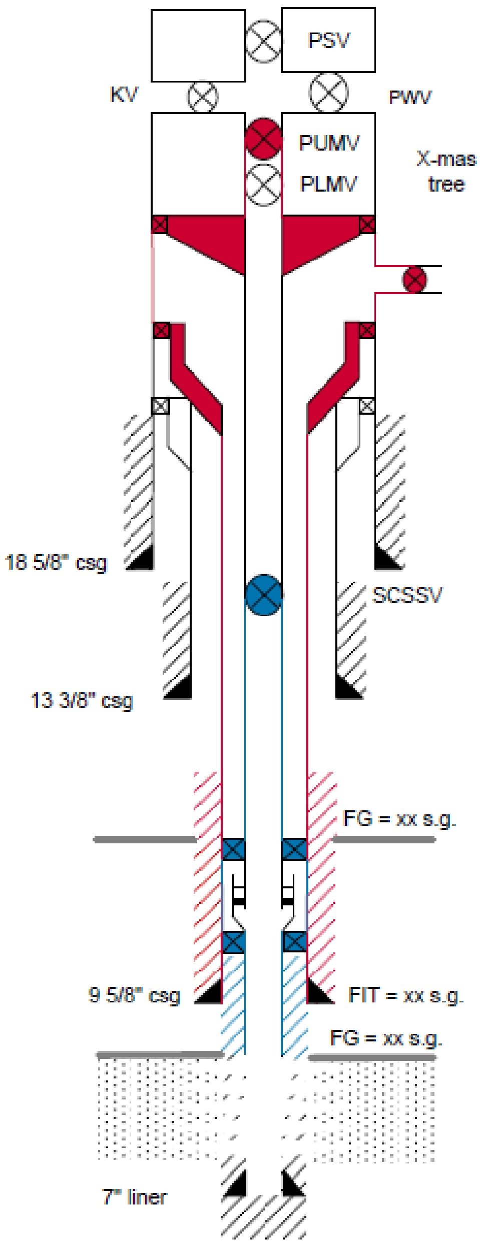
If formations in open hole sections are used as a WBE it is important to know where they are located. Knowing their location makes it easier to avoid situations where they are exposed to pressure exceeding their strength. If the formation strength is exceeded it may result in fracturing and leak into the surrounding formation. The fluid may also find its way into the next annulus (OLF – 117 2011).

It is not unusual that formations are present in within barrier envelopes representing a WBE. To qualify as a well barrier the formation must be able to withstand any pressure it may be exposed during the life of the well.

It is important that the depths are shown relatively correct in relation to the WBE on the WBS. If there is damage on the casing below the production packer it is important to know if the packer is set in cemented casing or not. If it is not set in cemented casing the chance of a leak leading to SCP is much larger than if it was set in cemented casing. To know that the casing setting depth is corresponding to the formation strength is important when deciding whether the open hole sections can handle large pressures (OLF – 117 2011).

Formation strength and relative location of different casing strings and belonging cement should be as exact as possible. The robustness estimate of the well will be better the more exact the given information is. With these data known the chance of a misinterpretation is also less likely (OLF – 117 2011).

WELL BARRIER SCHEMATIC



Well information		
Installation:	xxxxx	
Well no.:	xx/xx-xx	
Well type:	e.g.Oil producer	
Well status:	e.g. Operational	
Revision no. / Date:	x	xx.xx.xxxx
Prepared:	xxxxx	
Verified/Approved:	xxxxx	

Well barrier elements	Verification of barrier elements
PRIMARY	
7 " liner cement	xx bar with xx sg fluid Method: prognosed / measured TOC: xx mMD Method: volume control / logs e.g. CBL xx bonding at xx mMD
7" liner	xx bar with xx sg fluid
7" liner hanger packer	xx bar with xx sg fluid
9 5/8" casing between liner hanger packer and production packer	xx bar with xx sg fluid
Production packer	xx bar with xx sg fluid
Production tubing	xx bar with xx sg fluid
SCSSV	Inflow test to xx bar
SECONDARY	
9 5/8" casing cement	FIT to xx sg EMW. Method: prognosed / measured TOC: xx mMD above prod.packer / csg.shoe. Method: volume control / logs e.g. CBL xx bonding at xx mMD
9 5/8" casing	xx bar with xx sg fluid
9 5/8" casing hanger with seal assembly	xx bar with xx sg fluid
Wellhead / annulus access valve	xx bar with xx sg fluid
Tubing hanger with seals	xx bar with xx sg fluid
X-mas tree valves	xx bar with xx sg fluid

Reference / Disp. no. well integrity issues	Comments / Notes:
N/A	

Logo

Figure 3.2: A well barrier schematic illustrating recommended guidelines for what should be included in a WBS. Data have to be filled out where xx is stated for a real well (OLF – 117 2011).

4 Casing Shoe Selection

Common practice today is usually to choose casing shoe setting depth based on the drilling process. Selection of casing shoe depth may have different optimal solutions for drilling and production.

4.1 Well Design

When drilling of a new well is planned it is advantageous to know the pore pressure- and fracture gradient of the formation. These data can be obtained from for example nearby already drilled wells. Knowing the pressure and fracture profile a mud window, as shown in Figure 4.1, can be made. In the diagram the gradients are plotted versus depth. Based on these data a program of bit sizes, casing sizes, steel grades and setting depth can be made.

Because of economic reasons casing strings can be made up of different steel grades, wall thickness and coupling types. The potential savings of selecting different steel grades in sections of the casing must be considered against additional risks. These risks are associated with performance of leak free tieback operations and additional wear resulting from longer exposure of the upper casing to rotation and translation of the drill string (Bourgoyne et al. 1986).

The combination of different steel grades may also have an important saying in how well the well resists SCP. In this thesis the aim is to find out how the setting depth influences the occurrence of SCP. The main focus will therefore be on selection of the setting depth and not on how different weight, grade and coupling types for the casing are chosen. If the well is drilled underbalanced the collapse pressure also has to be taken into consideration, this is also not included in the problem to be addressed in this thesis.

4.2 Setting Depth Based on mud weight

Deciding the setting depth of a casing string a number of elements has to be taken into consideration. Calculations are made to see whether the casing can take loads occurring during a kick or underground blowout.

First step is to design a casing program based on mud weight. A safety margin of 0,5 ppg (0,06 s.g.) is commonly used for both pore pressure and fracture gradient to ensure a safe operation without kicks and fracturing of the formation (Bourgoyne 1986). A trip margin of 0,5 ppg is plotted in Figure 4.1 with dashed lines. The setting depth has a strong correlation with the mud density used to drill a section. As the well is drilled, the pore pressure is increasing and the pressure difference between mud gradient end pore pressure gradient is decreasing. To prevent the two gradient lines from crossing and avoiding a kick the casing shoe is set and the mud weight is increased.

Some places, like in North Sea the mud window may be very tight and drilling a well with a safety margin of 0,5 ppg would be impossible. To enable drilling in such places the mud window needs to be optimized by using a smaller safety margins. In North Sea it is common practice to use a safety margin of 0,08 ppg (0,01 s.g.) for fracturing and 0,25 ppg (0,03 s.g.).

When designing a well it is common to start with the supposedly last section to be drilled. Mud weight equivalent to the pore pressure gradient in point "A" in Figure 4.1 is chosen to prevent inflow from the formation i.e. a kick. This mud density cannot be used to drill the whole well. At point "B" in Figure 4.1, the formation will have a fracture gradient equivalent to this weight. The intermediate casing shall protect the formation at this point and to surface from the pressure exerted on it from the mud. The intermediate casing therefore has to extend at least to point "B". Then the mud density needed to drill to point B and set the intermediate casing is chosen equivalent to the fluid density shown in point "C". Choosing mud density at point "C" implies that the surface casing has to be set at point "D" to avoid fracturing the formation. All points are if possible chosen on the safety margin line (Bourgoyne et al. 1986).

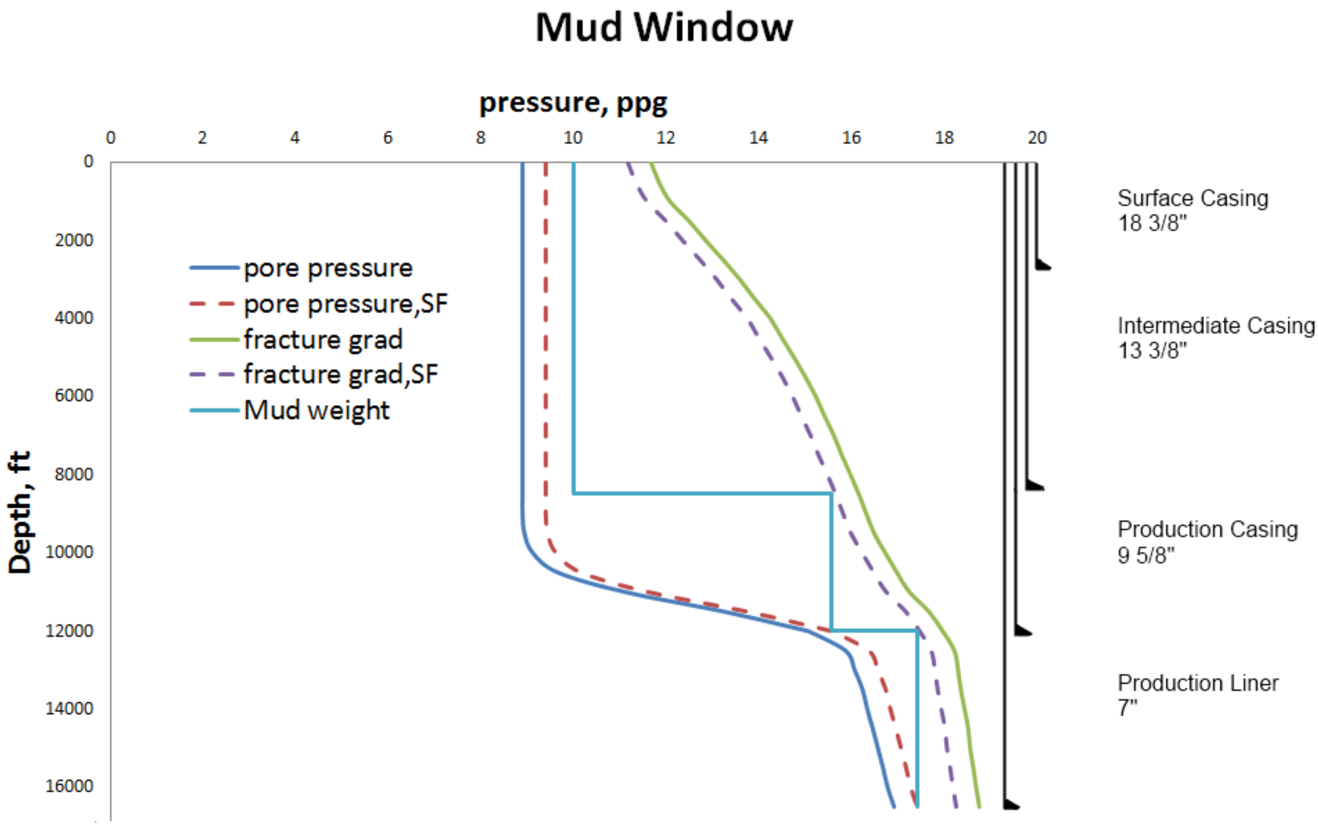


Figure 4.1: Mud Window with trip margin and correlating Well Design

Protection of fresh water aquifers, lost circulation zones, salt beds and low pressure zones which may cause stuck pipe are factors that needs to be taken into consideration and influence the setting depth. Setting depths obtained by using the method described above are shown in Table 4-1.

Table 4-1: Casing size and belonging setting depth based on mud weight.

Casing size (in.)	**Depth (ft.)**
7	16 500
9 5/8	12 000
13 3/8	8500
18 5/8	350

When the setting depth based on mud weight is found, the kick criterion may to be taken into consideration. Some changes probably have to be done to the casing setting depths to satisfy the new criterion.

4.3 Setting Depth Based on Kick Criterion

During drilling kicks from high pressure formations may be passed on the way to the reservoir. If the mud pressure cannot withstand the pressure from the formation, a kick may occur. By taking the kick criterion into consideration, the setting depth may be chosen so that the formation in which the casing is set can withstand the pressure it is exposed to during the kick.

Using this method it is important to do the evaluation based on pressure and not the pressure gradients (Aadnoy 2010). Pore pressure and fracture pressure are therefore plotted in psi versus depth. An example of pore pressure versus depth is shown in Figure 4.2.

If the well has been drilled to 12 000 feet and a kick takes place it should be designed to handle this. Assuming the formation fluid at this depth is a condensate with density 7,58 ppg (0,91 s.g.), constant density and no expansion during circulation. When the kick takes place the well will be filled with condensate and the pressure upward in the well will be reduced by the weight of this fluid (Aadnoy 2010).

In Figure 4.2 the kick fluid gradient is plotted. The point where it crosses the fracture pressure line indicates the new casing setting depth. Repeating this gives the other casing setting depths. Figure 4.2 shows where the new setting depths have to be to satisfy the kick criteria.

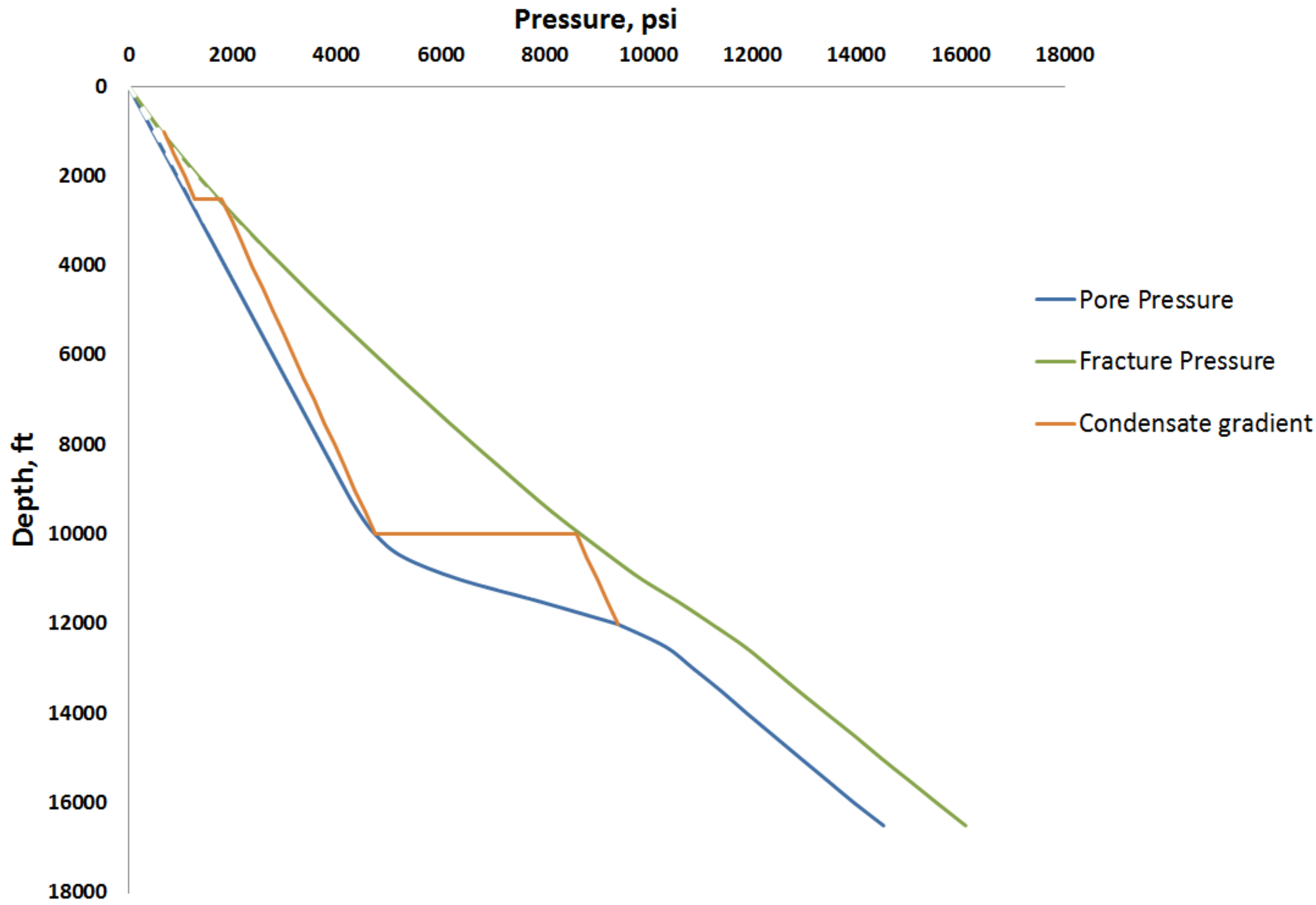


Figure 4.2: Setting depth based on kick criteria.

The new setting depths that are found using the kick criteria method are summarized in Table 4-2.

Table 4-2: Casing size and belonging setting depth based on kick criterion.

Casing size (in.)	Depth (ft.)
7	16 500
9 5/8	12 000
13 3/8	10 000
18 5/8	2500
30	1000

If the well is drilled from a floating drilling rig, the riser margin has to be taken into consideration deciding the casing setting depth. The riser margin is needed in case the drilling vessel has to be disconnected due to for example bad weather. In case of disconnection the hydrostatic head created by mud in the riser is replaced by the hydrostatic head of sea water. The pressure difference needs to be balanced. During regular drilling this is done by applying a heavier mud. The over pressure created is called the riser margin. Including the riser margin in the calculations will affect the casing shoe setting depth (Aadnoy 2010).

Numerical Example

These data are based on the mud window in chapter 4.2 "Setting Depth Based on mud weight". Assuming a kick takes place at 16 500 ft. and the kick fluid is a condensate with density of 6,34 ppg (0,76 s.g.) can the formation in which the previous casing shoe is set handle the pressure? The density of the condensate is assumed constant and there is no expansion during circulation.

Table 4-3: Information on casing size, casing shoe setting depth, pore pressure and fracture pressure.

Casing size (in.)	Depth (ft.)	Pore Pressure (psi)	Fracture Pressure (psi)
7	16 500	14 517	16 096
9 5/8	12 000	9404	11 213
13 3/8	8500	3934	7143
18 5/8	350	-	-

<u>Calculating pressure at 12 000 ft. after the kick has taken place:</u>

Pressure@12 000 ft. = Pore Pressure@16 500 – weight of condensate column

Pressure@12 000 ft. = 14 517 psi – 0,052*(16 500- 12 000) ft. * 6,34 ppg

Pressure@12 000 ft. = 13 033 psi

From Table 4-3 it is seen that the formation at 12 000 ft. cannot take more than 11 213 psi before it fractures. If the primary barrier fails (which is what happens in Case 4: Leak below Production Casing Shoe), and the formation at 12 000 ft. is exposed to reservoir pressure the formation will fracture allowing fluids to flow out of the well.

To find out at what depth the previous casing needs to be set at, the same method as deciding setting depth based on the kick criterion in chapter 4.3 can be used. The condensate gradient is drawn into a figure together with pore pressure and fracture pressure. From Figure 4.3 it can be seen that the production casing has to be set at 14 500 ft. or deeper to be able to resist the pressure generated in case of a blowout.

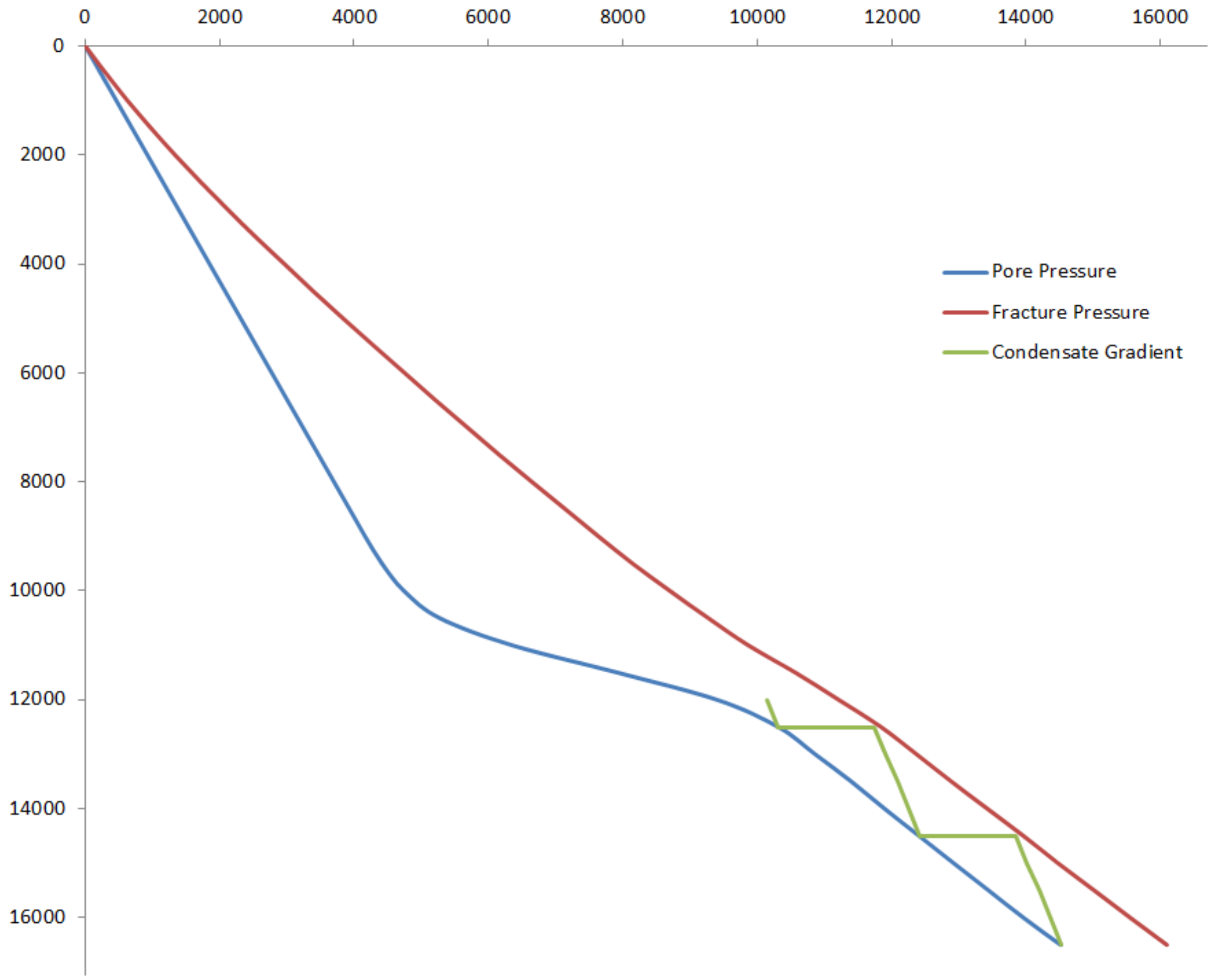


Figure 4.3: Condensate gradient drawn in the same figure as formation pore pressure and fracture pressure.

4.4 Additional Casing String

Sometimes, when production requirements are taken into consideration it may be necessary to insert an additional casing string to obtain an optimal well design. After inserting the additional casing string, drilling can be continued as planned.

If the extra casing string is inserted between a 20 in. conductor casing a 13 3/8 in. surface casing, a 16 in. casing string can be added without making any difference for the production casing. An 11 in. casing string can be placed between the 13 3/8 in. surface casing and the 9 5/8 in. production casing without having any influence on the production liner. If on the other hand an extra casing is required between the 9 5/8 in. production casing and the 7 in. production liner, a 7 in. production casing can be set resulting in a diameter decrease of the production liner to 5 1/2 in.

Since the purpose of an exploration well not is to extract large amounts of oil, the reduction in liner diameter may not affect the purpose of the well. For a production well the liner diameter may determine whether the well is able to produce as planned or not.

Figure 4.4 shows how setting the 9 5/8 in. casing shallower and inserting an extra 7 in. production casing string may allow a deeper setting depth. The dashed line indicates at what depth the previous casing string has to be set to allow the extra casing string to be set at the new depth. This can be useful if hazardous trouble zones requiring isolation are run into. It may also be necessary to set the casing shoe deeper because of formation strength.

Generally the formation fracture gradient is increasing with depth. This can be used if the initially planned setting depth cannot withstand the pressure that may arise during a kick. The larger formation strength obtained by setting the casing shoe deeper may satisfy the requirements and an underground blowout may be avoided.

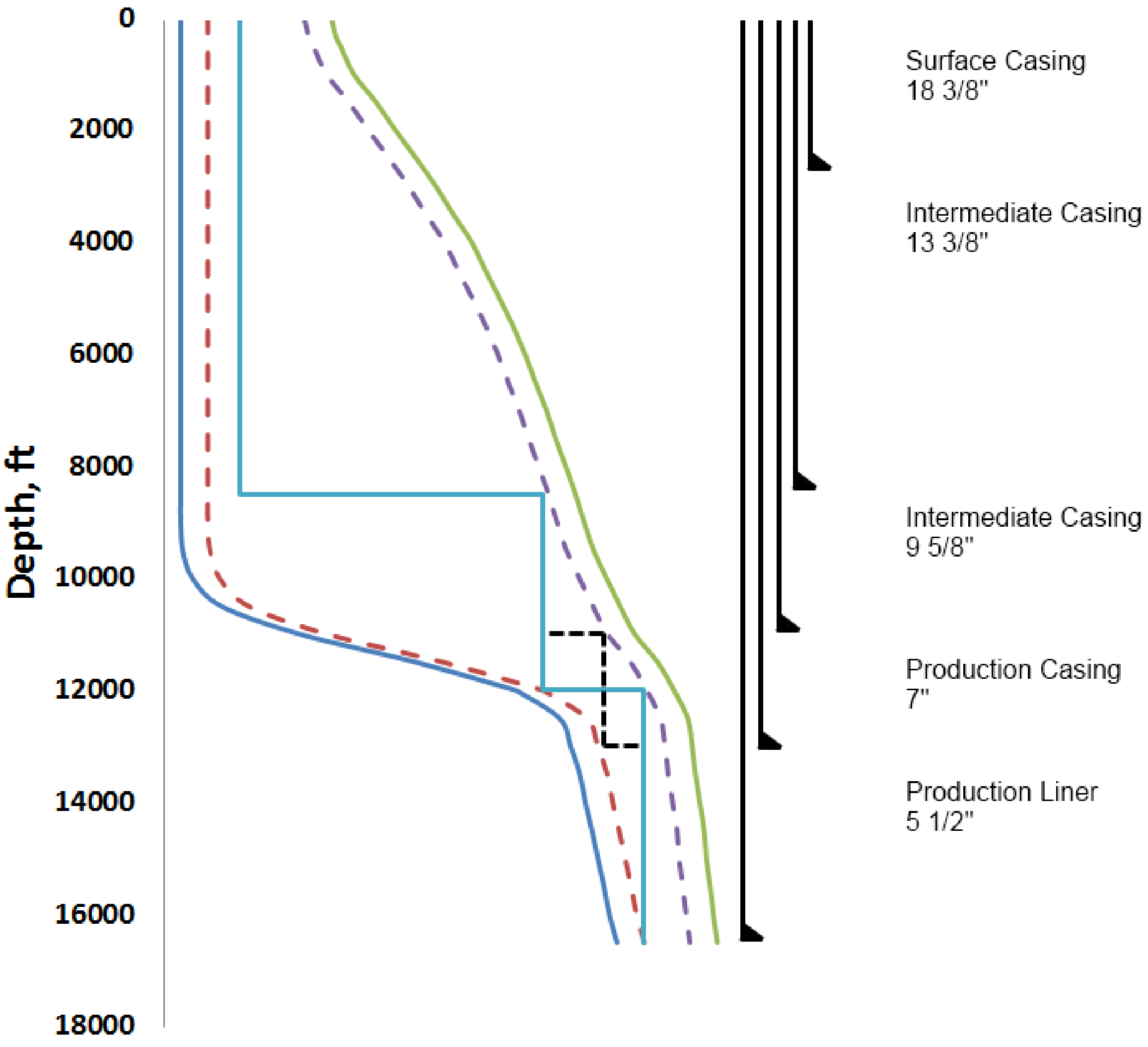


Figure 4.4: An extra intermediate casing string is utilized. Production casing size is therefore reduced from 7 in. to 5 in.

As previously mentioned, increased number of casing strings may result in smaller production tubing diameter and limited production. It is also time consuming to trip the drill string to change the bit and set the new casing. Before deciding to use an extra casing string the advantages must be weighed against the extra costs involved together with the reduced throughput a reduction in production tubing diameter will lead to.

Expandable casing or liner may sometimes be used instead of an extra casing string. The expandable casing does not hold the same pressure resistance as a conventional casing string. It may therefore be disadvantageous to use for this purpose since one of the objectives is to increase the pressure resistance in the casing.

A liner on the other hand can for example be used between the 20 in. and 13 3/8 in. or 13 3/8 in. and 9 5/8 in casing. By using a liner instead of a casing extending all the way to the surface steel costs may be greatly reduced. Using a liner requires additional tools and is a complex operation accompanied with additional risk. Pros and cons have to be weighted before choosing a liner instead of a casing going all the way to the top of the well (Schlumberger, ID: 1464).

If the extra casing needs to be set after the production casing it may be advantageous to let the casing string go all the way to the surface. This is to prevent the previous casing string (that usually can take less pressure) from experiencing reservoir pressure.[2]

4.5 Pressure Integrity Tests

Pressure integrity tests may be used to determine the formation strength and formation integrity. Knowing the formation strength at different depths may help choosing the most favorable casing shoe setting depth.

In chapter “4.2 Setting Depth Based on mud weight” it is shown how the setting depth is chosen based on a combination of pore pressure and fracture gradient. The fracture gradient is based on the different pressure integrity tests and is therefore strongly related to casing shoe setting depth. Having good formation integrity tests that can give good estimates for the formation strength is very important to be able to choose the best suited setting depth.

The recommendation from PSA to include formation strength in the WBS is relatively new and makes it easier to stay within the limitations. Exceeding the formation strength may lead to fracturing of the formation, leaks and uncontrolled SCP outside the barrier envelopes. The different methods used to obtain formation strength may have different accuracy and meaning. It is therefore very important to always include the method used to find the values in the WBS.

[2] Information acquired through personal communication with Sigbjørn Sangesland 18.05.2012.

In this chapter the leak of test (LOT), the extended leak of test (XLOT) and the formation integrity test (FIT), which all are used to describe the formation, will be briefly described.

4.5.1 Leak-off Test

The leak-off test is an important factor when the well integrity is evaluated. It is usually performed after a casing shoe is set to make sure the shoe and casing are fulfilling the requirements to well integrity.

Leak-off tests can be used to estimate the maximum pressure a casing shoe can withstand. Knowing this value, the maximum mud weight that can be used to drill the next section can be calculated (Addis et al. 1998). To make sure the cement and formation below the casing shoe can withstand the pressure exerted on them during drilling of the next section, they may also be leak-off tested (Bourgoyne et al. 1986).

The LOT is performed by closing the well at the surface and increasing the well pressure by pumping with a constant rate. The pumping is stopped when the test pressure is reached or the injection pressure starts to divert from the trend line. Figure 4.5 shows a typical leak-off test.

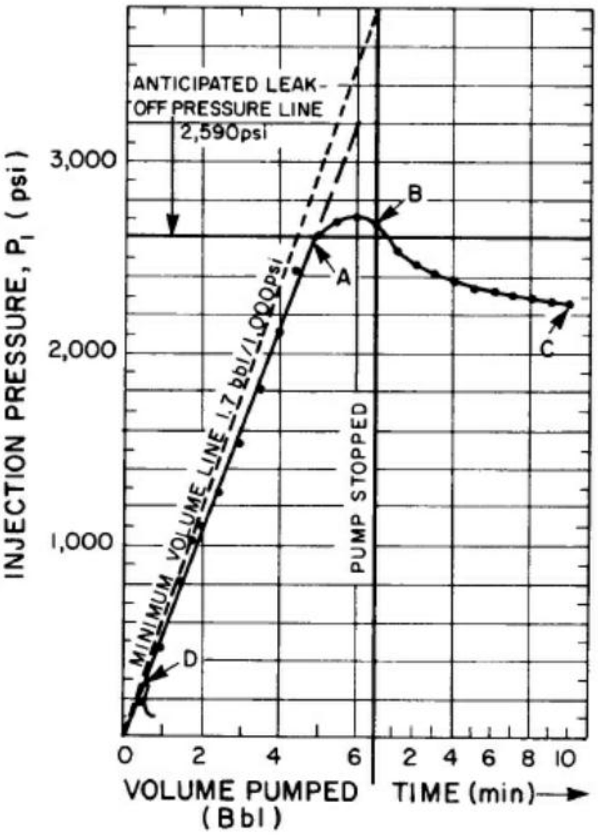


Figure 4.5: A typical leak off test (Bourgoyne et al. 1986).

Because of the constant pump rate, a plot of injection pressure versus pump rate will give a relatively straight line up to point “A” as seen in Figure 4.5. At point “A” the formation grains are starting to move apart allowing mud to flow into the formation. Because mud is escaping the wellbore the injection pressure is decreasing and starts to divert from the trend line. The pressure that can be read at point “A” is called the Leak-Off Pressure (LOP) and is used to calculate the formation fracture gradient.

To make sure the fracture pressure has been reached, the pump is not turned off before point “B” is reached. After point “B” the pressure decrease is plotted versus time instead of pump rate. The rate at which the pressure decreases may tell something about the mud flow from the well into the formation (Bourgoyne et al. 1986).

A leak-off test is quite harmful and may leave the well in a worse condition than it was before the test was carried out. When it is really necessary to know how far it is possible to drill into the next formation the LOT may be used.

Because regular LOT may vary in accuracy, the need for a more precise method led to the development of the extended leak-off test.

4.5.2 Extended Leak-off Test

An extended leak-off test is a regular leak-off test followed by one or more pressure build up cycles. Figure 4.6 shows an idealized pressure response of a XLOT with three pressure cycles. In cycle one the pressure is increased until leak-off and the leak-off pressure is read. To overcome the tensile strength two more cycles are carried out. When the pressure starts to divert from the trend line on the second and third cycle the fracture propagation pressure is read.

From Figure 4.6 it can be seen that the pressures required to inflict a fracture is greater than the pressure needed to reopen it. The second and third cycle gives a better estimate of the minimum stress magnitude than the first cycle and is why the XLOT is preferred to estimate the fracture gradient (Addis et al. 1998).

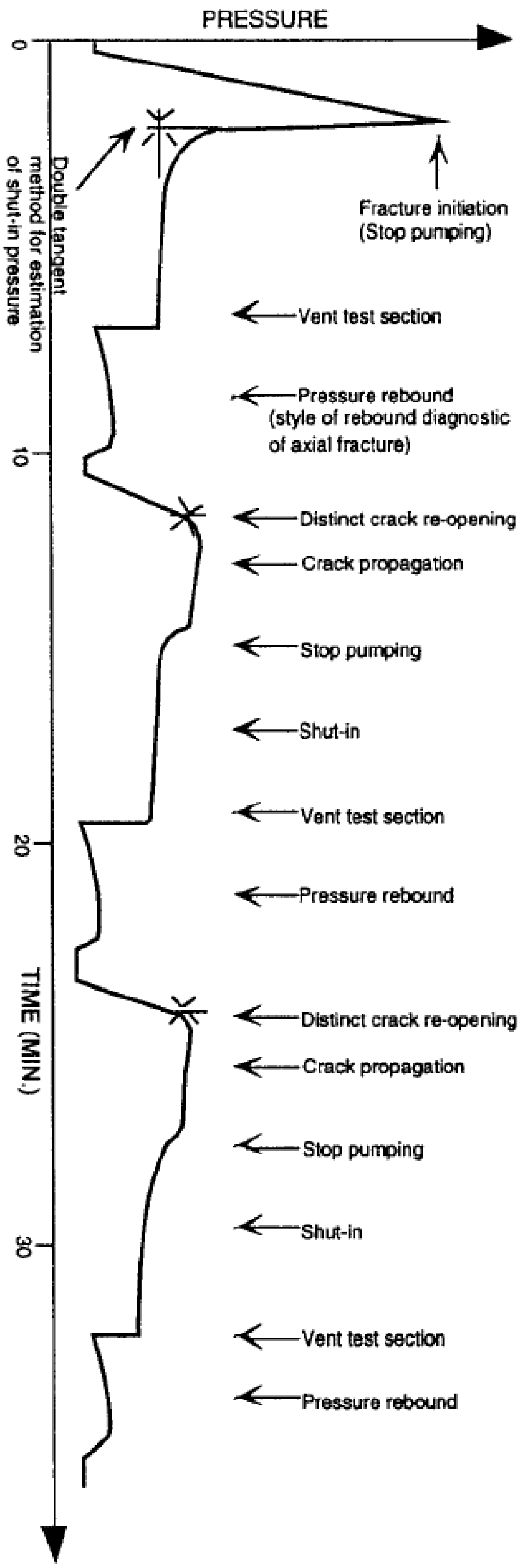


Figure 4.6: Idealized example of an XLOT with three cycles (Addis et al. 1998).

4.5.3 Formation Integrity Test

In a formation integrity test, the aim is not to give the fracture gradient a number. The aim is to confirm that formations below the casing shoe holds acceptable integrity conditions and is able to handle the pressure needed to drill the next section.

The FIT is often used if there is a suspicion that a formation along the well path is weaker than the trend, i.e. the formation strength is not increasing as expected with regards to the depth.

The test is carried out by pressurizing the well towards a predefined value. Preferably a pressure with a magnitude less than the fracture re-opening pressure found during the XLOT to prevent the induced fracture to reopen. From the known density of the drilling fluid and predefined formation integrity pressure, the pressure that needs to be induced at surface can be calculated as seen below in equation 2.

$$p_{FIT} = \rho g D + p_s \rightarrow \rho_e = \frac{p_{FIT}}{gD} \tag{1}$$

$p_{FIT} =$ Predefined maximum pressure
$\rho =$ Density of mud
$g =$ Gravity (9,81 kg/m*s^2)
$D =$ Vertical depth of the well
$p_s =$ Pressure induced at surface
$\rho_e =$ Derived density equivalent

Since the surrounding formation is not exposed to a pressure exceeding its fracture pressure, the FIT is less harmful than the LOT and is preferable with regards to ensuring the integrity of casing shoe and formation.

Short sum up

In short the different pressure integrity tests are used to evaluate the casing shoe strength and the surrounding formation. The LOT and XLOT can be used to indicate the formation strength while the FIT is used to confirm that a target zone holds an acceptable integrity condition.

The XLOT gives a more exact indication of the formation strength than the LOT. When the formation strength is the main objective of a test the XLOT is therefore run.

5 Influence of Casing Shoe Depth on SCP during Production

The production phase may have special drilling requirements to prevent SCP to arise as a result of unfavorable casing shoe setting depth. This chapter will try to emphasize how setting depth should be chosen to suit the production phase.

There are developed some common guidelines that should be followed to ensure well integrity. Well known guides are the Norsok standard D-010 "Well integrity in drilling operations" and the OLF-117 "Recommended Guidelines for Well Integrity"

According to OLF - 117 the setting depth of casing shoes should be chosen with regards to formation strength. The well may then be able to withstand any influx from deeper formations during the lifetime of the well. Also designing and choosing equipment that will work properly under the environmental conditions present in the area minimizes the chance of developing SCP (OLF – 117 2011).

There are also developed "new" drilling methods like Managed Pressure Drilling (MPD), Dual Gradient Drilling (DGD) and drilling with lower circulation rate to reduce the equivalent circulation density. All of these methods may allow drilling further than what would be possible using the conventional drilling method. Using lower circulation rate of mud while drilling may lead to a problem during cementation. The formation may not be able to withstand the necessary pressure required to perform a good cement job.[3]

During drilling the casing shoe is set as deep as possible based on the mud weight and fracture gradient. To set a casing deeper may therefore be impossible without pushing boundaries and reducing safety factors. A solution on how to enable a deeper setting depth may be to add an extra casing string to the well design. This is done by setting one casing shallower than initially planned and increase the mud weight. The increased mud weight makes it possible to drill the next section deeper than initially planned and the additional can be set deeper.

5.1 Cases

In this chapter five generic cases with unfavorable intermediate casing shoe setting depth causing SCP will be presented. After each case a solution to how SCP may be avoided is proposed. Costs related to the different solutions have to be evaluated when deciding which option to choose.

[3] Information acquired through personal communication with Sigbjørn Sangesland 18.05.2012.

5.1.1 Case 1: Leak below production packer

Figure 5.1 shows a typical candidate well for SCP. The 9 5/8 in. cement does not qualify as a primary barrier according the requirements in Norsok D-010. To qualify as a barrier TOC outside the 9 5/8 in. casing should be above the production packer. This defect occurs relatively frequently old wells and is therefore discussed here.

The SCP in annulus "b" and possibly in annulus "c" shown in Figure 5.1 is happening because of two barrier element failures. The first failure is taking place in the 7 in. liner while the second failure is in the 9 5/8 in.

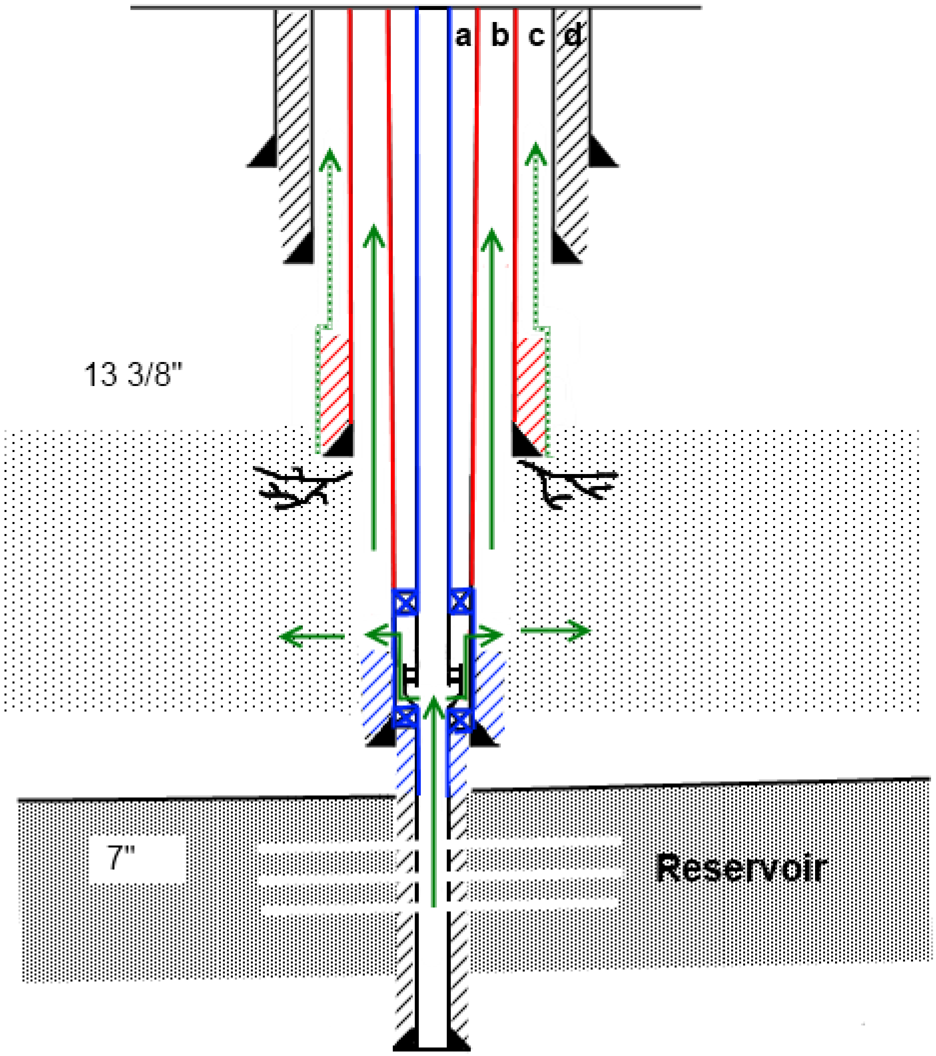


Figure 5.1: Cement outside the 9 5/8 in. casing is set below the production packer. A leak below the production packer may therefor lead to fluid flowing into the formation or SCP in annulus "b" and/or annulus "c". Primary barrier is marked with blue and secondary barrier with red color.

If a leak occurs below the production packer, and the formation outside cannot withstand the pressure, the fluid may flow along the wellbore or into the formation. In some cases all the way to the surface. If fluid is allowed to flow along the 9 5/8 in. wellbore, SCP may build up in annulus “b”. Since annulus “b” is outside the secondary barrier envelope, SCP is very unfavorable here.

A SCP situation may or may not occur in annulus “c” depending on the formation in which the 13 3/8 in. casing shoe is set and the cement quality. This scenario is more thoroughly described in case 3.

Proposed Solution

If the cement had been set above the production packer as shown in Figure 5.2, the problem might have been eliminated assuming the cement provided an impermeable seal. Also if the 13 3/8 in. casing and cement could have been redefined as a barrier, the SCP in annulus “b” would have been inside a barrier envelope and easier to control.

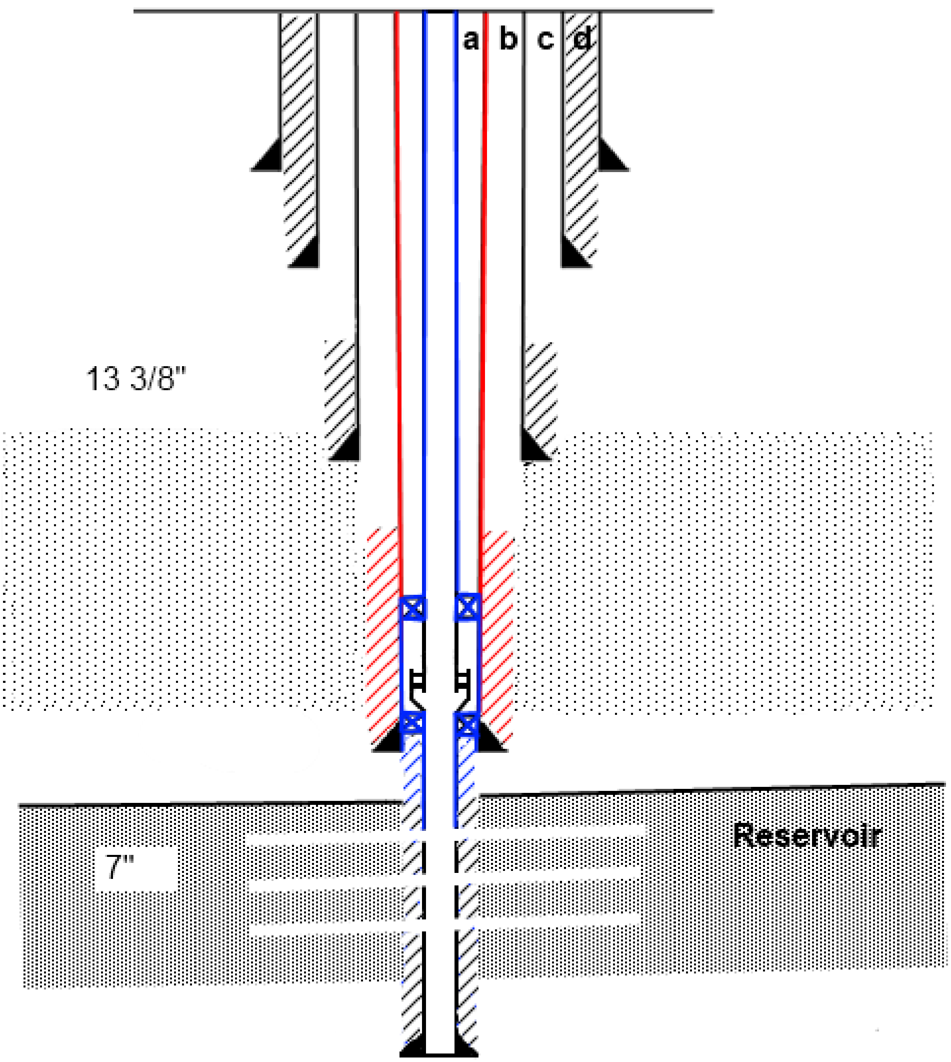


Figure 5.2: Well cemented above production packer according to the Norsok standard D-010. Primary barrier is marked with blue and secondary barrier with red color.

Comparison

It is not without reason the Norsok D-010 has defined that the cement needs to be over the production packer to be valid as a barrier. If the packer not is covered by cement and the 13 3/8 in. casing cannot be redefined as a barrier, the well only has one valid barrier. According the Norsok standard there should always be at least two independent barrier envelopes in a well operation when a risk of uncontrolled outflow from the well to the external environment is present.

5.1.2 Case 2: Casing shoe above unsealed high pressure formation

In Figure 5.3 a high pressure formation has to be drilled through to reach the reservoir. To be able to drill conventionally through the high pressure formation, the 13 3/8 in. casing shoe was set just before entering the formation. The next casing was set at a depth that made it impossible to seal off the high pressure zone by cement. The result was an open hole section in the high pressure formation. Because the pore pressure in the high pressure formation exceeded the annulus fluid pressure, formation fluids were entering the wellbore creating SCP in annulus “b”.

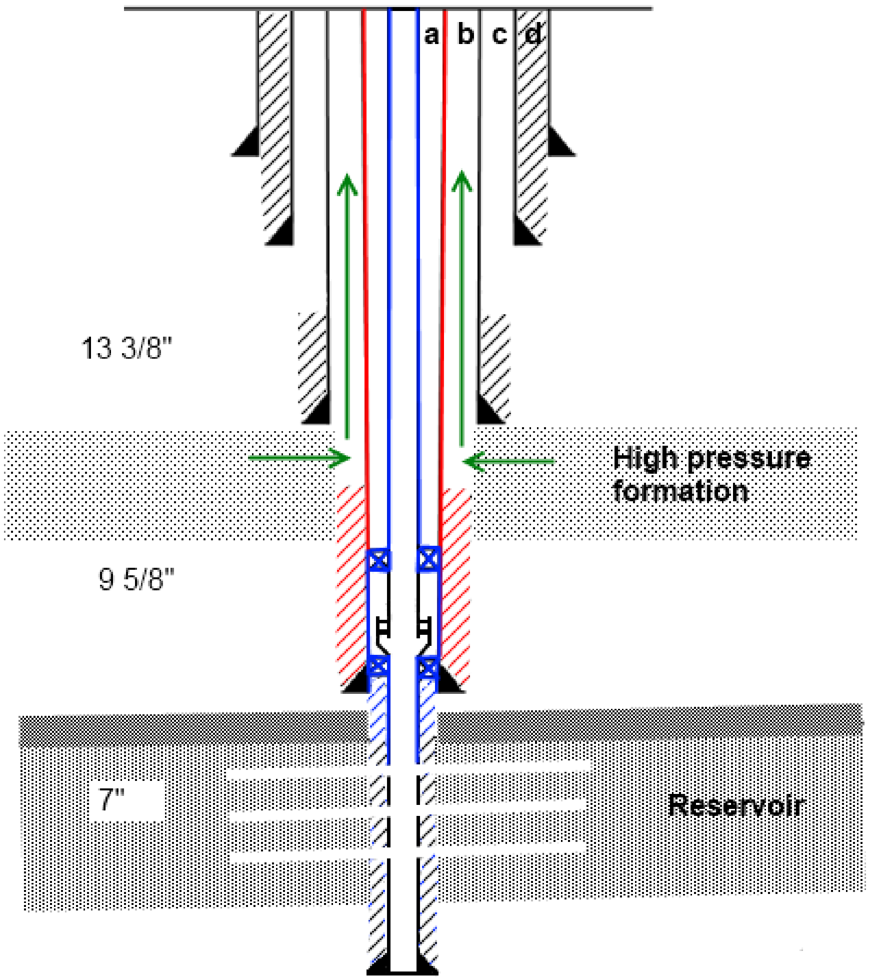


Figure 5.3: Fluid from the high pressure zone enters the well causing pressure build up in annulus "b". Primary barrier is marked with blue and secondary barrier with red color.

Proposed Solution

To solve the problem with SCP arising in annulus "b" because of influx of formation fluids an extra casing may be used as shown in Figure 5.4. The 9 5/8 in. casing is set just below the high pressure formation instead of just above the reservoir. The new setting depth of the 9 5/8 in. casing makes it possible to seal off the high pressure formation. Since the 9 5/8 in. casing is set shallower a 7 in. production casing is set right above the reservoir. The production liner diameter is therefore reduced from 7 in. to 5 1/2 inches.

This solution is in accordance with the recommendations from OLF – 117; "*Formation zones which can give influx and pressure build up in annuli outside the established well barriers is often the most complex and challenging situations to manage and eliminate after SCP has occurred.*" When the zone is properly isolated the drilling can be continued to the initially planned depth, but now with a smaller diameter.

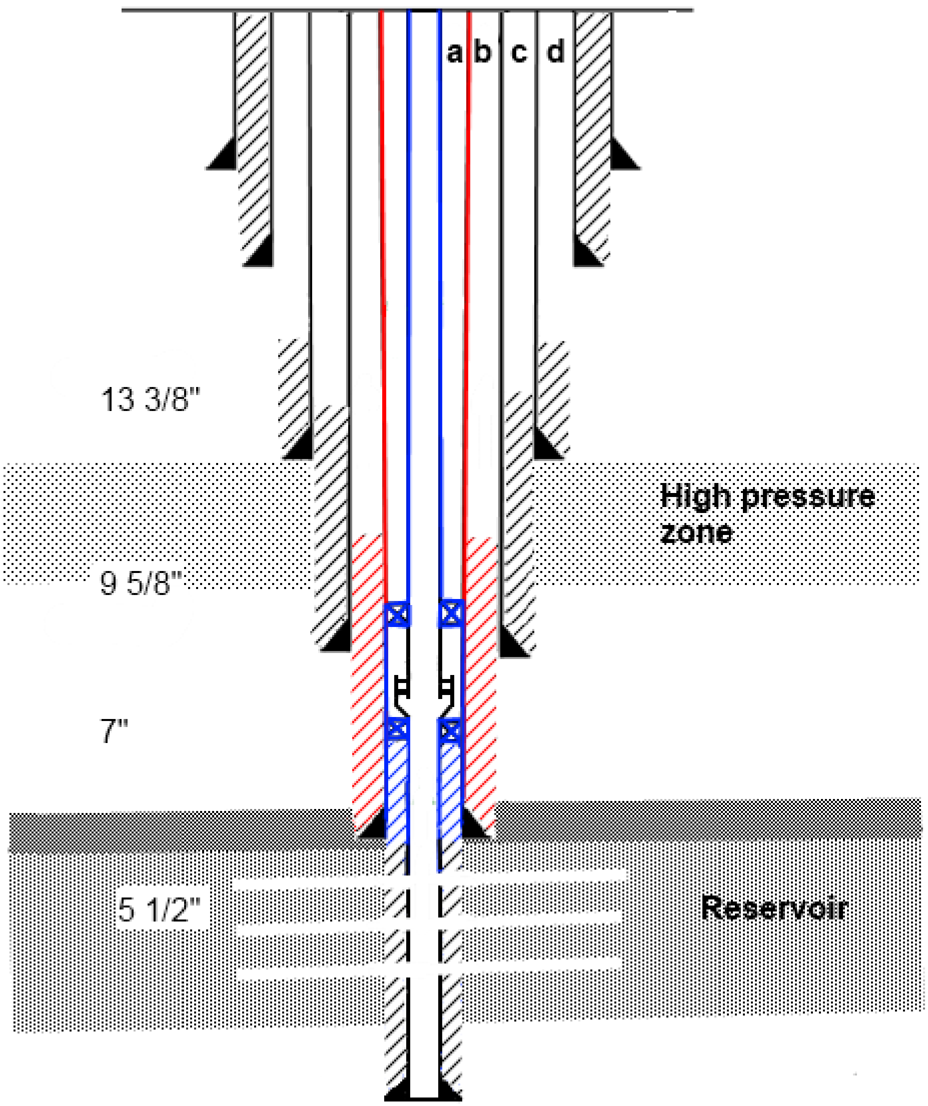


Figure 5.4: The high pressure formation is properly sealed off preventing any inflow to the well. Primary barrier is marked with blue and secondary barrier with red color.

Comparison

It can be seen in Figure 5.3 that it was rather a lack of barriers than barrier failure that caused SCP. In Figure 5.4 it is shown how an extra casing string may be inserted enabling a proper seal off of the formation. It is more likely to get the high pressure formation properly sealed off when the height of the cement column is reduced. If the required seal off height is too large, the weight of the column might exceed the formation strength. In Figure 5.3 the required height was quite large. By inserting an extra casing string the required height is reduced and a successful seal off is more likely.

In the proposal above an extra production casing of 7 in. was inserted leading to a reduction of the production liner diameter from 7 to 5 1/2 inches.

To avoid the reduction in production liner diameter it may have been possible to insert an 11 in. casing between the intermediate and production casing. If the casing strings are designed to withstand high pressure, the wall thickness will be quite large. The insertion of an extra casing string may therefor lead to a tight casing program. It may be harder to perform a good cement job in a tight annulus due to circulation rate.

If possible a different drilling method like dual gradient or MPD may have been used instead of inserting an en additional casing. This may have allowed setting the 13 3/8 in. casing shoe below the high pressure formation and the production liner diameter would stay unchanged. To use a different drilling method the previous set casing shoe must be able to withstand the pressure it may be exposed to in case of a leak.

To save steel the 9 5/8 in. intermediate casing may have been set as a liner as seen in Figure 5.5. A liner can be used instead of a casing string extending all the way to the surface if the previous casing string is designed any SCP that may occur.

If the burst resistance of a casing is increased, so is the wall thickness. A large diameter pipe needs a greater thickness than a small diameter pipe to resist the same amount of pressure. It may therefore be favorable to run the casing all the way to the surface instead of increasing the diameter of the previous casing string.

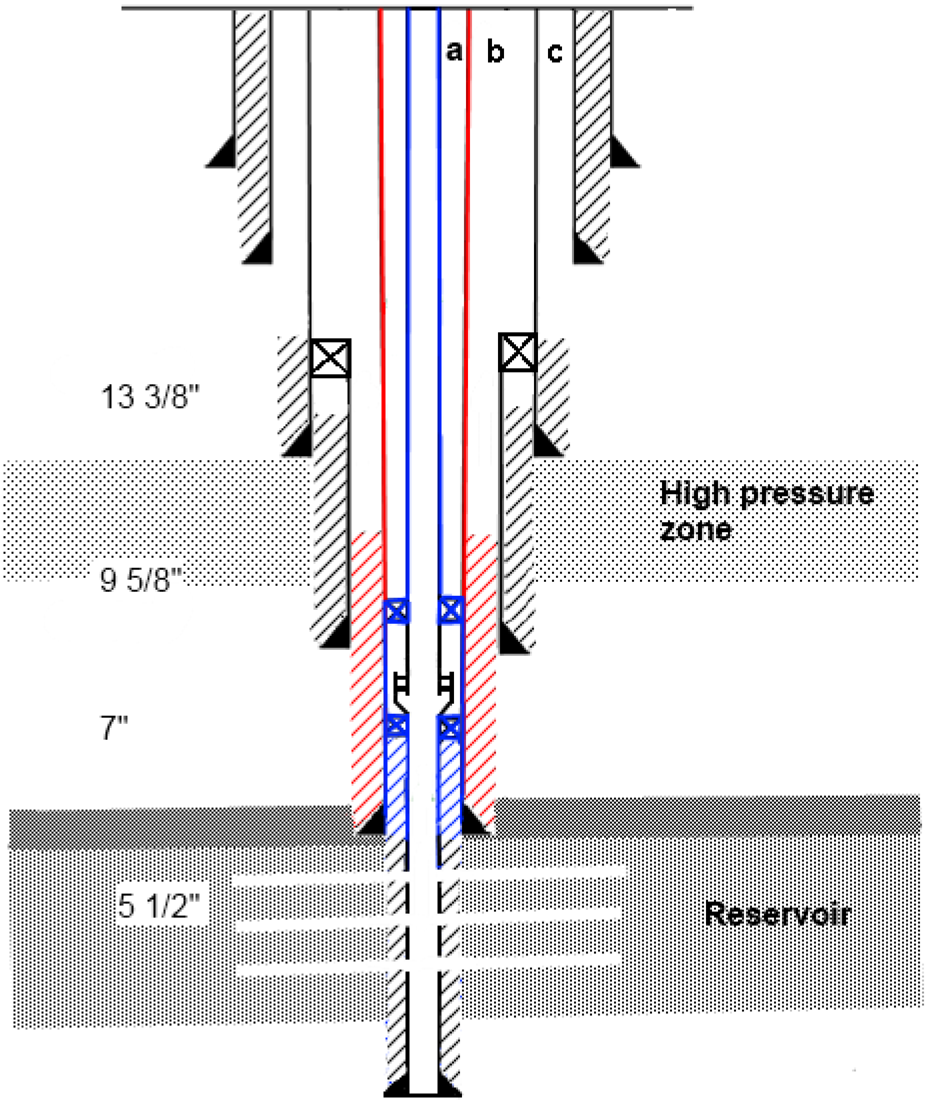


Figure 5.5: The 9 5/8 in. casing is set as a liner instead of a casing going all the way to the surface. Primary barrier is marked with blue and secondary barrier with red color.

5.1.3 Case 3: Casing shoe set in weak formation

In Figure 5.6 a situation where two formations with different formation strength are located close to the setting depth of the 13 3/8 in. casing is shown. The 13 3/8 in. casing is set in the top formation i.e. the weakest formation of the two. During production a leak occurs in the production liner and in the 9 5/8 in. casing below the casing hanger packer. Reservoir fluid is allowed to flow and build up pressure in annulus "b". The weak formation cannot withstand the reservoir pressure and fractures below the 13 3/8 in. casing shoe. Because of a bad formation/cement bond or channels in the cement fluid is allowed to flow into annulus "c" creating SCP here as well.

If the leak occurs in other parts of the well, other sections of the well path may experience the same challenges.

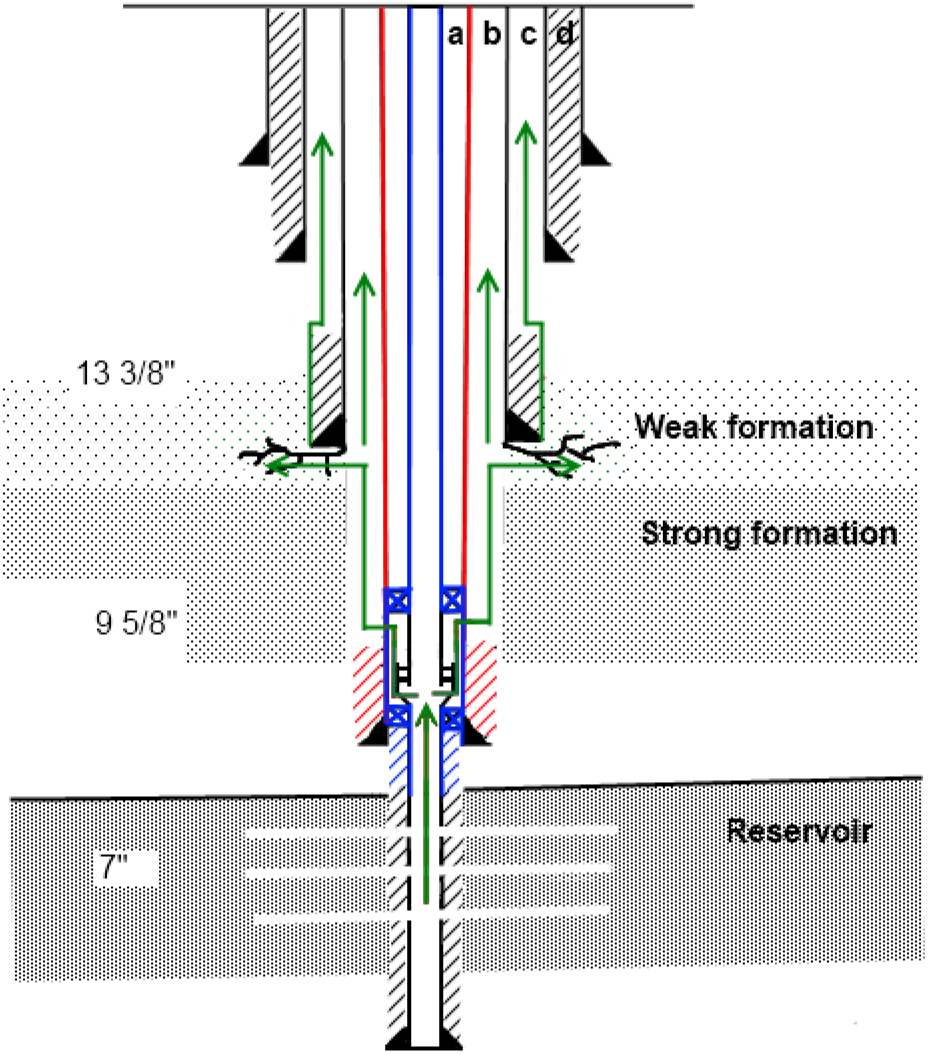


Figure 5.6: 13 3/8 in. casing shoe is set in weak formation. The casing shoe and formation cannot handle the pressure of the leaked fluid. The shoe and surrounding formation cracks and fluid is allowed to enter the formation and/or migrate along the 13 3/8 in. casing into annulus "c". Primary barrier is marked with blue and secondary barrier with red color.

Proposed Solution

If the casing shoe can be set in different formations, OLF recommends setting the shoe in the formation that can withstand reservoir pressure.

Assuming the strong formation could withstand reservoir pressure, the casing shoe should have been set there instead. By utilizing a different drilling method it may be possible to drill far enough so that the casing shoe can be set in the strong formation. An illustration of casing shoe set in the strong formation can be seen in Figure 5.7.

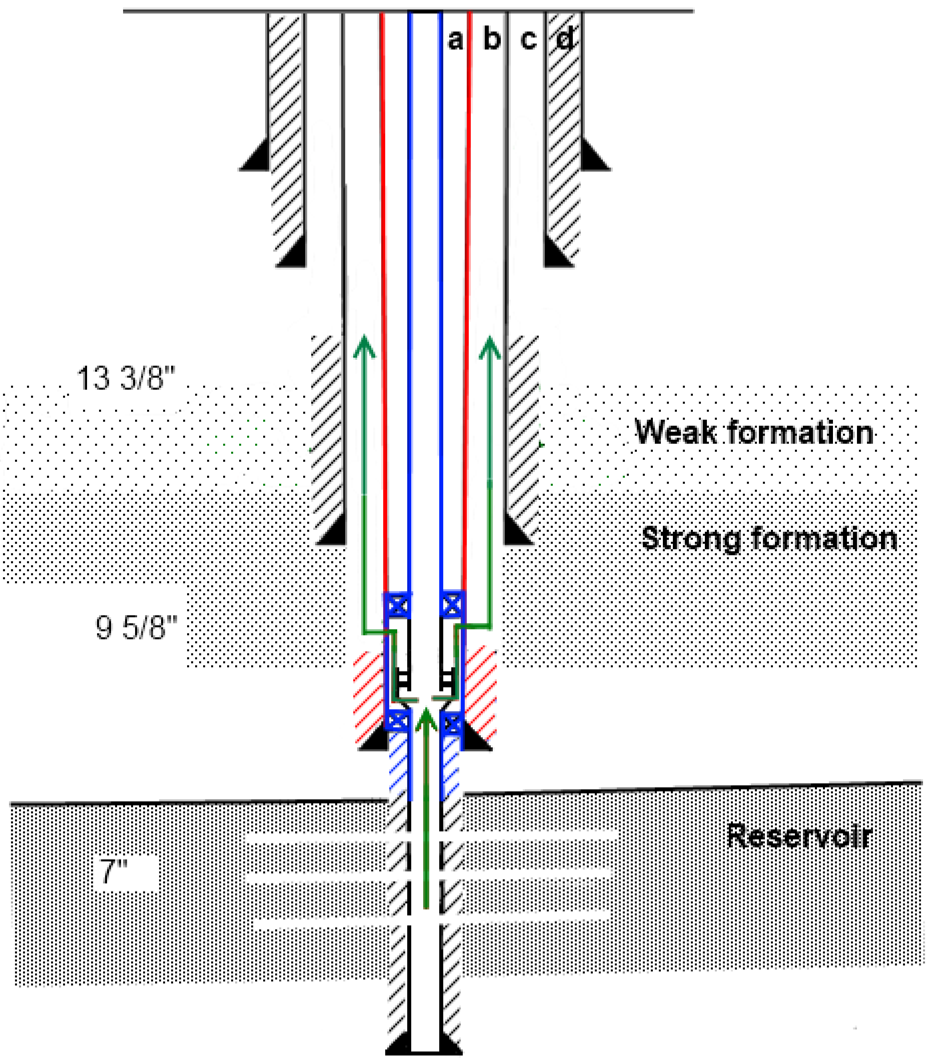


Figure 5.7: Casing shoe set in the strong formation. 13 3/8 in. casing and cement can be redefined as a well barrier hence SCP can be monitored and controlled. Primary barrier is marked with blue and secondary barrier with red color.

If a more advanced drilling method not enables deep enough drilling, an extra casing or liner may be applied. Setting the 13 3/8 in. casing shallower and adding an 11 in. casing may allow the 9 5/8 in. casing to be drilled deeper and set in the strong formation as shown in Figure 5.8.

Setting the shoe in the strong formation makes it possible to redefine the 13 3/8 in. casing and cement to a well barrier if required. The redefinition is possible because the formation in the open hole section between the 9 5/8 in. cement and the 13 3/8 in. casing qualifies as a well barrier element.

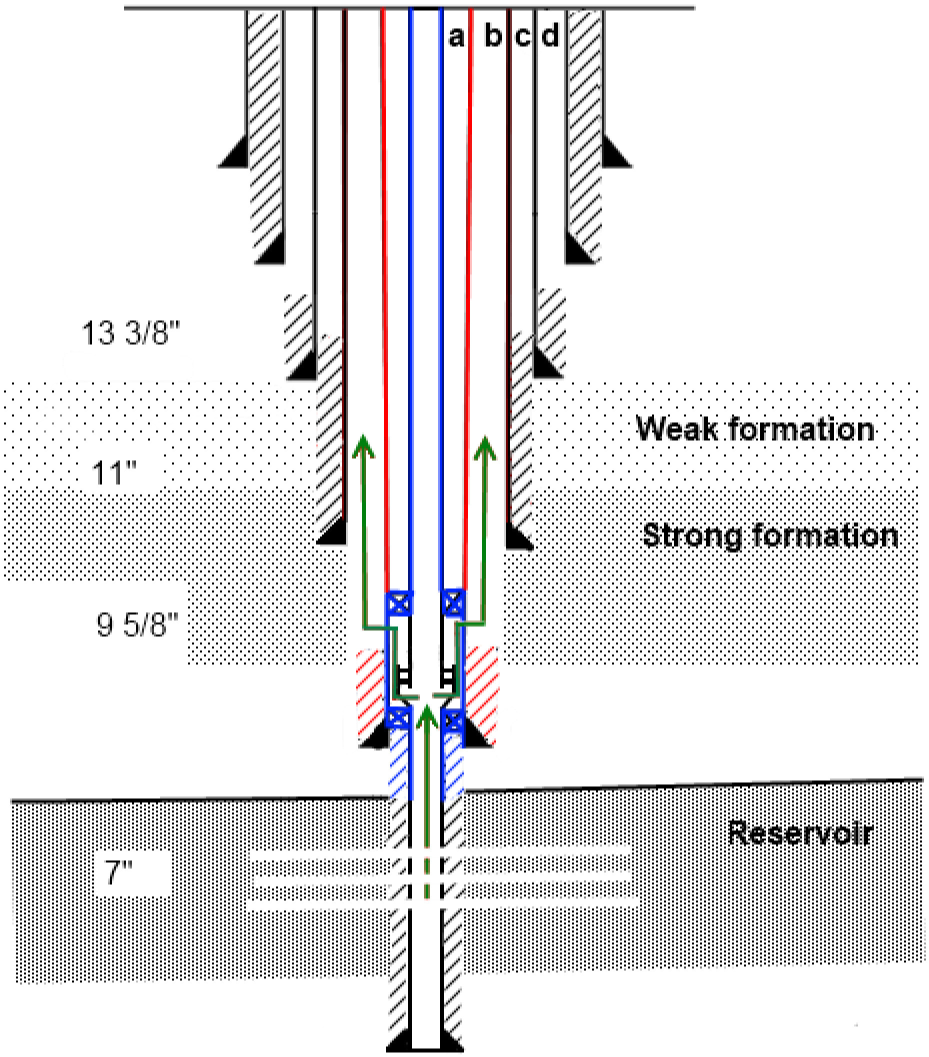


Figure 5.8: An additional 11 in. casing string is used to make it possible to set the 9 5/8 in. casing in a formation that can handle reservoir pressure. Primary barrier is marked with blue and secondary barrier with red color.

Comparison

As mentioned in the discussion in case 2, to insert an extra casing in the casing program may involve challenges related to casing thickness and cementing. An option if whether further drilling or inserting the 11 in. casing is possible is to set a 9 5/8 in. casing at the planned 11 in. casing depth. A 7 in. production casing may be set above the reservoir and reduce the production liner diameter to 5 1/2.

5.1.4 Case 4: Leak below Production Casing Shoe

If a leak occurs below the production casing shoe it will not be restrained by the secondary barrier. This may be an extra unfortunate situation and should by all means be avoided. Figure 5.9 shows two possible origins of SCP. One leak has origin directly from the reservoir along the 7 in casing. The other leak has origin in production liner and cement failure. The formation in which the 9 5/8 in. casing shoe is set in cannot withstand reservoir pressure. Reservoir fluids are therefore allowed to flow into the formation and along the 9 5/8 in. cement into annulus “b”.

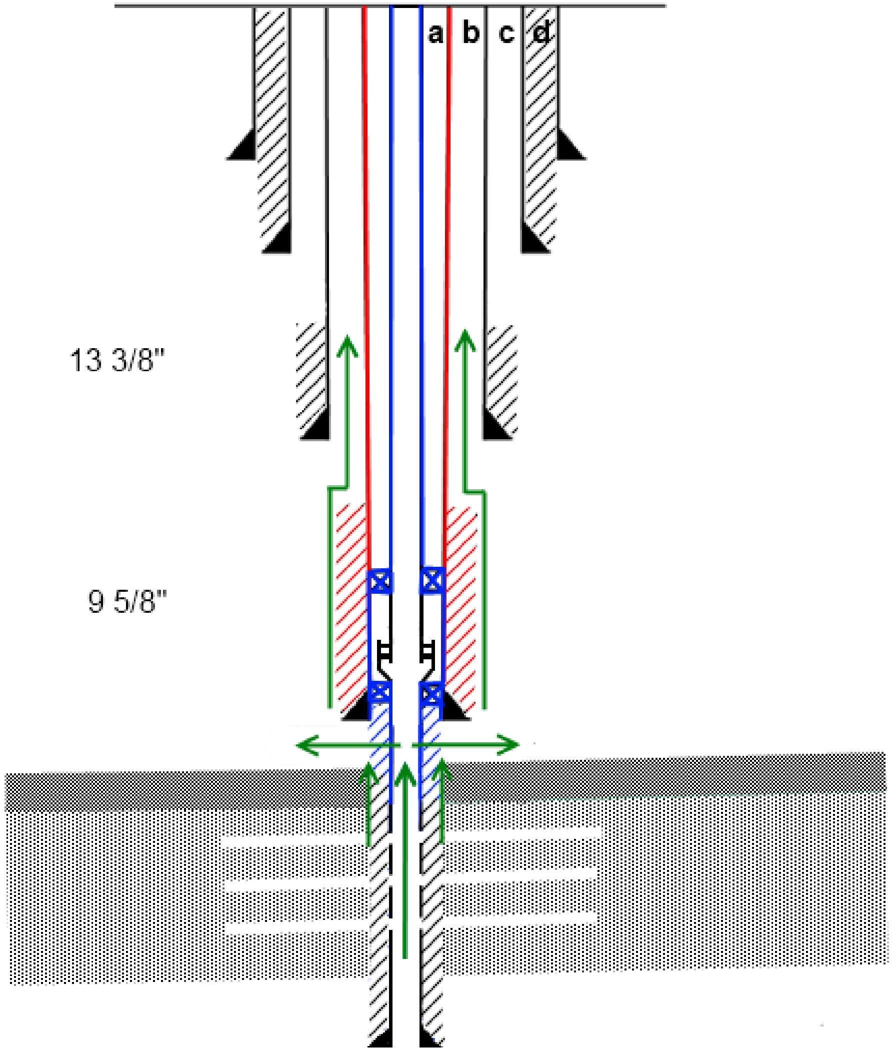


Figure 5.9: Leak below liner hanger packer migrating into annulus “a”, “b” and surrounding formation. Primary barrier is marked with blue and secondary barrier with red color.

Proposed Solution

If it is found out that the formation strength at the chosen setting depth for the 9 5/8 in. casing not is sufficient to withstand reservoir pressure, the casing shoe needs to be set deeper (since formation strength usually is increasing with depth). If no part of the formation can take the pressure, the casing shoe may be set in the cap rock. The original 9

5/8 in. casing can be extended by using optional drilling methods or an additional casing string can be utilized.

In Figure 5.10 it is shown how the 9 5/8 in. production casing is set in the cap rock to prevent fluids from escaping and crating SCP in annulus “b”.

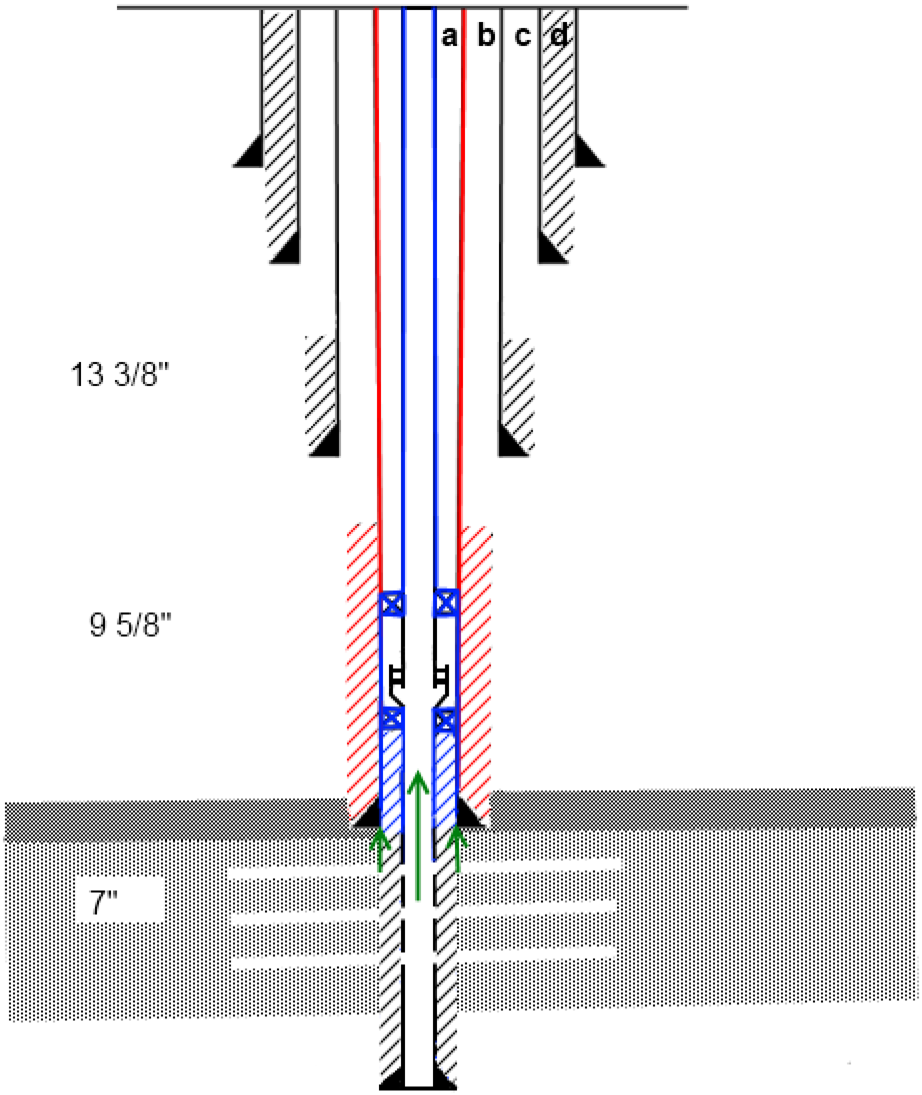


Figure 5.10: The 9 5/8 in. Casing is set deeper to extend the secondary barrier so that it protects leaks from below casing hanger packer. Primary barrier is marked with blue and secondary barrier with red color.

Adding an extra casing string after the 9 5/8 in. casing may affect the liner diameter. Figure 5.11 shows how the liner diameter is reduced from 7 in. to 5 1/2 in. because a 7 in. production casing is inserted. Inserting an additional casing earlier in the drilling process may be an option that allows the production casing to be set deeper. It may also not affect the production liner diameter.

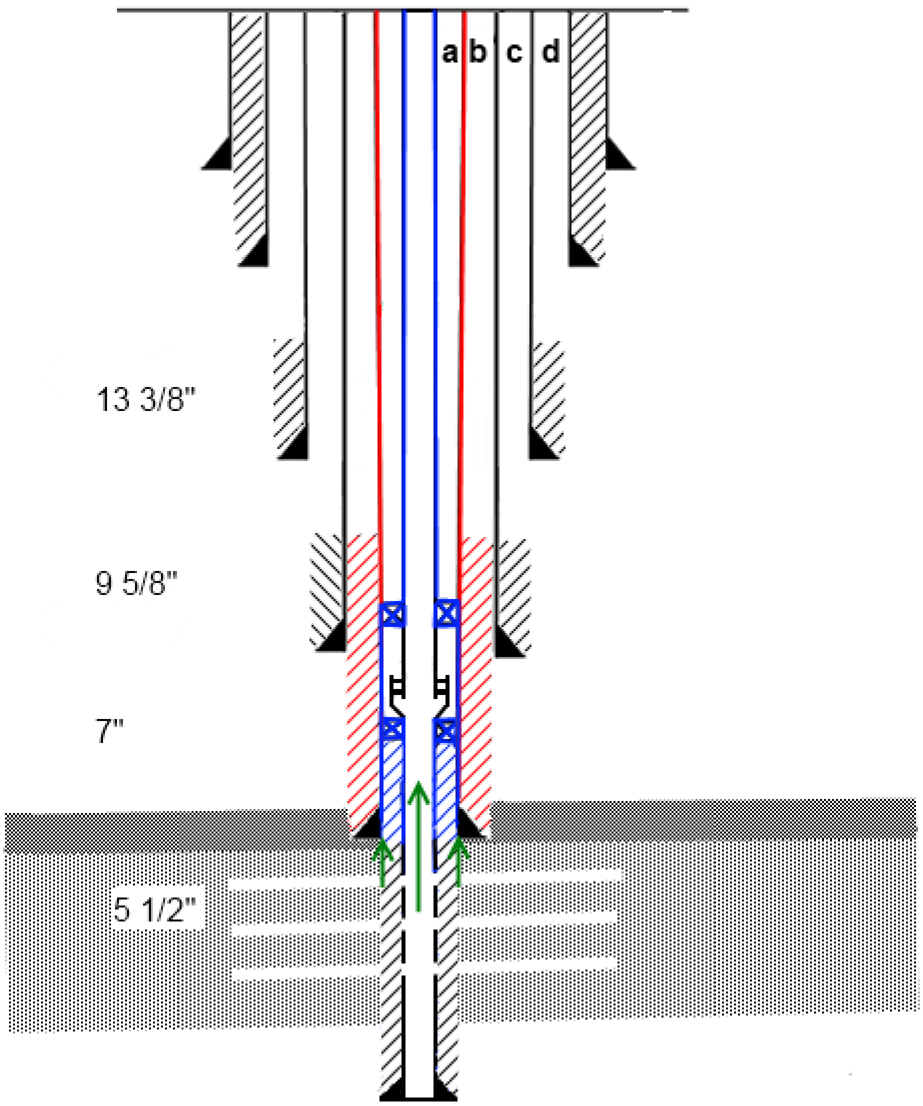


Figure 5.11: A 7 in. production casing is added after the 9 5/8 in. to extend the secondary barrier so that it can prevent leaks from under the liner hanger packer to travel into annulus "b" and the surrounding formation. Primary barrier is marked with blue and secondary barrier with red color.

Comparison

In the well planning phase the different formation strengths are supposed to be tested. If it is found out that the in the formation above the reservoir cannot withstand reservoir pressure, a casing planned to be set there should be reconsidered.

If the leak path is directly from the reservoir along the 7 in. cement it may be hard to remove by redesigning the well. To remove this leak by setting the production casing in the caprock, the casing shoe has to be completely tight.

6 Discussion

Much work has been dedicated to the study of SCP such as Bourgoyne et al. 1999 and Wojtanowicz 2001. When it comes to explaining how SCP arises, most research has its main focus on equipment failure, cement quality and cementing performance. Very little is done on the relation between casing shoe setting depth and SCP.

The common practice today is often to drill a well with consideration to only situations that may arise during drilling. In this study it has been tried to reveal whether the well would have been drilled differently if the production phase had been taken into consideration during the design phase.

Some factors contributing to the decision of casing shoe setting depth today are:

- Pore pressure
- Fracture gradient
- Protection of freshwater aquifers
- Lost circulations zones
- Salt beds and low pressure zones that may cause stuck pipe
- Kick criteria

These factors are important and should be considered to ensure a safe drilling operation. Since the well has more than one stage during its lifetime, factors that can contribute to improve the safety should also be implemented during well planning and design. Some important factors that are advantageous during the production phase are:

- Possible to redefine barriers
- Set shoe in strong formation so that it can withstand situations with high pressure
- Avoid open hole sections in high pressure and high permeable formation

Cementing

Many SCP situations that occur because of fluid migration between casing layers is a result of bad conversion between TOC and the previous casing shoe setting depth. If the cement column had been higher, or the casing shoe had been set deeper, many SCP situations may have been avoided.

If the well had been completed with completely overlapping between all cement columns and casing strings, the problem with SCP related to casing shoe setting depth might have been avoided. Figure 6.1 shows a well design where inflow into annulus from surrounding formations is prevented by overlapping between cement and previous casing strings. This assumes that the cement sheet is flawless hence no channels, good cement-formation/casing bond, etc. As previously discussed the chance of a perfect cement seal is very small.

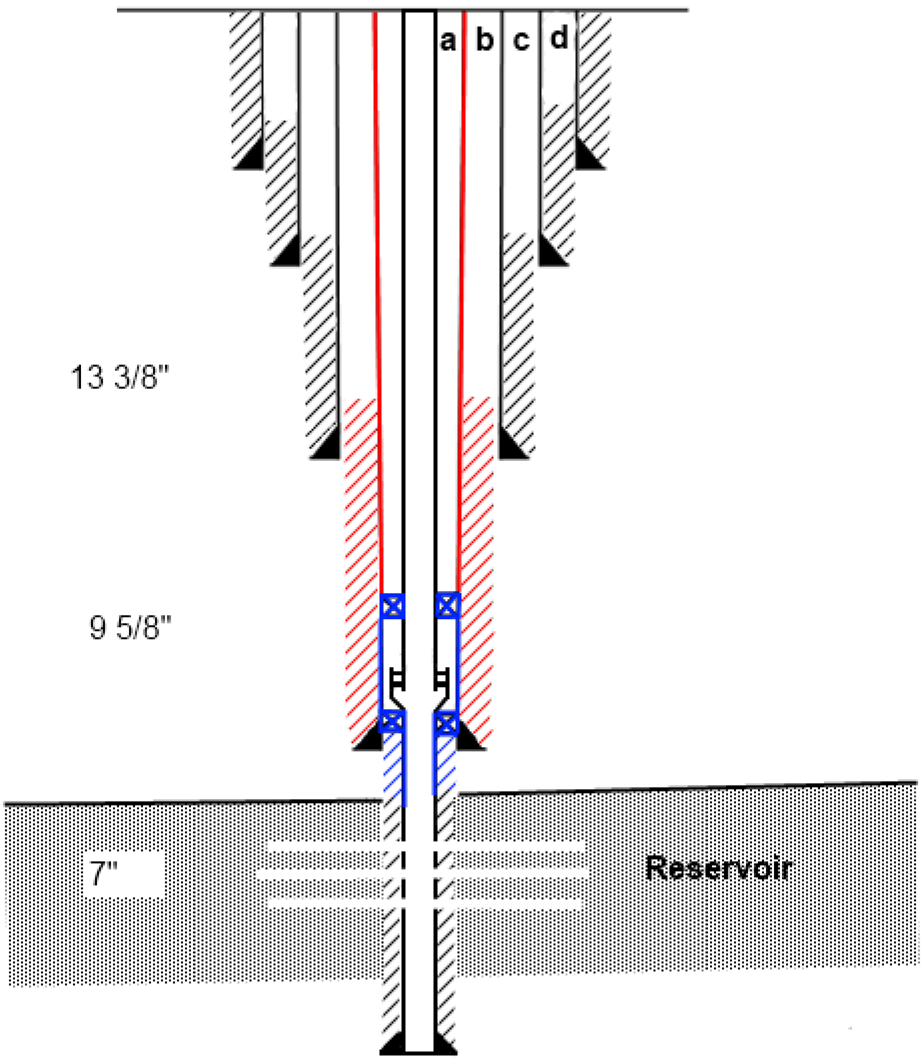


Figure 6.1: Well design preventing inflow from surrounding formation into annulus if the cement is perfect without channels and the cement-formation/casing bond is good etc. Primary barrier is marked with blue and secondary barrier with red color.

It is not common practice to have overlapping sections between cement and casing strings in all parts of the well. This may be due to:

- Cement expenses and complications related to obtaining a good cement sheet when cementing over large intervals.
- Much easier to do a sidetrack in an open hole than in a cemented section.
- Sometimes it may be better that excessive pressure has the opportunity to flow into the formation rather than building up inside the annulus threatening to break casing strings and in worst case the wellhead causing a blowout.

In order to qualify as a well barrier the cement has to fulfill the requirements listed in Table B. 8 in Appendix B.

There may be several different reasons to why the cement is not satisfying the criterion. It may be.

- The required height of the cement column creates too large pressure on the formation surrounding the casing shoe
- Annulus may be too tight, not possible to squeeze cement into the small space
- Cement may break down the formation

A solution on how to get the cement column high enough is to use squeeze cementing. The bottom part is cemented first, then the casing can be perforated at TOC and the next section is cemented. One of the disadvantages related to squeeze cementing is that the perforated casing creates a possible leak path.

6.1 General Discussion

In this thesis there are basically two types of solutions proposed which can be used to prevent SCP from arising because of unfavorable casing shoe setting depth;

- Additional casing/liner
- Drill deeper using optional drilling methods like MPD, dual gradient drilling, etc.

Which method to use has to be evaluated in each individual case. If further drilling with the same mud weight is impossible or too dangerous, an additional casing or liner may be applied. Whether to use a liner or casing extending all the way to the surface depends on the pressure resistance in the previous set casing, additional risks, tools and complexities compared to capital savings.

Inserting an additional casing between the casing strings in the initially planned casing program may in some cases not be very favorable. The extra casing may lead to a too tight casing program resulting in difficulties during cementing. If the annulus is very narrow the required displacement rate may be larger than what is allowed by casing shoe and formation.

To avoid a narrow casing program all planned casing strings may be shifted upwards i.e. the diameter used for the production liner ex. 7 in. is used on the production casing, and the production liner is assigned a smaller diameter ex. 5 1/2 inches.

Another option is, if possible, to design the surface casing with a larger diameter so that all following casing strings may have a larger diameter. This has to be planned from the very beginning. Drilling larger holes is both more expensive and requires more engine power. It is therefore desirable to drill with the smallest possible diameter.

If the problem can be solved by using an optional drilling method, this may be advantageous. Extra costs related to the additional casing are saved and the production liner diameter may stay unchanged.

SCP is often a result of bad conversion between casing shoe setting depth and TOC. This means that eliminating the deficiency in one of them may remove SCP.

Deficiency for casing shoe setting depth may include, but is not limited to:

- Casing is not set deep enough
- Casing is not designed to withstand the pressure it may be exposed to
- Casing may be set in a formation that cannot withstand high pressure

Cement deficiency includes, but is not limited to:

- Cement column not is high enough according to the Norsok standard
- Cement is not sealing high pressure zones or weak formations
- Cement failures mentioned in chapter 2.2.2

7 Conclusion

There may be many causes of sustained casing pressure. Through the well integrity survey performed by the Petroleum Safety Authorities, the most common causes for SCP are related to:

- Well barrier failures in tubing
- Failures in annulus safety valve
- Deficiency in cement and casing

When SCP has arisen it may be hard to get rid of. It is therefore more desirable to prevent it from arising by performing the drilling and casing setting after a thoroughly planned well design.

How to best prevent SCP from arising is to:

- Perform thorough investigation of the underground
- Know where hazardous formations are located
- Plan ahead and know where it is advantageous to set the casing and why it is advantageous
- Know the conversion between TOC and casing shoe setting depth
- Larger surface casing to allow insertion of an additional casing string without creating a tight casing program or affecting the production liner and cement process.

The best way of eliminating influx of formation fluid from formations along the wellbore is to identify them in the initial well design planning and when cementing, make sure the annulus is properly cemented.

Further Work

This has been a generic study with generic cases where SCP was a result of “wrong” casing shoe depth. In the future information from real wells that may be suffering of SCP because of non-ideal casing shoe setting depth should be to gather and evaluated.

There is also a need to perform an economic study to make an estimate on how much the extra cost would be for the prevention of SCP.

In this thesis only the production phase has been compared with the drilling phase to see if the “ideal production well design” differed from the “ideal drilling well design”. What is not taken into consideration is the phase after the well is plugged and abandoned (P&A). It should be investigated whether the casing shoe setting depth has any influence on P&A operations. To be able to create the optimal well design the whole life cycle of the well should be considered.

Abbreviations

DGD	Dual Gradient Drilling
FIT	Formation Integrity Test
LOP	Leak off Pressure
LOT	Leak off Test
MMS	Mineral Management Service
MPD	Managed Pressure Drilling
NCF	Norwegian Continental Shelf
Norsok	Norsk Sokkels Konkurranseposisjon
OLF	Norwegian Oil Industry Association (Oljeindustriens Landsforening)
P&A	Plug and Abandon
PSA	Petroleum Safety Authority Norway
SCP	Sustained Casing Pressure
s.g	Specific Gravity
TOC	Top of Cement
WBE	Well Barrier Element
WIF	Well Integrity Forum
WBS	Well Barrier Schematic
XLOT	Extended Leak off Test

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Appendix

Appendix A

Categorization System

To promote a common understanding of the integrity of a well the well integrity forum (WIF) designed a categorization system to classify wells based on their integrity status. A common system is beneficial for both operators who can categorize and rank wells during operations and the PSA who can summarize well integrity across the NCS. The well categorization system covers all wells in operation. (OLF – 117 2011)

During the development it was emphasized to make the system as simple as possible. Based on the double barrier policy system outlined in the regulations and the Norsok D-010 Standard, WIF proposed the 4-cathegory traffic-light system Figure A. 1. It was made up of four colours; green, yellow, orange and red. Green and yellow represents acceptable wells while orange and red are non-compliant wells with integrity problems. (OLF – 117 2011)

Category	Principle
Red	One barrier failure and the other is degraded/not verified, or leak to surface
Orange	One barrier failure and the other is intact, or a single failure may lead to leak to surface
Yellow	One barrier degraded, the other is intact
Green	Healthy well - no or minor issue

Figure A. 1: Barrier Category. (OLF – 117 2011)

Depending on age, complexity, presence of abnormalities and non-conformances different information is required to categorize the well.

To perform a categorization of wells different information is required.

OLF has developed a list of information required to evaluate and categorize a well. The list can include, but is not limited to:

- *Information about well type and well service*
- *Well barrier schematic*
- *Well construction details, including measured and/or predicted formation strength*

- *Design pressures, test pressures and pressure limits*
- *Operational limits*
- *Flowing and shut in pressures & temperatures*
- *Fluid type in tubing and annuli*
- *Annulus pressure and pressure trends*
- *Findings from well interventions and preventive maintenance tests*
- *Known deviations, abnormalities or non-conformances*

If abnormalities and/or conformances are present even further information is required to categorize the well. These can be found in OLF-117.

Green
The well integrity status fulfils standards and has two barriers as is required according to the two-barrier principle. (OLF – 117 2011)

Yellow
The well integrity status fulfils standards and has two barriers as is required according to the two-barrier principle. The well has obtained the yellow colour due to presence of one or more integrity anomalies. Operations can be kept up. (OLF – 117 2011)

Orange
The well does not satisfy standards and the integrity problem is of such dimension that I cannot be neglected. The integrity problem is usually further investigated and the risk associated with the defect of the well is evaluated. For orange wells the failure usually lies within the primary barrier. (OLF – 117 2011)

Red
The well does not satisfy standards and the integrity problem is of such dimension that I cannot be neglected. The integrity problem is usually further investigated and the risk associated with the defect of the well is evaluated. In addition to failure of the primary barrier, red wells suffer from failure or degradation of the second barrier as well. (OLF – 117 2011)

Appendix B

This appendix contains the acceptance criterion tables for the different well barrier elements defined by Norsok.

Table B. 1 explains what the different features in the table means and can be used when reading the following acceptance tables.

Table B. 1: Methodology for the following tables is described.

Features	Acceptance criteria	References
A. Description	*This describes the WBE in words.*	
B. Function	*This describes the main function of the WBE.*	
C. Design (capacity, rating, and function), construction and selection	*For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe* • *design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used,* • *construction requirements for how to actually construct the WBE or its sub-components, and will in most cases only consist of references to normative standards.* *For WBEs that are already manufactured, the focus should be on selection parameters for choosing the right equipment and how this is assembled in the field.*	*Name of specific references*
D. Initial test and verification	*This describes the methods for verifying that the WBE is ready for use after installation in/on the well and before it can be put into use or is accepted as part of well barrier system.*	
E. Use	*This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities and operations.*	
F. Monitoring (Regular surveillance, testing and verification)	*This describes the methods for verifying that the WBE continues to be intact and fulfils it design/selection criteria during use.*	
G. Failure modes	*This describes conditions that will impair (weaken or damage) the function of the WBE, which may lead to implementing corrective action or stopping the activity/operation.*	

Acceptance table for the casing string barrier

Table B. 2: Acceptance table for casing string. (NORSOK standard D-010 2004, Table 2)

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide a physical hindrance to uncontrolled flow of formation fluid or injected fluid between the bore and the back-side of the casing.	
C. Design construction selection	1. Casing-/liner strings, including connections shall be designed to withstand all pressures and loads that can be expected during the lifetime of the well including design factors. 2. Minimum acceptable design factors shall be defined for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. Dimensioning load cases with regards to burst, collapse and tension/compression shall be defined and documented. 4. Casing design can be based on deterministic, probabilistic or other acceptable models.	ISO 11960 API Bull 5C3 API Bull 5C2
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum anticipated differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities.	
E. Use	1. Casing/liner should be stored and handled to prevent damage to pipe body and connections prior to installation.	ISO 10405 API Bull 5C2
F. Monitoring	1. The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 2. If wear conditions exceed the assumptions from the casing-/liner design, indirect or direct wear assessment should be applied (e.g. collection of metal shavings by use of ditch magnets and wear logs).	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking casing/liner.	

Acceptance table for wellhead

Table B. 3: Acceptance table for wellhead. (NORSOK standard D-010 2004, Table 5)

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead body with annulus access ports and valves, seals and casing/tubing hangers with seal assemblies.	
B. Function	Its function is to provide mechanical support for the suspending casing and tubing strings and for hook-up of risers or BOP or production tree and to prevent flow from the bore and annuli to formation or the environment.	
C. Design construction selection	1. The WP for each section of the wellhead shall exceed the maximum anticipated well shut in pressure the section can become exposed to plus a defined safety factor. 2. For dry wellheads, there shall be access ports to all annuli to facilitate monitoring of annuli pressures and injection/bleed-off of fluids. 3. For subsea wellheads, there shall be access to the casing by tubing annulus to facilitate monitoring of annulus pressure and injection /bleed-off of fluids. 4. Wellheads that will be used as a flow conduit for continuous or intermittent production from or injection into annulus/annuli, shall be designed and qualified for such functions without impairing the well integrity function of the wellhead. For gas lift applications, gas expansion and the resulting temperature should be addressed.	ISO 10423
D. Initial test and verification	1. The wellhead body (or bodies and seals), annulus ports with valves and the casing or tubing seal assemblies shall be leak tested to maximum expected shut in pressure for the specific hole section or operation.	
E. Use	1. A wear bushing should be installed in the wellhead whenever movement of tools/work-strings can inflict damage to seal areas.	
F. Monitoring	1. Annuli wing valves shall be pressure and function tested frequently. 2. The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 3. Movements in the wellhead during work over (shut-in/start-up) should be observed and compared to design values.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking seals or valves.	

Acceptance table for the production packer well barrier

Table B. 4: Acceptance table for production packer. (NORSOK standard D-010 2004, Table 7)

Features	Acceptance criteria	See
A. Description	This is element consists of a body with an anchoring mechanism to the casing/liner, and an annular sealing element which is to be activated.	
B. Function	Its purpose is to provide 1. A seal between the completion string and the casing/liner, to prevent communication from the formation into the A-annulus above the production packer. 2. Prevent flow from the inside of the body element located above the packer element into the A-annulus as part of the completion string.	
C. Design, construction and selection	1. It shall as a minimum be tested to V1 class as per ISO 14310. 2. It shall be permanently set (meaning that it shall not release by up or downward forces), with ability to sustain all known loads. 3. It might be retrievable by mechanical intervention, such features shall not be possible to accidentally activate. 4. The packer (body and seal element) shall withstand MEDP, which should be based on the highest of • pressure testing of tubing hanger seals, • reservoir-, formation fracture- or injection pressures less hydrostatic pressure of fluid in annulus above the packer, • shut-in tubing pressure plus hydrostatic pressure of fluid in annulus above the packer less reservoir pressure, • collapse pressure as a function of minimum tubing pressure (plugged perforations or low test separator pressure) at the same time as a high operating annulus (maximum allowable) pressure is present. 5. It shall be qualification tested in accordance with recognized standards, which shall be conducted in unsupported, non cemented, standard casing.	ISO 14310
D. Initial test and verification	1. It shall by preference be leak tested to the maximum expected differential pressure in the direction of flow. 2. Alternatively, it shall be inflow tested or leak tested in the opposite direction to the maximum expected differential pressure, providing that ability to seal both directions can be documented.	
E. Use	1. Running of intervention tools shall not impair its ability to seal nor inadvertedly cause it to be released.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal.	

Acceptance table for surface controlled sub-surface safety valve (SCSSV)

Table B. 5: Acceptance table for surface controlled sub-surface safety valve. (NORSOK standard D-010 2004, Table 8)

Features	Acceptance criteria	See
A. Description	This element consists of a tubular body with a close/open mechanism that seals off the tubing bore.	
B. Function	Its purpose is to prevent flow of hydrocarbons or fluid up the tubing.	
C. Design, construction and selection	1. It shall be positioned minimum 50 m below seabed. 2. The setting depth shall be dictated by the pressure and temperature conditions in the well with regards to forming of hydrates and deposition of wax and scale. 3. It shall be • surface controlled, • automatically operated, • hydraulically operated, • fail-safe closed, 4. It should be placed below the well kick-off point in order to provide well shut-in capabilities below a potential collision point. 5. The fail-safe closing function (maximum setting depth) should be calculated based on the highest density of fluids in the annulus.	API RP14B
D. Initial test and verification	1. It shall be tested with both low and high differential pressure in the direction of flow. The low pressure test shall be maximum 7 MPa.	
E. Use	1. When exposed to high velocities or abrasive fluid, increased testing frequency shall be considered.	
F. Monitoring	1. The valve shall be leak tested at specified regular intervals as follows: • test duration shall be 30 min, • monthly, until three consecutive qualified tests have been performed, thereafter - • every three months, until three consecutive qualified tests have been performed, thereafter - • every six months. 2. Acceptance of downhole safety valve tests shall meet API RP 14B requirements being • 0,42 Sm^3/min (25,5 Sm^3/hr) (900 scf/hr) for gas, • 0,4 l/min (6,3 gal/hr) for liquid. 3. If the leak rate cannot be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed. 4. If the leakrate exceeds the accept criteria, the test can be attempted three times to verify the valve status. If the accept criteria is still not meet, further investigation and remedial action shall be undertaken, consider involving the drilling/well operations department.	API RP 14B ISO 10417
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Failure to pass the regular test intervals and maximum allowable leak rate.	

Acceptance table for the tubing hanger

Table B. 6: Acceptance table for tubing hanger. (NORSOK standard D-010 2004, Table 10)

Features	Acceptance criteria	See
A. Description	This element is consists of body, seals and a bore which may have a tubing hanger plug profile.	
B. Function	Its function is to • support the weight of the tubing, • prevent flow from the bore and to the annulus, • provide a seal in annulus space between the itself and the wellhead, • provide a stab-in connection point for bore communication with the production tree. • provide a profile to receive a BPV or plug to be used for nippling down the BOP and nippling up the production tree.	
C. Design, construction and selection	1. Shall be designed and fabricated according to ISO 13533 2. When used in conjunction with annulus injection (gas lift, cutting injection, etc.) any low temperature cycling effects need to be taken into consideration.	ISO 13533
D. Initial test and verification	1. The primary seal shall be tested in the flow direction. 2. The hanger seal can be tested against the flow direction. 3. If only single seals are used in the tubing hanger, annulus is to be tested. In the case of double seal, an in-between seal test might be performed.	
E. Use	1. None.	
F. Monitoring	1. Continuous monitoring of annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak past seals.	

Acceptance table for well head/annulus access valve

Table B. 7: Acceptance table for well head/annulus access valve. (NORSOK standard D-010 2004, Table 12)

Features	Acceptance criteria	See
A. Description	This is element consists of the wellhead housing and an isolation valve.	
B. Function	Its function is to provide ability to monitor pressure and flow to the A-annulus below the tubing hanger.	
C. Design, construction and selection	1. The housing shall have a material grade and specification compatible with the materials of which it is attached to. 2. The housing and valve(s) shall be fire resistant. 3. The valve shall be gas tight. 4. The access point and valve shall have a pressure rating equal to or higher than the wellhead/production tree system. 5. When used in conjunction with annulus injection (gas lift, cuttings injection, etc.) any low temperature cycling effects need to be taken into consideration.	
D. Initial test and verification	The valve shall be tested in the direction annulus to process piping.	
E. Use	1. The valve shall normally be open for monitoring purposes, with another valve isolating the access to the platform system, which should only be opened for the purpose of adjusting the annulus pressure.	
F. Monitoring	1. Sealing performance shall be monitored through continuous recording of the annulus pressure measured at wellhead level.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Inability to maintain a pressure seal. 2. Seeping or sweating valve surface.	

Acceptance table for the casing cement well barrier

Table B. 8: Acceptance table for casing cement. (NORSOK standard D-010 2004, Table 22)

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 **General:** Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 **Conductor**: No requirement as this is not defined as a WBE. 5.3 **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 **Casing through hydrocarbon bearing formations**: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class 'G'
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for "wellhead"
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

Acceptance table for the completion string

Table B. 9: Acceptance table for the completion string. (NORSOK standard D-010 2004, Table 25)

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string as WBE is to provide a conduit for formation fluid from the reservoir to surface or vice versa.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have gas tight connections whenever exposed to hydrocarbons during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to • tensile and compression load exposure, • burst and collapse criteria, • tool joint clearance and fishing restrictions, • tubing and annular flowrates, • abrasive composition of fluids, • buckling resistance, • metallurgical composition in relation to exposure to formation or injection fluid, • HPHT: Strength reduction due to temperatures effects.	
D. Initial test and verification	1. Pressure testing to METP. 2. HPHT: The tubular load bearing component of the completion string should be MPI inspected prior to HPHT exposure.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the completion string is located inside the BOP.	
F. Monitoring	1. Pressure integrity is monitored through the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak to or from the annulus.	

Acceptance table for surface production tree

Table B. 10: Acceptance table for surface production tree. (NORSOK standard D-010 2004, Table 33)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>This element consists of a housing with bores that are fitted with swab-, production master-, kill- and flow valves.</td><td></td></tr>
<tr><td>B. Function</td><td>Its function is to
• provide a flow conduit for hydrocarbons from the tubing into the surface lines with the ability to stop the flow by closing the flow valve and/or the master valve,
• provide vertical tool access through the swab valve,
• provide an access point where kill fluid can be pumped into the tubing.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. The surface production tree shall be equipped with
• one automatic master valve and one automatic wing valve in the main flow direction of the well,
• if the production tree has flowing side outlets, these shall be equipped with automatic fail-safe valves at short interval from the tree,
• one manual swab valve for each bore at a level above any side outlets,
• isolation valves on downhole control lines which penetrates the production tree block.
2. All primary seals (inclusive production annulus) shall be of metal-to-metal type.
3. All connections, exit blocks etc. that lies within a predefined envelope shall be fire-resistant.</td><td>API Spec 6FA, API Spec 6FB and API Spec 6FC</td></tr>
<tr><td>D. Initial test and verification</td><td>1. The valves shall be tested with both low and high (MEDP) differential pressure in the direction of flow. The low pressure test shall be 3,5 MPa.</td><td></td></tr>
<tr><td>E. Use</td><td>1. Employ a strategy for use of antifreeze/hydrate agents during shut-ins and testing.
2. Beware of equalization during opening and closing of valves.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>1. The principal valves acting as barriers in the production tree shall be tested at regular intervals as follows:
• test duration shall be 10 min,
• monthly, until three consecutive qualified tests have been performed,
thereafter -
• every three months, until three consecutive qualified tests have been performed,
thereafter –
• every six months.
2. If the leak rate can not be measured directly, indirect measurement by pressure monitoring of an enclosed volume downstream of the valve shall be performed.</td><td></td></tr>
<tr><td>G. Failure modes</td><td>Non-fulfillment of the above mentioned requirements (shall) and the following:
1. Failure to pass the regular test.</td><td></td></tr>
</table>