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Abstract

When oil and gas wells reach the end of their production life, they need to be permanently plugged and abandoned. The requirements for a permanent barrier state that it must cover the entire cross-section of the wellbore, including all annuli. This thesis evaluates a new method of establishing a cross-sectional barrier in areas with poor, non-sealing annular cement.

The traditional method is to mill away the section with poor cement and set an open hole cement plug, but due to the ECD effect of milling fluids, this is not always desirable. In some formations on the Gullfaks field, the operational pressure window is too small for section milling. An alternative solution was therefore tried out on a well that needed plugging.

This method, referred to as punch and squeeze, consisted of perforating the section of poorly cemented casing and squeezing cement into the annulus. In this thesis, the equipment and techniques used are presented and evaluated, along with general theory relevant to plugging and abandonment.

On Gullfaks, two punch and squeeze techniques were used. In the first, cement was pumped through a packer plug and squeezed into the perforations. The second technique involved setting a balanced cement plug over the perforations, and squeezing this plug into the perforations.

The main conclusions are that the technique using a packer plug is safer with regards to well control, involves less waiting on cement and gives a better annular seal than the balanced plug alternative. Also, a cement evaluation log should be run before the squeeze jobs are performed, and the log results should be used when determining where to perforate. All things considered, it was found that the punch and squeeze method can succeed in creating a length of cross-sectional cement, but still involves some uncertainty and the technique can be further optimized.

Preface

The work with this thesis was performed at Statoil's offices in Bergen. I would like to express my gratitude to Statoil and the Drilling & Well Support group in Bergen for giving me the opportunity to write this thesis.

I would especially like to thank my supervisor at Statoil, Jofrid Marie Hegreberg, for introducing me to the field of plug & abandonment, for shearing your knowledge and insight, and for providing feedback regarding the work.

Also, I would like to thank my instructor at the University of Stavanger, Bernt S. Aadnøy for providing guidance and inspiration during the work with this thesis.

Finally, I would like to thank my future colleagues at Gullfaks for letting me attend the morning meetings and for answering all my questions about the operations.

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List of abbreviations

APOS	Arbeids Prosess Orientert Styring
CBL	Cement Bond Log
DHSV	Down-hole safety valve
ECD	Equivalent circulating density
EZSV	Easy Sliding Valve (drillable packer plug)
FBP	Formation breakdown pressure
FCP	Fracture closure pressure
FIT	Formation Integrity Test
FPP	Fracture propagation pressure
GFA	Gullfaks A
GFC	Gullfaks C
HMX	a nitroamine high explosive
HSD	High Shot Density
ID	Inner diameter
ISIP	Instantaneous shut-in pressure
LCM	Lost Circulation Material
LOP	Leak-off pressure
LOT	Leak-Off Test
NCA	Norse Cutting & Abandonment
NCS	Norwegian Continental Shelf
NPD	Norwegian Petroleum Directorate
NPT	Non-productive time
OD	Outer diameter
OWC	Oil-water contact
P&A	Plug and abandonment
PSA	Petroleum Safety Authority Norway
RDX	an explosive nitroamine, short for Research Department composition X
spf	shots per foot
TCP	Tubing Conveyed Perforation
TDF	Time-Delayed Firer
TOC	Top of cement
USIT	UltraSonic Imager tool
VMB	V-series Mechanical Barrier plug – a retrievable plug from Seawell Oil Tools
WBE	Well Barrier Element
WBEAC	Well Barrier Element Acceptance Criteria
WBM	Water based mud
WOC	Wait on cement
XLOT	Extended Leak-Off Test

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1 Introduction

On offshore platforms, the number of slots available for drilling wells is often limited. As fields mature, wells may be shut down for a number of reasons, and there may also be a need to drill new wells to keep up production. The solution is often to plug an old well and drill a sidetrack to the new geological target. Since the access to the mother bore may be limited after the sidetrack is drilled, the old section is often permanently plugged and abandoned, which implies using materials and techniques that are designed with an eternal perspective.

Unfortunately, old wells may not have been designed with abandonment in mind, or may have experienced problems that can cause difficulties when permanent plugging these wells. One of these problems is that some wells do not have sufficient annular cement to comply with the requirement that a permanent barrier plug should cover the entire cross-section of the well, including all annuli. If there is no cement in the annulus, the casing can be cut downhole and pulled out before setting a cement plug.

However, if the casing is partially cemented it may not be possible to pull it out of the well, so an alternative method is needed. Today, the method most frequently used on the Norwegian continental shelf (NCS) is section milling. A limited section of the casing is then milled away so that a cement plug can be placed in the open hole. Due to the heavy steel cuttings that are generated, a viscous milling fluid is needed to transport the cuttings out of the well. This viscous fluid causes a noticeable ECD (equivalent circulating density) effect, which may cause problems in wells with a small operational pressure window.

On Gullfaks A, a well needed to be plugged so that a sidetrack could be drilled. In this well, the anticipated pressure window was too small to use section milling, so it was decided to try out a new technique for establishing a cross-sectional cement plug. This technique, referred to as punch and squeeze, consisted of perforating the casing and squeezing cement into the poorly cemented annulus. If successful, the method had the potential to partially replace section milling.

The aim of this thesis is to evaluate the punch and squeeze method and see if it should be used in future wells.

The first part of the thesis gives an overview of basic theory and regulations relevant to plug and abandonment (P&A).

After that, a description is given of some of the challenges specific to Gullfaks and two of the wells that have recently been plugged on the field.

The equipment used with the punch and squeeze method is then presented before the method is described. A summary of the plugging of a specific Gullfaks A well, where the punch and squeeze method was used, is then given.

Also, a handful of alternative techniques and materials are presented that could be used to either establish a cross-sectional barrier or be an alternative to cement as an annulus material.

Finally, the results from the Gullfaks A well are discussed and a conclusion is given on the future potential of the method and recommended improvements.

2 P&A in general

As mentioned, well slots are often re-used in offshore oilfields for drilling new wells [1]. This is typically done by plugging old well sections that have reached the end of their production life and drilling a sidetrack into a new area. Norwegian legislation requires that the old part of the well is abandoned with two well barriers, or prepared so that two barriers can be established at a later stage, when drilling a sidetrack into a new area of the reservoir [2]. If the primary cement job is inadequate, a well will need expensive remedial work to comply with the requirement that permanent well barriers shall extend to the entire cross-section of the well, including all annuli [3].

The main purpose of a permanent P&A is to isolate the subsurface formations that are penetrated by the well [4]. While it is important to seal the reservoir, a good P&A should also seal all other fluid-bearing formations, especially if they have higher pressure than the hydrostatic water gradient. In addition to preventing fluid from migrating from the subsurface formations to the surface, the P&A should also prevent the fluid from flowing from one subsurface formation to another, so called cross-flow.

There are several reasons why it is important to properly isolate the formations penetrated by a well. The most obvious reason is to prevent oil or gas from leaking to surface, which may pose a threat to the environment and may also be a safety risk. An aspect that is perhaps not so important on the NCS is that many countries use groundwater as a resource for drinking water [4]. When this is the case, it is important not to contaminate aquifers with cross-flow from oil and gas reservoirs, which could disqualify the aquifers as a source of drinking water. Gas can be especially dangerous if it enters the water pipe system, since this may in worst case enter households and come out of taps when these are turned on [5].

On the NCS and other areas where drinking water is not a concern, there is still reason to avoid cross-flow. In producing fields, it is important to maintain reservoir pressure to conserve the energy that is used to produce oil and gas [6]. Although a well is being abandoned, there may be other wells in the same reservoir section that are still producing, so communication along an abandoned well is not desirable, since this can direct pressure away from the reservoir.

Another effect of cross flow from a producing reservoir is the pressure in the formations above the reservoir may increase. This may re-activate old faults, decrease the pressure window for drilling and may increase the uncertainty in pore pressure prediction [7]. The increased pressure may therefore lead to considerable drilling problems and should be avoided.

3 Rules and regulations

Permanent plugging of wells on the Norwegian Continental Shelf (NCS) is governed by The Activities Regulations issued by the Petroleum Safety Authority Norway (PSA). These regulations state that the NORSOK D-010 standard should be used as a minimum functional requirement for well operations in Norway [8, 9]. This implies that alternative solutions to the standard may be used, as long as the solution can be proven to be equally good or better than the NORSOK D-010 requirement.

Statoil also has its own steering documents, APOS, which regulate the way Statoil performs its operations. APOS contains guidelines for all of Statoil activities, but the section that is relevant for P&A operations is the *Well Integrity Manual* and the subsection *Well Barrier Element Acceptance Criteria* [10]. Many other NCS operators also have their own company-specific governing documentation; however these often come from international headquarters and dictate the use of local regulations in addition to or instead of the company guidelines where applicable [4, 11]. As Statoil has its main activities in Norway, the *Well Integrity Manual* is to a large degree based on NORSOK D-010 with some adaptations and further specification.

3.1 Barriers

NORSOK defines a well barrier as "*an envelope of one or several dependent WBEs* [Well Barrier Elements] *preventing fluids or gases from flowing unintentionally from a formation into another formation or to surface*." [12] In general, it is required that a well always has two verified well barriers available when the pore pressure is high enough to potentially cause an uncontrolled flow from the well to the environment. If possible, these two barriers should be independent and not have common WBEs. However, a common WBE may be accepted if a risk analysis is performed and risk is reduced to as low as reasonably practicable.

The WBEs should be pressure tested before use, preferably in the flow direction [13]. If a WBE is designed to seal in both directions, it can be tested against the flow if the former is impractical. Otherwise an inflow test can be performed, which implies reducing pressure on the downstream side of the barrier to a minimum practical pressure.

NORSOK gives a number of acceptance criteria for the most commonly used WBEs and also describes a methodology for defining acceptance criteria [14]. The acceptance criteria specify the function, design, verification methods, monitoring and failure modes of the WBE in question. This should be set up in a table as described in NORSOK (see appendix).

3.2 Permanent P&A

Because permanently plugged wells have to be abandoned with an eternal perspective, the general principle of two well barriers is not adequate for permanent plug & abandonment (P&A) [3]. In addition to the primary and secondary barriers, an open hole to surface well barrier and a well barrier between reservoirs is required. The purpose of the open hole to surface barrier is to isolate the hole from the surface that is exposed after the casing has been cut and to act as the final barrier against flow.

The position of the well barriers should be as close as possible to the potential source of inflow and at a depth where the formation fracture pressure is estimated to be larger than the potential inside pressure [3]. APOS requires that a permanent plug be set at a depth where the minimum formation stress, instead of fracture pressure, is larger than the potential pressure, see chapter 3.6.

NORSOK also states that the original wellbore should be permanently abandoned before a new side-track is drilled [3]. APOS allows for temporary abandonment of the mother bore, provided that permanent barriers can be placed during the final well abandonment phase. The UK requirements have been revised in 2009, and this revision has a similar statement to the APOS requirement [2].

Using the interval between a liner top and casing shoe, the liner lap, as a permanent WBE is briefly mentioned in NORSOK [3]. It states that cement in a liner lap should not be used as a part of the permanent barrier unless it has been leak tested from above. If there is a liner top packer, the leak test should have been performed before the liner top packer was set, since the packer is not an acceptable permanent WBE. However, Statoil have made a procedure for qualifying cement in the liner lap as part of the permanent well barrier. APOS requires the following methodology to be applied:

- *"Length/height of cement and cement bonding shall be identified through appropriate logs*
- *Appropriate logging tools (one or two independent logging measurements/tools) shall be applied to provide high quality logging data for the actual well conditions*
- *Logging tools shall be suitable for applicable well conditions e.g. number of casing strings, casing dimensions and conditions, fluid types and densities*
- *Logging tools shall be properly calibrated*
- *Logs shall be interpreted by personnel with sufficient competence*
- *Log response criteria for good bonding shall be established prior to initiating the logging operation"* [10]

Generally, radioactive sources should not be left in an abandoned well [15]. However, if this becomes necessary, the Activities Regulation states that general requirements on permanent plugging in NORSOK D-010 should be met, but with the following additions:

- *"An internal overview over left behind sources should be established and maintained. The overview should contain details about every single source and its position,*
- *Radioactive source left behind in work strings should be secured in a manner which clearly indicates any unintentional drilling close to/in the direction of the source's position."* [15]

3.3 Permanent P&A – requirements and desired properties

An important and challenging requirement for a permanent well barrier is that it must include all annuli, extending to the full cross section of the well and seal both vertically and horizontally, as seen in Figure 1. A cement plug set inside the casing must therefore be placed at a depth with verified cement, or an equivalent WBE, in all annuli [3].

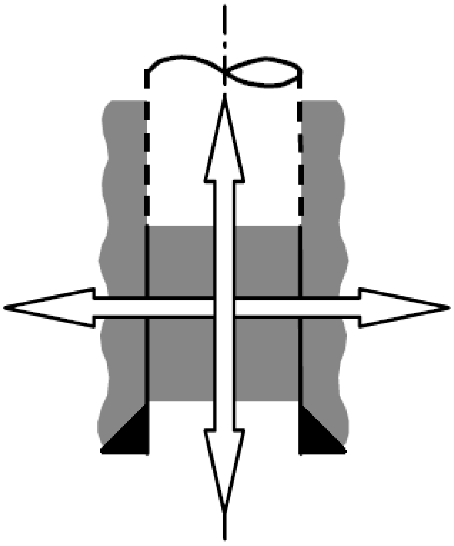

Figure 1 - A permanent well barrier shall seal both vertically and horizontally. [16]

NORSOK defines 6 properties that are desired from a permanent well barrier, but not required [3]:

> *" a) Impermeable*
> *b) Long term integrity.*
> *c) Non shrinking.*
> *d) Ductile – (non brittle) – able to withstand mechanical loads/impact.*
> *e) Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons).*
> *f) Wetting, to ensure bonding to steel."* [16]

The third issue of the UKOOA Guidelines for the Suspension and Abandonment of Wells, released in January 2009, also defines these same 6 properties as desired characteristics [2].

When planning a permanent P&A, NORSOK gives a number of requirements to the design basis and which information it is advised to collect as a minimum. For abandonment using cement, NORSOK states that the design basis should account for uncertainties regarding the following:

- *"downhole placement techniques,*
- *minimum volumes required to mix a homogenous slurry,*
- *surface volume control,*
- *pump efficiency/ -parameters,*
- *contamination of fluids,*
- *shrinkage of cement."* [16]

Furthermore, NORSOK recommends gathering the following data:

- *"Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc.*
- *Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.*
- *Logs, data and information from primary cementing operations in the well.*
- *Estimated formation fracture gradient.*
- *Specific well conditions such as scale build up, casing wear, collapsed casing, fill, or similar issues."* [16]

3.4 Materials

Since NORSOK D-010 rev. 3 is meant to define minimum functional requirements, it generally tries to avoid specifying material type, and instead defines the functional requirements that the material must fulfil [3]. It does however mention a couple of materials that are not acceptable parts of a permanent well barrier:

> *"Steel tubular is not an acceptable permanent WBE unless it is supported by cement, or a plugging material with similar functional properties […].*
>
> *Elastomer seals used as sealing components in WBEs are not acceptable for permanent well barriers."* [3]

Since bridge plugs use elastomer seals, these cannot be used as permanent WBEs. However, they can be used to provide a solid foundation for cement plugs to avoid slurry contamination [17]. Although cement plugs are usually required by NORSOK to be verified, an exception is made for cement plugs set in casing on top of a tagged and pressure tested bridge plug [14]. Given that the bridge plug has already been pressure tested, a new pressure test would not reveal any potential leaks in the cement plug.

3.5 Formation as a well barrier

In the drilling phase, some formations are known to cause problems by moving into the well and potentially causing the drill pipe to get stuck [1]. Even though this effect is seen as a problem in the drilling phase, it can be used to create an annular barrier outside the casing when abandoning a well or well section. Statoil have developed a procedure to qualify the use of shale formation as an annular barrier, and this method has been accepted by the Norwegian PSA.

As will be discussed later, creating a barrier that extends across the entire cross section can be problematic if the primary cement job was not entirely successful [8]. While the casing is sufficient as a barrier element in the drilling and production phases of a well, unsupported steel tubular is not an acceptable barrier element in the permanent plugging and wellbore abandonment phase [3]. These wells may need expensive remedial work to place a sufficient cement barrier outside the casing.

If one could avoid the use of existing remedial work and instead use formation that has enclosed the casing as an annular barrier, then considerable time and money could be saved [1]. However, the formation has to meet certain criteria to be qualified for this use, such as having a very low permeability and sufficient strength to withstand the maximum pressures expected.

The formation should also be detected by bond logs [1]. Previously, cement bond logs (CBL) have often shown good bonding far above the theoretical top of cement (TOC). There are most likely several causes to these log responses, but the most common cause is believed to be formation displacement reducing the wellbore diameter.

Several mechanisms occur in displacing the formation, both in isolation and in combination [1]. The two most important mechanisms are believed to be creep and shear failure, of which creep is seen as the most dominating. Shear failure is usually seen in shale formations that require the wellbore pressure to be higher than the pore pressure to remain stable. Over time, the mud behind the casing may degenerate, causing the density to decrease and therefore initiating failure. However, since logs reveal distinct layers with no bonding between layers showing good bonding to casing, it has been concluded that this is not a "rubble zone" which would be expected if the displacement mechanism was shear failure alone.

Creep is a deformation mechanism that is time-dependant and can occur in materials in constant stress [18]. The cause of plastic creep is that the overburden pressure gives the formation visco-elastic properties [8]. Temperature effects generally increase the speed of the deformation since creep is a molecular process.

To qualify a formation it is important that the maximum reservoir pressure that the barrier can see does not exceed the minimum horizontal stress [1]. In order to be sure of this, a strength test should be performed. Another objective of the strength test is to check that there is no fluid communication outside the casing. The test could be either a formation integrity test (FIT), a leak off test (LOT) or an extended leak off test (XLOT), but an XLOT is preferred since this can determine both formation strength and potential communication issues.

3.6 Minimum formation stress

During drilling, the formation strength is tested after a casing string has been set and cemented and a few meters of fresh formation has been drilled out [19]. This is primarily done to make sure that the cement and formation is strong enough to withstand the loads required for the next section. The normal way to do this is with a LOT, where the well pressure is increased until the pressure versus time trend is no longer linear. At this point, referred to as the leak-off pressure (LOP); the test is stopped before the formation break-down pressure (FBP) is reached, see Figure 2 [20]. In some cases, it is not desirable to pressurize the well all the way up to the LOP, in which case the well is pressured up to the pressure required to drill the next hole section [21]. This technique is called a FIT, and does not provide as much information about the formation stresses as other methods. Finally, the formation strength can be tested with an XLOT. This is much like a LOT, but instead of stopping before the formation fractures, pumping is continued well past the FBP, so that additional information like FBP, fracture propagation pressure (FPP), instantaneous shut-in pressure (ISIP) and fracture closing pressure FCP can be obtained. Also, an XLOT is usually repeated at least once.

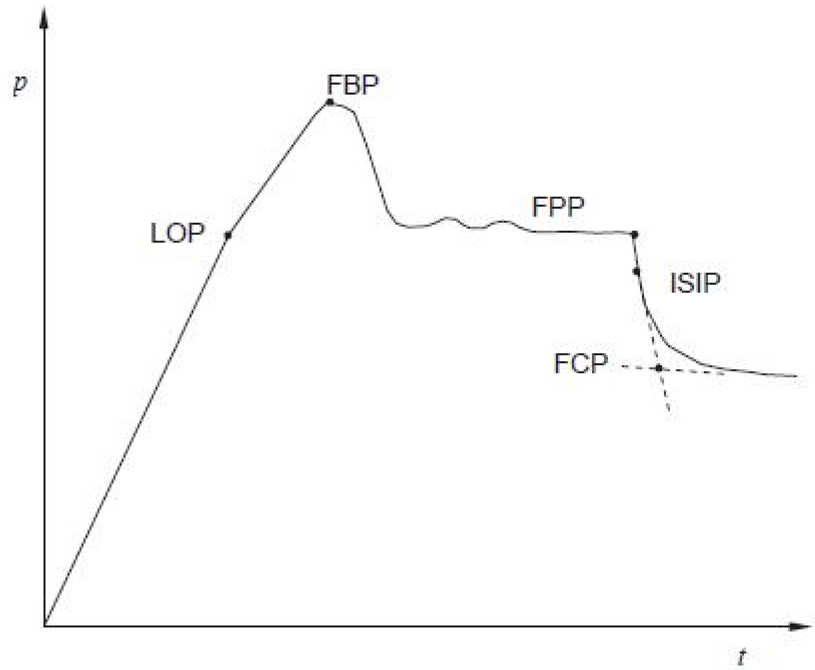

Figure 2 - An illustration of an XLOT with some associated abbreviations [20]

Statoil's steering documentation APOS has recently been changed to give stricter requirements for formation strength than NORSOK D-010 [10, 16]. As mentioned, NORSOK requires that a permanent WBE is set at a depth where the potential pressure is less than the fracture pressure, while APOS instead requires these to be set where potential pressure is less than the minimum formation stress. This is also the case for the required depth of setting the production packer and several other cases where fracture pressure is mentioned in NORSOK.

The main reason for replacing the term "fracture pressure" with minimum formation stress is that a new method is believed to give a more accurate description of the minimum in situ stress than the traditional interpretation of a LOT [20]. In this method, minimum formation stress is found by interpreting a properly performed XLOT with flowback. This flowback phase is where Statoil's new method differs from a regular XLOT. After the XLOT has been performed, the pressure is bled off through a constant choke while continuously measuring the volume of drilling fluid that is bled off, and these measurements can be plotted in a graph showing the square root of pressure versus time. When the fracture generated by the XLOT closes, the slope in this trend changes, giving an indication of fracture closure pressure.

Since FITs, LOTs and XLOTs are performed with drilling fluid, it is likely to assume that a filter-cake may have developed on the borehole wall that can increase the fracture pressure compared to if a penetrating fluid had been used [22]. Therefore, an FIT or LOT can give valuable information for the drilling phase of the well, but should not be used as a value of formation strength when using other fluids, such as clear brines, without having in mind the effect of the filter-cake in the original test. Throughout the lifetime of a well, including the P&A phase, it is possible that the barriers will be in contact with penetrating fluids, which is a reason why Statoil have changed the phrasing of their requirements from "fracture pressure" to "minimum formation stress".

4 Well integrity

NORSOK D-010 defines well integrity as the “application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the lifecycle of a well.” [16] This is a widely accepted definition, not just in Norway, but throughout the industry [23-25]. It is worth noting that “throughout the lifecycle of a well” implies that well integrity also covers the final stage in the life of a well, permanent P&A.

During recent years there has been an increased focus on well integrity and there have also been conducted studies to try to get an overview of what the current situation is on existing wells [5, 25]. One of these projects was carried out by PSA in 2006 to get an overview of integrity problems with wells on the NCS [26]. This was a comprehensive survey that included input data from 12 pre-selected offshore facilities that were operated by 7 different oil companies. From these, a total of 406 development wells were selected that would give a representative collection of injection and production wells with varying age and development category. Although these wells did not include P&A wells, they do give insight into the general well integrity status of NCS wells. The study showed that 18% of the wells in the survey had well integrity issues, and that 7% of these were shut in due to integrity issues as of 01.03.06.

Many of the integrity problems related to e.g. DHSV (down hole safety valve) and tubing leaks are problems that will not cause great problems with P&A since these will be removed, however problems related to the cement are relevant to permanent P&A as the existing cement is often used as a permanent WBE. The results from the survey showed that most of the integrity issues occur in wells from early 1990s and onwards [26]. With regards to cement, there were 8 wells where cement had failed as a WBE and all of these 8 wells were less than 14 years old when the survey was conducted, meaning that they were all constructed in the period from 1992-2006. This indicates that the cement could continue to cause problems in future P&A of wells. Although these 8 wells only account for approximately 2% of the total 406 wells, there could well be many more that have sufficient cement for the production phase, but not for the abandonment phase.

When PSA summarized areas that the operators could improve on, documentation was mentioned as an area where all 7 operators could improve [26]. Especially the fact that casing cement is often not properly verified introduces increased uncertainty when planning a P&A.

5 Cementing

Well cementing is generally divided into primary cementing, which is done after running a casing or liner, and secondary cementing, which can often comprise of remedial work such as squeeze and plug cementing [27]. Oilfield cements can have a vary in complexity, but are usually based on Portland cement [28]. When dry cement is mixed with water, a reaction called cement hydration is started. As the hydration proceeds, the cement increasingly sets to a stone-like solid [17].

Since there may be small differences between different brands of cement in the same class, a test should be completed under simulated well conditions to determine the properties of the specific cement slurry with additives [28].

5.1 Primary cementing

After running a casing string to the desired depth, the casing is cemented to the formation. This cement job is referred to as primary cementing [28]. The purpose of the primary cement is to seal the annulus between casing and formation, support the casing structurally and protect the casings exterior from corrosion, among other things. Several techniques for primary cementing exist, but single-stage cementing is the most frequently used method. This technique consists of pumping a given volume of cement slurry displaced by another fluid through the casing, around the shoe and into the annulus.

Another method is multi-stage cementing, where cement is pumped in two or more individual stages to seal the annulus [28]. This may be used if the fracture gradient is critical or if good cement is required in a long casing string. To perform this kind of operation, special multi-stage devices are needed. These stage collars have ports that can allow cement to be pumped into the annulus behind the casing. The first stage of cementing is carried out in the same way as a single stage cement job by pumping down cement to fill the lowermost section of the casing. The stage collar is then hydraulically opened to allow the following cement to enter the remaining upper section and then closed, remaining a part of the casing string.

5.2 Squeeze cementing

Another form of cementing is squeeze cementing. This is the technique of applying hydraulic pressure to a slurry to force it into a given area and allow the cement to harden to form a seal [17]. The given area may for example be splits in the casing, annular spaces and/or perforations [29]. Squeeze cementing is used during drilling and completion, but also has applications in the abandonment phase of the well. Perforations can be squeezed to seal the reservoir, but when counting meters of barrier cement against a formation, one should start at the top of the reservoir or formation and count upwards [16]. Also, squeeze cementing can be used for establishing a full cross-sectional barrier, as will be described in chapter 12.

One of the biggest challenges with squeeze cementing is placing the right amount of cement at the right place [17]. There are two main techniques for performing a squeeze job; the Bradenhead method and the squeeze tool method.

The Bradenhead method consists of pumping cement through tubing or drillpipe and closing the BOP when the cement is near the bottom of the string [17], see Figure 3. In this way the fluid in the well is confined, and continued pumping will increase the pressure and force the cement into the area of least resistance. Using this method, a packer or plug is not used, so there is a larger area that is exposed to pressure, which increases the uncertainty in where the cement is actually placed.

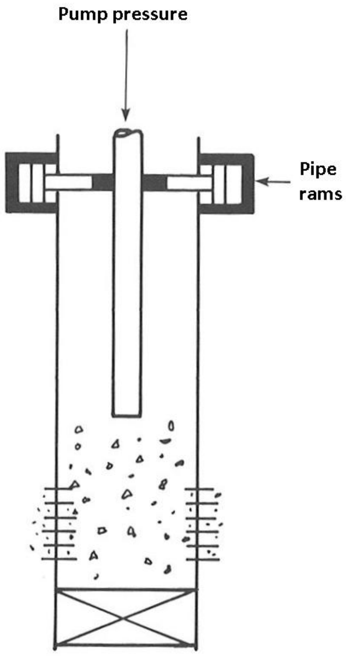

Figure 3 - Bradenhead squeeze [30]

The other method of squeeze cementing is referred to as the squeeze tool method [17]. This is illustrated in Figure 4. Here, a packer or plug is set in a position at the top of the area to be squeezed and cement is placed in the confined area. A bridge plug or cement plug may also be set under the perforations to isolate the area receiving the treatment from the section below.

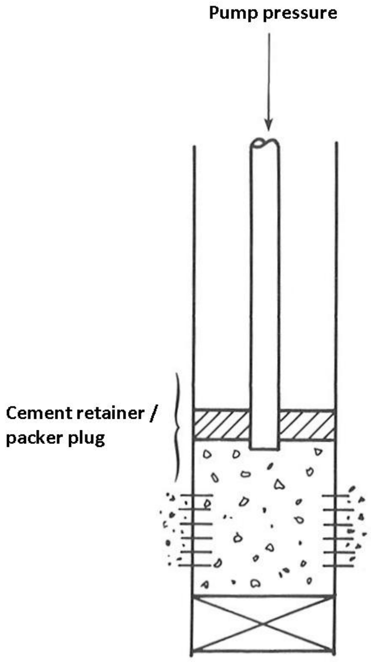

Figure 4 – Squeeze tool method [30]

In addition to these two methods, there can be other techniques or variations. A variation of the Bradenhead squeeze is to first place a balanced cement plug over the treatment area and then closing the annular before squeezing the plug from above, as described in chapter 12.

Furthermore, squeeze jobs can be divided into high-pressure and low-pressure squeezes [17]. High pressure jobs are operations where the cement is placed at pressures that exceed the fracture pressure of the exposed formation. This type of squeeze may be required if drilling mud with a certain amount of solids is present in front of the cement, if no voids exist behind the casing or if a number of other operational conditions dictate the need for this type of treatment.

However, the most common type of squeeze cementing is low-pressure squeezing below fracture pressure [17]. Compared to high-pressure jobs, they often require less cement and usually give better control over placement. As long as voids exist then low-pressure squeezes can usually be used, provided that the fluid that is displaced in front of the cement is a clean, solids-free fluid.

5.3 Cement plugs

Cement plugs play an important part in many operations throughout the lifetime of the well, including lost circulation, zonal isolation, kick-off and abandonment [17]. Setting a quality cement plug is therefore dependent on good job planning, taking the specific well conditions into account.

The balanced method is a simple and common technique used for setting a cement plug that does not require special equipment [31]. It is placed by an open-ended drillpipe that is run to the desired bottom depth of the cement plug. Cement is then pumped down the drillpipe and circulated back up the annulus until the cement inside the string is the same height as outside the string. The drillpipe is then slowly pulled out whilst circulating so that the cavity in the plug is filled. To minimize the movement in the cement plug when pulling out, the diameter of the pipe used should be small, allowing a larger cement volume in the annulus. This should help to mitigate the chance of contaminating the cement with mud, which is a major concern, especially with small volumes of cement. Also, balanced plugs in highly deviated wells are prone to failure due to gravity effects.

Although cement plug operations have been considered to be relatively simple, they have historically been prone to failure [17]. The main problem is that the cement can be contaminated by other fluids, such as drilling fluids, preventing the cement to form a competent plug.

Which fluid is in the wellbore prior to performing the job is therefore an important factor in the success or failure of the job [17]. In many cases the well is filled with drilling fluid, which gains gel strength after being static for a sufficient period of time. This can cause problems when trying to place the cement slurry, since the cement can channel through the gelled mud rather than displace it.

Furthermore, the mud density and composition also influence the outcome of the cement plug [17]. In many cases, it may be necessary to use cement slurry with a higher density than the well fluid. This difference in density may lead the heavier cement to sink into the well fluid, causing cement contamination and misplacing the plug, an effect referred to as the u-tube effect [32]. Setting a bridge plug or another solid foundation before placing the cement can help mitigate this effect.

The chemical composition is important because the mud system can contain several additives that may have a detrimental effect on the cement [31]. Some of these additives, such as lignosulphonate, can act as a severe retarder, causing problems in determining thickening times and decreasing the overall strength of the cement plug. In addition to chemical effects, the drilling fluid may also cause dilution of the cement slurry, again leading to a weaker plug. To avoid these problems, a sufficient volume of spacer is needed in front of the cement [17].

6 Existing technology

Ideally, the well section that is going to be abandoned has a long interval of verified good cement outside the casing. Verification can be in the form of cement evaluation logs or operational parameters, i.e. that everything has gone according to plan with full returns etc. If the verification is positive, a cement plug of sufficient length can be placed inside the casing without further complications. This internal cement plug can then be verified by applying mechanical force to check its location and strength, followed by a pressure test to verify its sealing abilities.

However, a complete layer of good cement in the annulus is not always the case for wells that are going to be abandoned. There could either be no cement in the annulus, or the cement could be of low quality, with limited sealing capability. Today there are basically two methods that are used to achieve a permanent cross-sectional barrier in wells without good annular cement.

6.1 Cut and pull

If the annulus contains no cement, then the casing can be cut above the casing free point and the casing above pulled out of hole. This free point can for example be found by performing a stretch test in much the same way as with drill pipe.

However, it is often necessary to cut higher than initially planned and remove the casing in several steps. This leads to extra trips in and out of hole, and can be time consuming.

6.2 Section milling

If there is cement or other obstructions in the annulus, it may not be possible to pull the casing. Another method must therefore be used to create a cross-sectional barrier if the annular material does not qualify as an annular barrier.

The most common method is to mill away the casing section with bad cement in the annulus [1, 33]. Once the section of casing has been milled, the hole is reamed before a cement plug can be set in the section milled area to form a full cross-sectional barrier. However, as will be discussed later, section milling can be unreliable and in some cases practically impossible with existing technology.

Section milling is a technique that creates an interval where the casing and cement has been removed and there is direct exposure to the formation [34]. This is done by running a section milling assembly to the desired depth, extending cutting blades to cut through the casing, and then weight is applied to mill the interval in question. The cutting blades are operated via a piston and cylinder that responds to pump pressure.

6.2.1 Swarf transport

To transport the cuttings generated by milling, also known as swarf, a special milling fluid or fit for purpose mud should be used [34]. The steel drill cuttings generated by milling has a density of around 7.8 g/cm^3, which is substantially higher than the sedimentary formation that is usually encountered when drilling, often having a density of roughly 2.6 g/cm^3 [35].

Therefore, the fluid needs to be viscous enough to carry the metal cuttings, but without being too viscous, in which case the mud can channel, especially in highly deviated wells. Also, if the fluid is too viscous, the ECD effects could cause problems with wellbore stability. In areas with weak formation or a small operational pressure window, it is important that this is considered when planning for hole cleaning.

In addition to rheology, flow rates are important in cuttings transport and hole cleaning [35]. The two most important factors in achieving good hole cleaning when milling is having a high enough annular velocity and carrying capacity. If the mill has nozzles that can be adjusted, these should be adjusted to maximize flow rate.

If good hole cleaning is not achieved, we may get what is referred to as a “birds nest”. This is a build up of entangled steel slices that have got stuck in the well [35]. These usually accumulate in areas with reduced annular velocity, for example at a liner hanger, in the BOP or in the riser. Modern mills are designed to create short metal chips to mitigate this effect; however these chips may also build up to form small balls that in turn may generate bird nests. A bird nest in the BOP can restrict the flow and cuttings transport, and may in some cases restrict pipe movement. Steel cuttings in the ram area of the BOP may also create flow paths that could lead to a bad BOP test. It is therefore recommended to clean the BOP cavity after milling is completed.

It is also important to consider the surface equipment when milling [34, 35]. Flow lines should have gentle bends, good clean-out capabilities and sufficient drop to avoid accumulation of cuttings. If fine steel particles are not removed from the fluid, they can damage pumps and other rig equipment, so it is important to remove as much of these as possible. Therefore, magnets are often used to remove the steel particles that went through the shaker screens. The steel that is collected from the screens and magnets is often weighed to estimate the amount of steel cuttings left down hole that may cause problems. Specially designed swarf units may also be used to remove swarf from the milling fluid.

7 Examples of problems

7.1 Primary cementing - placement

A major concern in primary cementing is adequate displacement of mud and placement of cement. If the cement bypasses the drilling fluid, this could create channels that form a flow path along the cement sheath [36]. Through the years there have been a number of developments and research that has been conducted on the subject of mud displacement [37]. The result of this is that mud displacement today is done by using spacers that leave the casing and formation water-wet and are compatible with both cement and drilling fluid. Also, the spacer system should be able to go into turbulent flow at a sensible pump rate and have a density that is higher than the mud weight, but lower than the cement. In addition to the spacer system, there are a number of factors that should be considered.

7.1.1 Wellbore geometry

An important factor that influences both mud displacement and cement placement is the wellbore geometry [37]. Incorrect interpretation of borehole geometry can lead to over- or underestimation of well volumes, which in turn may lead to pumping an incorrect volume of cement. If the cement volume is underestimated, the TOC may also be lower than desired. Such misinterpretations may be caused by a misunderstanding of how round or oval the well is, in other words how large variations in radius there is in a single cross-section.

Another wellbore geometry consideration that should be addressed is the variation in diameter in different cross-sections along the well [37]. The larger diameter sections are often referred to as washouts, and these sections will have a lower flow velocity than in-gauge sections due to the larger cross-sectional area. If the flow velocity is low enough, it may cause problems with removing cuttings and drilling fluid, and if these gel up, further problems with cement placement could be encountered.

7.1.2 Centralization

Casing centralization also affects mud removal during cementing [37]. Since cement flows more easily through a large space than through a narrow space, poorly centralized casing may risk that cement bypasses some of the narrow side, leaving a mud-filled channel. To make sure that casing is spaced out from the borehole wall, centralizers are placed at certain intervals along the casing. These intervals should be long enough to allow free passage for flowing fluids, but also short enough to prevent the casing from contacting the low side of the hole [28].

7.1.3 Pre-cementing circulation and pipe movement

Since most drilling fluids are shear-thinning, and can therefore gel up if left still, it can be beneficial to circulate the well prior to cementing the casing [37]. A thinner fluid is easier to displace than a thick fluid, so circulation that helps to break gels can improve mud displacement. Also, the presence of gas flow may be checked by circulating bottoms up, and circulation may help to remove anything inside the casing that could plug the floats.

Another step that can be taken to break up gels and improve mud displacement is to either rotate or reciprocate the casing [28]. This pipe movement can also divert fluid into washouts, further improving mud displacement [37].

7.1.4 Filter cake removal

To achieve good bonding between cement and the formation, it is necessary to properly remove the filter cake generated during drilling. A pre-flush fluid and the spacer fluid are usually used to clean out the well. In some areas, mechanical wall-cleaning devices that scrape off the filter cake are also used [28].

7.2 Primary cementing – cement failure

When using a cement plug as a part of a permanent well barrier, it is required that the plug extends to the full cross section of the well, including all annuli [3]. The plug is therefore dependent on the success and robustness of the primary cement job. It has been quoted that as much as 15 % of primary cement jobs in the United States fail [38]. There is a number of ways in which the casing cement can fail [39].

Casing cement has two interfaces, one between formation and cement, and one between cement and casing [39]. To retain integrity, both these interfaces need to have a good, undamaged mechanical bond. In the event that an interface is debonded, the result would be an annular opening that could fail to seal the zone that the cement was intended to. Debonding can be a result of cement shrinkage due to hydration volume reduction or casing expansion/contraction.

Another failure mode of the cement sheath is fractures caused by tensile stresses that exceed the tensile strength of the cement [39]. Since cross sectional cracking does not influence sealing capacity significantly, and hoop cracking is assumed unlikely since interface bonds are considered the weak point, radial cracking is usually the only type of fracture that is reported. Radial cracks may allow fluid communication both in radial and vertical directions.

Furthermore, the cement can loose its sealing and mechanical properties if it is exposed to a combination of compressive and shear stresses [39]. This can cause the cement to crumble and is referred to as shear deterioration. There are a number of ways that shear deterioration can appear, including micro-cracking, crushing or shear bands.

Moreover, the casing can be permanently deformed if the load exceeds the yield point [39]. Small deformations of the casing can cause larger loads being applied to the cement, which may in turn lead to cement failure.

There are a number of aspects to consider when planning a primary cement job [39]. In addition to correct placement, it is important to design the cement job so that it can withstand the conditions that the well will see through its entire lifetime.

Temperature effects can be challenging when designing a cement job [39]. If exposed to high temperature over a long period, cracks and channels may generate in the cement. If the well experiences extensive temperature variations, the casing may expand when heated up and shrink back to original size when cooled down again. This can cause cracking during expansion and may leave a void after contraction, called a micro annulus [28].

Pressure may have a similar effect on the casing [39, 40]. If the pressure is increased sufficiently, the casing may expand in the radial direction, an effect called ballooning. While the casing may be deformed elastically, the cement could deform plastically, leaving a micro annulus where fluid can flow [28]. When planning a cement job, it is important to consider all the pressures that the well may see, including pressure tests, acidizing, fracturing etc.

Finally, the thickness of the cement sheath affects how much the cement can withstand [39]. If the space between the casing and the borehole is sufficiently large, the cement will be better suited to absorb changes in casing or formation geometry.

8 Reservoir conditions

8.1 The Gullfaks field

The Gullfaks field is situated in the Tampen area, a part of the Viking Graben in the North Sea [41]. Due to the large area of the field, which is 50 km^2, Gullfaks was developed with three platforms, Gullfaks A, B and C in the second half of the 1980s. Geologically, Gullfaks was described as the most complex field that had been developed so far on the NCS when it was put on production [42]. There are a number of factors that contribute to this complexity, but the intricate fault patterns that split the field into many blocks is perhaps the main factor. These fault blocks make it necessary to drill a relatively large number of wells to drain the reservoir efficiently [43].

Also, there is a substantial difference in permeability throughout the reservoir zones [6]. The reservoir consists of sands in the Cook formation, Statfjord formation and Brent group, where the highly productive sands can cause sand control challenges due to poor consolidation. Sand production is particularly a problem after water breakthrough.

Even with all these challenges, Gullfaks has a high overall recovery factor of 56 % [6]. This has been achieved using a development strategy that uses a set of producers and injectors that are dedicated to a specific fault block unit of the reservoir [43]. The plan from the start was to maintain reservoir pressure above bubble point, and it was early realized that waterflooding would be the most suitable approach [42]. To use this approach, one injector generally gives pressure support to several neighbouring production wells. The injection well is placed within the same fault block as the producer at a distance from the OWC (oil-water contact) that gives a good sweep of the production zone. In highly productive zones, a few injectors with a high injection capacity are placed far from the OWC to give a uniform rise of the water level.

The Gullfaks field can be further split into three areas with three different types of structural geology. In the western and central area is a domino system consisting of rotated fault blocks [6]. To the east there is a so called horst complex, which is a raised fault block. This horst may have resulted in a graben between these two areas. The combination of eastward and westward dipping faults could have caused spatial problems that have resulted in some local reverse faulting in this mainly normal faulting area.

Because of the vast volumes of water that is injected, the conditions for bacteria that generate H_2S are favourable in some areas, especially around injection wells that are placed in the oil zone [6]. This has led to generation of H_2S in some parts of Gullfaks. Since H_2S is corrosive and very harmful to humans, this is a growing concern for the late-life stage of production.

8.2 Top Shetland

Water injection has also caused problems with pressure estimation in the formations above the reservoir [7]. Some of the water injectors have been injecting at pressures that exceed the strength the reservoir formation and also the cap rock. This is thought to be the cause of what has become a high pressure zone in the Top Shetland formation. A number of wells have confirmed that this zone has abnormally high pressure compared to the initial pore pressure. In addition to the formation fractures that may have been generated or re-activated by high injection pressure, poorly cemented casing annuli may have acted as fluid paths between the reservoir and Top Shetland.

This pressure increase can cause considerable difficulties when drilling through the Shetland formation using traditional overbalanced drilling, since the window between pore pressure and fracture pressure can be very narrow. Due to this, both underbalanced drilling and managed pressure drilling has been performed on the Gullfaks field.

9 Background

9.1 Gullfaks C well

On Gullfaks C (GFC), a well had to be plugged due to a continuous pressure build-up in the B-annulus that caused reason to believe that the well barrier envelope was unacceptable [44]. This well had originally been drilled and completed as a producer in 1991. After cementing the 9 5/8" casing, a cement bond log was run and analysis of this showed poor cement bonding along the whole casing, which was confirmed by a USIT (UltraSonic Image Tool) log in 2009.

Since it was planned to section mill above the reservoir, it was desired that the reservoir should be isolated before starting to mill, so that the mud weight could be reduced for milling. The plan was to isolate the reservoir using a new technique, referred to as "punch and squeeze" or "blast and seal". This method involved first perforating the casing at an interval where it is cemented, but the cement of low quality and not considered to form a sufficient pressure seal. After perforating, cement is squeezed through the perforations and into the annulus with bad cement. If this was successful, and the annular pressure was coming from the reservoir, the pressure build-up on surface would stop and mud weight could be reduced prior to milling.

The next step was then to measure the formation pressure in Top Shetland, which represented an uncertainty for the rest of the operation. This was done by running an EZSV (Easy Sliding Valve) packer with perforation guns underneath, punching holes in the casing to establish communication to the formation and then perform a pressure test through the packer. After the pressure had been measured, Top Shetland had to be isolated by establishing two barriers above.

Since the barriers would have to be placed in a section with bad annular cement, it was decided to use the regular method of creating a cross-sectional barrier in these types of sections, section milling. The plan was to first section mill 50 m to remove the casing, and then ream the hole to 17 ½" to expose some fresh formation. A cement plug could then be placed to create a primary barrier against Top Shetland, and this could then be verified by tagging and pressure testing.

However, the section milling operations on the GFC well did not go according to plan. The well lost mud, the string got stuck, they were unable to get good hole cleaning and the formation collapsed into the well. As a result, the barriers had to be placed shallower in the well. It was concluded that section milling is not recommended in this formation, and that the punch and squeeze method successfully isolated pressure.

9.2 Gullfaks A well

In the beginning of 2010, a well on the Gullfaks A (GFA) platform was going to be plugged and abandoned so that the slot could be re-used to drill a sidetrack to a new geological target. This well, hereafter referred to as the GFA well, was originally drilled in 1988 and was completed as a water injector. After drilling the 12 ¼" section, the 9 5/8" casing was run to the correct depth and mud was circulated. During this circulation, the well experienced lost circulation, and spacer and LCM (lost circulation material) was pumped in a failed attempt to cure the losses. Then, cement was pumped downhole and displaced with water followed by mud. Since the well was still experiencing losses, it was attempted to squeeze cement down the 9 5/8" x 13 3/8" annulus. After this, the well started to backflow, which caused an increased wellhead pressure that could not be bled off. It was then decided to squeeze again down the 9 5/8" x 13 3/8" annulus, and after a third squeeze, the well was stable. An FIT was then performed to 1.85 SG, which was enough to drill the final 8 ½" section.

Because of this lost circulation situation, estimating a reliable TOC was not easy without any cement evaluation logs run inside the casing before the liner was run. Since a successful FIT was performed, the annular cement probably did form a hydraulic seal outside the casing. However, this does not say anything about the length of good cement that has been achieved. The well was considered good enough for further drilling and injection, but a sufficient length of good annular cement was needed for permanent P&A. Also, due to the top squeeze that was performed, the 9 5/8" casing was thought to have cement on the outside which could cause problems with pulling during P&A.

After the well was handed over to production, the well was used to inject water and continued to do this for a number of years. Due to a tubing-to-annulus leak, the well was shut-in in 2003. In 2008 the pressure in the B-annulus started to slowly increase. When bleeding off the pressure, the bled off fluid turned out to be oil. This could have indicated that the pressure might have come from the reservoir.

10 Method selection

10.1 Why not use section milling?

After the experiences on GFC, it became evident that an alternative method to section milling would be desirable, since the pressure window is not always wide enough to achieve good enough hole cleaning for milling. Although GFC is equipped with MPD equipment, this should not be used when section milling because of the steel cuttings that are generated. These have sharp edges that may damage rubber sealing elements.

Also, because successful section milling is dependent on the condition of the formation outside casing, it would be useful to have an alternative that was more predictable in unstable formations. Equipment failure causes NPT (non-productive time) which leads to increased time spent on the P&A, and increasing the overall cost of the job. Perforating and squeeze cementing was seen as more reliable with regards to equipment and formation stability than milling, and also had the potential to save time.

Due to the fact that the punch and squeeze performed on GFC was so successful in isolating pressure, Statoil wanted to try to qualify this method as a way to establish a permanent annular barrier in poorly cemented intervals. If this qualification turned out to be successful, punch & squeeze had the potential to partially replace section milling operations.

On the GFA well specifically, simulations were performed to determine the ECD effects of different circulation rates when milling. In the Lista formation, where the permanent barriers would have to be placed, the collapse pressure was set to 1,65 s.g. and the weight of the milling fluid would have been 1,67 s.g.. With the fracture curve showing approximately 1,88 s.g. at 2050 m depth, this would give a maximum circulation rate of 2000 lpm when simulating ECD effects. Based on experiences, the flowrate should generally be higher than 3000 lpm to achieve good hole cleaning, which would give an unacceptably high ECD of almost 1,96 s.g..

10.2 Challenges prior to operations

Since the new well on GFA was planned to be kicked off in the Lista formation, a main challenge was to establish enough meters of good barriers against the reservoir, and potentially against Top Shetland, in the old well section. The reason for wanting to kick off in this formation was due to both the geology and the well path. A lower kick off point would make it difficult to reach the target, while a higher kick off point would give a smaller pressure window.

Also, once the barriers were in place, another challenge was to be able to verify that the cement was actually in place and of good quality.

Another concern was that it would not be possible to squeeze the cement through the perforations and into the annulus. Although injectivity tests were going to be performed, this would not necessarily guarantee success since these tests are performed with mud, which may give a different result than cement injection.

11 Equipment

11.1 Perforations

On the GFA well, two types of perforation guns were used, one type from Schlumberger and one from Halliburton. The Schlumberger guns were tubing conveyed perforation (TCP) guns which were run down on drillpipe and perforated four long intervals, three of them from 55 m to 84 m long and the last being 16 m long.

On the other hand, the Halliburton guns perforated much shorter intervals, 5 m and 10 m. The Halliburton guns were strictly speaking also tubing conveyed, but they were attached to EZSV packer plugs, so that the EZSV and perforation gun assembly could be placed in the well, and the drill string could sting out of and into this assembly.

11.1.1 Guns

Schlumberger used different sizes of HSD (high shot density) guns for the perforations in this well. For the 7” liner, both 4.72” and 4 ½” HSD guns were used with different charges. These guns are both designed for this size of liner, but the 4.72” guns have a higher pressure rating than the 4 ½” guns. In the 9 ⅝” casing, a larger 7” HSD gun was run with various charges. Since the Schlumberger guns were conveyed by drillpipe, it could be possible to attach a long section of spacer joints between the firing head and the guns, so that the shut-down of adjacent wells could be minimized.

On the other hand, the Halliburton guns were attached to EZSVs that were planned to be left in hole, so it would not be practical to have a long section of spacer joints, since these would also be left in the well. Although drillable guns are available with squeeze packers, it was decided to use regular steel guns, since these have a larger range of available charges, higher shot density, are available in longer sections and have better availability. Also, it was not considered likely that it would be necessary to drill out the guns.

11.1.2 Actuation methods

The two different service companies each had their own type of firing head for their perforation system, but the principles were similar.

Halliburton used a firing head called Time-Delayed Firer (TDF), which is pressure-actuated and has a time-delay fuse that allows for a 4-6 minute delay between activation and firing the guns. This time can be used to adjust the pressure from the actuation pressure to the desired pressure during firing. Because of this, the TDF is suitable for both over- and underbalanced perforating. The actuation pressure is adjusted by adjusting the number of shear pins in the firing head. Once the pressure is increased to the maximum actuation pressure, these pins are sheared, forcing a piston into a primer that ignites the delay fuse. As mentioned, this delay fuse burns for a predetermined time between 4 and 6 minutes and finally detonates the perforating assembly.

The Schlumberger firing head is called a Hydraulic Delay Firing (HDF) head, and is also pressure-operated and time-delayed. Although the mechanics are somewhat different to the Halliburton firing head, the basic functions are more or less the same.

11.1.3 Choice of hole sizes

There were several different hole sizes used on the different perforation runs in the GFA well, as showed in Figure 5. These are generally divided into two types: big hole and deep penetrating. Big hole charges create a hole with a relatively large diameter, but a shallow impact. On the other hand, deep penetrating charges give a small diameter hole with a deep impact.

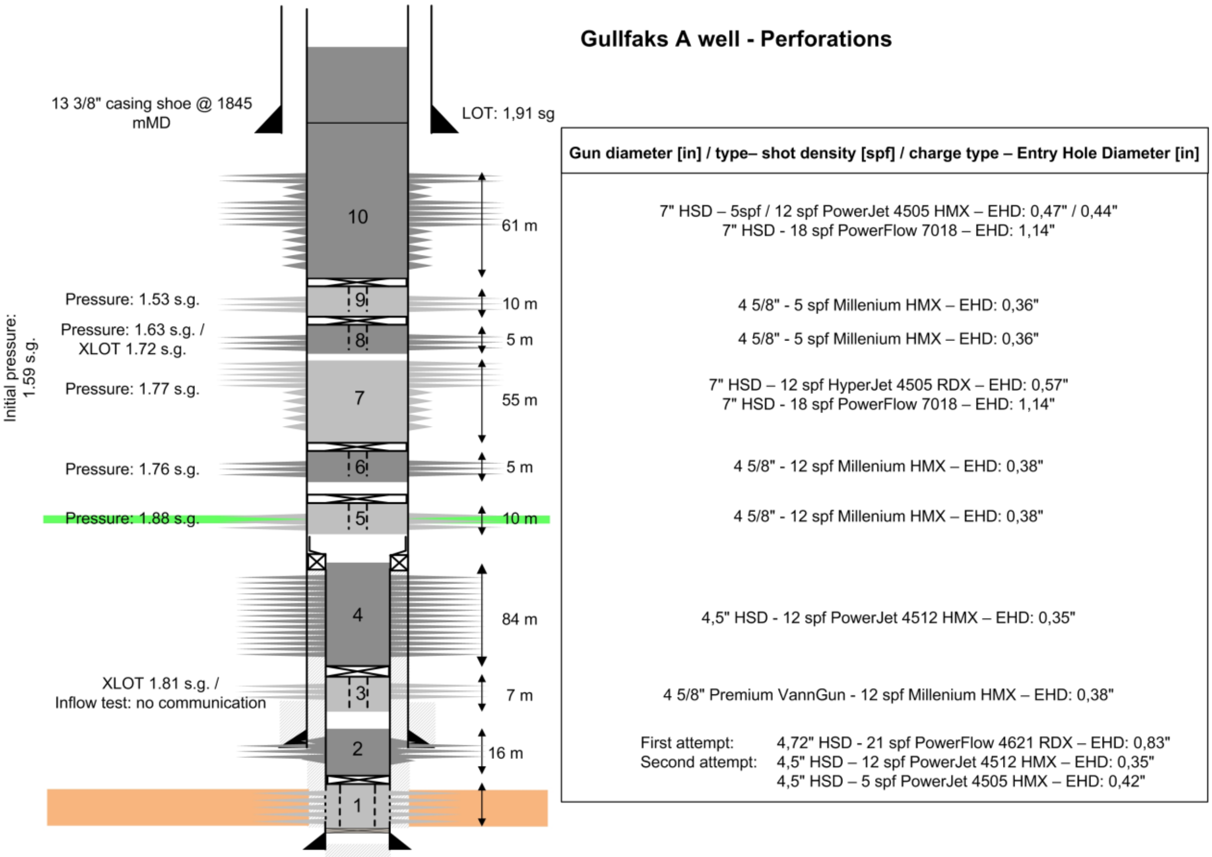

Figure 5 - Overview over perforation charges and guns

Starting from the bottom, the first perforation interval the casing was done with a high shot density of 21 spf (shots per foot) and big hole charges, with the idea that as much as possible of the casing should be removed to get a large volume of cement into the annulus. However, the cement squeeze through these perforations was unsuccessful, so the perforation interval had to be re-perforated after drilling out the cement. The reason for not being able to squeeze could be a combination of two factors: that the big hole charges were not able to penetrate the cement layer properly, and that the time used between mixing and pumping cement was too long, so that the cement started to gel up. With the high pressure that was applied during the squeeze, the formation should have fractured, however there was no indication of this, indicating that there was no communication between bottom hole and formation. On the other hand, the injectivity test showed that there was at least some communication before the cement job. Therefore, deep penetrating charges at were used at the second attempt with a shot density of 5 and 12 spf.

In the liner lap, the charges would have to perforate both the 7” liner and the 9 5/8” casing. Due to this, deep penetrating charges were used in both the perforation jobs in the liner lap.

Deep penetrating charges were also used for all the EZSV perforation intervals.

The last perforation interval had a somewhat different shot configuration compared to the other intervals. Since one of the objectives in this well was to try to qualify the punch & squeeze method, the last 60 m perforated interval would be squeeze cemented, drilled out, logged and then cemented again. Hopefully this would give an indication of whether or not the method had succeeded in establishing a good annular barrier. Because of this, the 60 m interval was divided into 3:

- One section with deep penetrating charges
- One with big hole charges
- One with a mix of big hole and deep penetrating.

The idea was that this could then be used to optimize the method by looking at which interval gave best results on the logs.

11.1.4 Safety aspects

Since perforation guns contain explosives, there are certain safety aspects that have to be addressed when using these types of tools. This also applies when handling the guns out on the pipe deck, where they should be placed in a dedicated area where lifting operations directly above the perforation guns should be limited.

The TCP guns are not armed before the firing head is installed on top of the guns, so when the firing head is made up to the rest of the string, extra precautions should be taken. The area below the rig floor should at this point be barriered off so that no personnel is present until the guns are 100 m below the wellhead, according to APOS requirements for fixed installations. In addition to this, wells in a 3 m radius need to be shut off from the firing head is attached and until the guns are 100 m below the sea floor. In the GFA well, that meant closing down 5 wells, one of which was a high rate producer. Shutting in these wells delays production and may cause a considerable loss of income. Also, shutting in wells introduces a risk of getting problems with starting them up again.

The pressure generated by the perforation charges may lead to trapped pressure between connections, so precautions should therefore be made to vent this pressure in a safe manner. Finally, the shear ram in the BOP should never be closed on perforation guns.

11.2 Logging

There are several ways to evaluate cement jobs. TOC can be found using a temperature log, since cement gives off heat while it sets up [28]. However, if the bond and integrity of the cement needs to be evaluated, there are generally two main types of evaluation tools that are used [45]. These two are the standard sonic Cement Bond Logs (CBL) and the newer UltraSonic Image Tools (USIT).

11.2.1 CBL

Cement Bond Logs indicates if the bond between cement and casing is good or not by using a sonic logging tool [1, 46]. This tool consists of a transducer that transmits low frequency sonic pulses that travel along various paths through the borehole fluid, casing, cement and formation along the wellbore and end up at two receivers that are placed 3 ft and 5 ft below the transmitter [45]. The data that is recorded is the amplitude of the first peak of the wave received at 3 ft, marked as E1 in Figure 6, and the full wave received at 5 ft. If the casing is bonded to cement or another rigid material, the vibrations will be dampened and the amplitude of E1 is small compared to the amplitude in a free casing section.

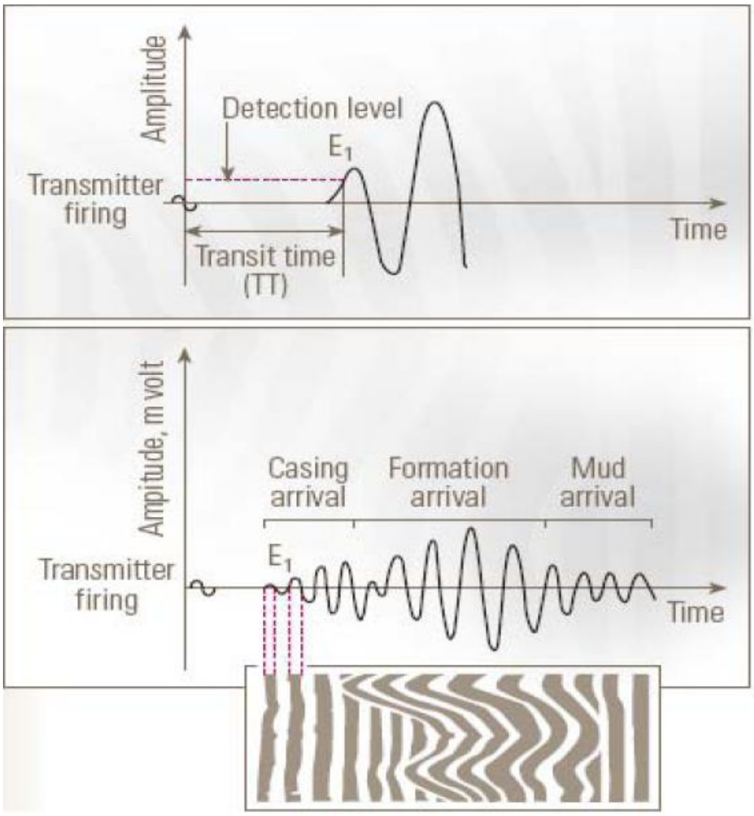

Figure 6 - An illustration of the arrivals at the 3 ft and 5 ft receivers. The pattern at the bottom is an example of a VDL. [1]

The waveform from the 5 ft receiver is displayed on what is called a VDL, and can be used to evaluate both the casing-cement bond and the cement-formation bond [1, 45]. If the traces are strait and parallel, this can indicate that the casing arrivals are strong, and that the casing is free with no cement in the borehole. However, if there are variations in the waveform, this indicates that at least some cement is present. To differentiate between channelling in the cement and a micro-annulus, pressure can be increased and the log re-run.

11.2.2 USIT

An UltraSonic Imager tool is an acoustic borehole measuring device that can be used for cement evaluation with 360 degrees coverage of the well [47]. Analysing the USIT results gives information about the acoustic impedance of the materials which are in contact with both sides of the casing. These results are presented in image logs that provide a visual presentation of cement quality.

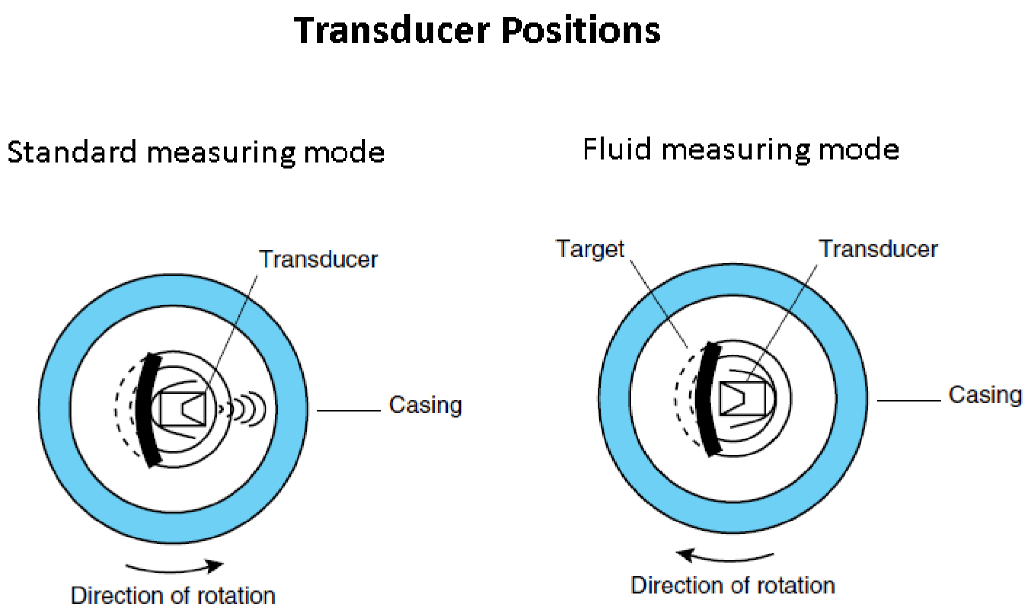

Figure 7 - USIT measuring modes [47]

The tool itself includes a rotating subassembly with a transducer that can be rotated in both directions, as seen in Figure 7 [47]. Clockwise rotation causes the transducer to turn within the subassembly so that it faces a reflection plate with known thickness and elastic properties [1]. In this position, the transducer can measure downhole fluid properties that are used for later reference. When the subassembly is rotated counter-clockwise, the tool is in standard measuring mode with the transducer facing the casing.

Acting as both a transmitter and a receiver, the transducer sends out an ultrasonic pulse with a frequency that is determined by the casing thickness and fluid properties, the transducer then switches to receive mode, and the reflected pulse or echo is received by the same transducer [47]. When the pulse leaves the transducer, it first travels through the wellbore fluid before it strikes the casing wall. At this point, most of the pulse energy is reflected back to the transducer. The rest of the energy continues into the casing and when the pulse hits the casing/annulus interface, the same process is repeated, with some of the energy being reflected and the rest transmitted. The fraction of energy that is transmitted and reflected depends on the difference in acoustic impedances across the interface.

Since the acoustic impedance of the casing and well fluid is virtually constant, the reflected signal decreases at a rate that depends on the acoustic impedance of the material outside the casing [47]. This also means that the accuracy in determining the well fluid acoustic impedance influences the accuracy of the estimated acoustic impedance of the material behind the casing [1]. When the transducer operates as a receiver, it first detects a high amplitude signal from the first reflection, and then a weaker and weaker signal with a peak-to-peak time that is equal to the time that the signal travels back and forth in the casing.

When scanning the casing, the tool provides 36 or 72 measurements at each depth, depending on whether resolution is 5 or 10 degrees. These measurements can be processed to find the internal casing radius, thickness and inner wall smoothness as well as the acoustic impedance of the material behind the casing [1].

11.2.3 Log interpretation

Cement evaluation logs are often gathered from a tool string consisting of a casing collar locator, gamma ray tool and inclinometer tool in addition to the cement bond log tool and USIT [48]. While the two first tools are used for correlating the logs to casing tallies and open hole logs, the inclinometer tool measures the orientation of the tool using three accelerometers, which is used to orient the USIT image log.

When the tool is run into the well, the USIT is rotated so that the transducer faces inward to measure fluid properties [48]. As mentioned, there is a measure plate of known thickness at a known distance from the transducer, so that the acoustic impedance and fluid velocity of the well fluid can be determined on the trip into the well. The theoretical maximum and minimum impedance of the well fluid is indicated by two lines on an impedance vs. depth chart, and the measured values should plot somewhere between these two. Fluid velocity is plotted versus depth, and this should show a linear constant fluid velocity.

The final log can be divided into three parts: quality control on the left side, casing evaluation in the middle and cement evaluation on the right side, as seen in Figure 8 [48].

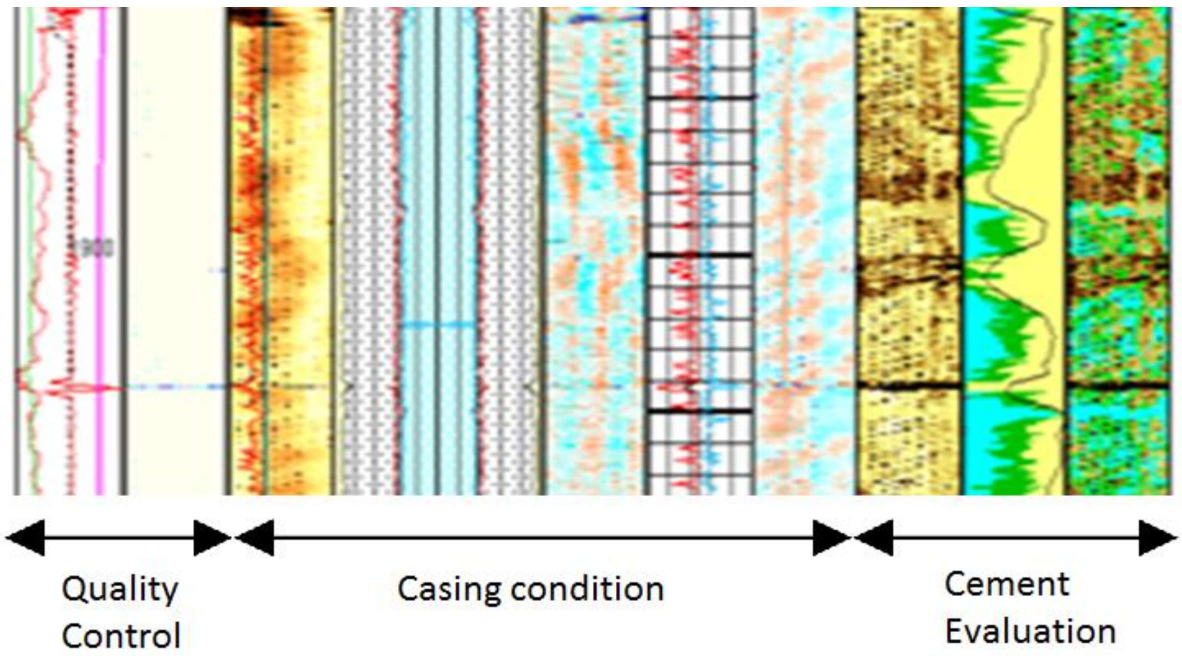

Figure 8 - Three parts of the USIT log

The middle part of the log gives an overview of the condition of the casing. The light blue part with red and blue lines on each side gives a cross-section of the casing, indicating the minimum (blue), maximum (red) and average internal radius. These curves are repeated on both sides from the centre, so that a cross-section is given.

Finally, the cement evaluation part of the log is on the right side, as shown in Figure 9. This consists of three plots: the raw acoustic impedance, a cumulative bond plot and an azimuthal bond plot [48]. First, the raw acoustic impedance plot shows light and dark areas, where the dark areas have good bond to pipe. The cumulative bond plot shows the percentage of:

- bond to pipe (shown as yellow),
- fluid (shown as blue), gas (shown as red) and
- microdebonding (shown as green).

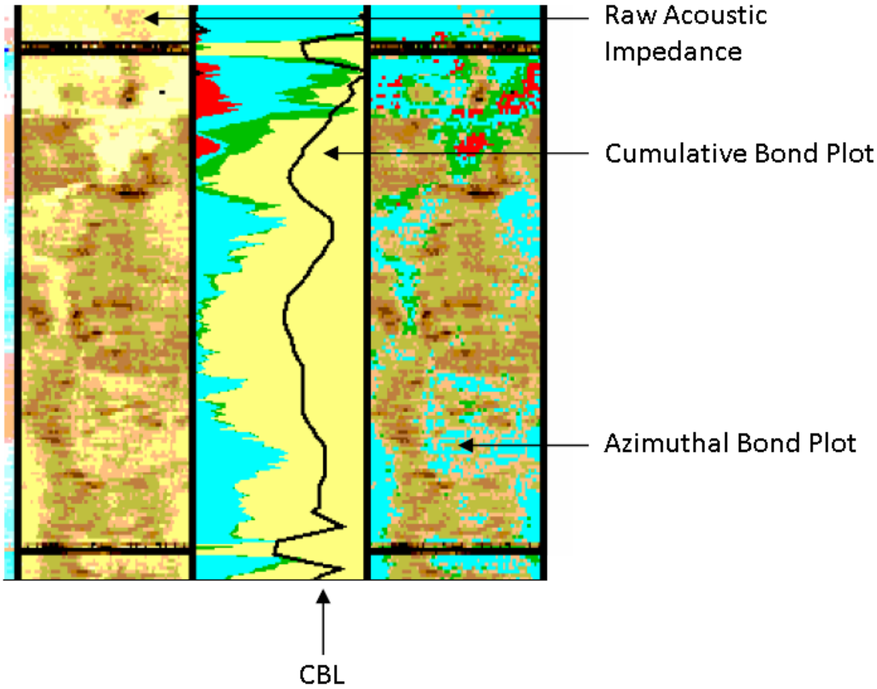

Figure 9 - Cement evaluation part of USIT log [48]

The microdebonding reading has larger uncertainty that the others. In addition to the cumulative plot from the USIT, the reading from the CBL is included as a black curve. The azimuthal bond plot is an image of the wellbore and indicates which areas have good and bad bonding. As with most image logs run in combination with an inclinometer tool, the sides of the image are up and the centre of the image is down. The colour categories are the same as with the cumulative bond plot.

11.3 Packers

For the cement job requiring a retainer, Halliburton EZ Drill SVB squeeze packers (EZSV-B) were used. EZ Drill is a name that Halliburton uses to identify tools that are drillable, and SVB indicates that the packer contains a sliding valve and has a brass mandrel. The brass mandrel is stronger and more ductile than the cast-iron mandrels found in regular EZSVs, meaning that the packer can withstand greater mechanical loads and internal pressures. Although it is stronger than regular EZSVs, it is still drillable.

The Peak VMB plug is a retrievable, gas tight plug that can be set multiple times and has a ball valve that can be opened and closed as required. It can therefore be used for pressure tests and inflow tests.

12 The Punch & Squeeze (Blast & Seal) Method

12.1 Squeeze cementing – two techniques

In the GFA well, there were basically two techniques that were used to set cross-sectional cement plugs. The first technique was the same that was used on the previous well on GFC, however since this method gave only short plugs; a new second method was also tried on the GFA well.

12.1.1 EZSV with TCP-guns

On GFC, a configuration consisting of an EZSV packer with guns mounted underneath was used to perforate the casing. After the packer is set and the casing has been perforated, the drillstring can sting in and out of the packer to perform an inflow test or circulate as required. After this, the string can be stung into the packer and spacer and cement can be pumped through a port in the EZSV and into the perforations.

12.1.2 TCP and balanced plug

Since the squeezed cement plugs were planned used as barrier plugs in the GFA well, a method of placing longer cement plugs was developed. This method consisted of first perforating with TCP guns on a separate trip, then setting a balanced cement plug over the perforated interval plus a calculated height for extra volume and finally squeezing this plug into the perforations.

12.2 Pipe cleaning

On the GFA well, a total of 13 cement plugs were set during the whole P&A operation. When setting such a large number of cement plugs, it is important that the drillpipe is properly cleaned to avoid cement setting up inside the pipe. If cement sets in the drillpipe connections, this can cause problems during later drilling, since loose hardened cement pieces may cause problems with sensitive MWD tools. To avoid this, several measures were taken on GFA to assure good pipe cleaning.

12.2.1 Wiper darts / sponge balls

To clean the inside of the drillpipe, a wiper dart or a sponge ball can be used. A wiper dart is a rubber dart that is loaded into the drillpipe and pumped through the pipe to wipe cement off the inside of the pipe walls. These darts are available in combination sizes if different sizes of string are used. Since these darts are slightly more than full diameter, it is important that there are no restrictions in the string that could cause the dart to get stuck.

Sponge balls are flexible balls that are made of a porous rubber material. These work in much the same way as wiper darts to clean the drillpipe.

12.2.2 Nut Plug

The Nut Plug material is basically ground nutshells from walnuts or pecan nuts, of which walnut shells are strongest. Nut plug is often used as a LCM since it is available in different grain sizes and has a high compressive strength. However, it may also be used to improve cleaning inside the drillpipe since the solids have an erosive effect on cement with their sharp edges. When used for this purpose, it is pumped after the wiper dart to remove the remaining cement that the dart did not get rid of. Also, Nut Plug is chemically inert and compatible with all types of fluid and can be disposed as normal waste onshore if used with WBM (water based mud). However, it is necessary to have large-sized screens available for the shaker to handle the Nut Plug material [49].

12.2.3 VAM EIS

Normal drillpipe connections have a small space between the joints of pipe that will inevitably be filled up with cement during a cement job. These small spaces are not easily accessed by the wiper darts, sponge balls or Nut Plug and can therefore be a problem when trying to clean the pipe. Nevertheless, there are available drillpipe connections that do not have such large cavities, but are smoother and easier for wiper darts or sponge balls to clean. VAM EIS is such a connection and is fully compatible with API connections. This connection also allows for higher torque capacity with the same diameters as regular connections or a larger ID (inner diameter)/smaller OD (outer diameter) with the same strength.

12.3 Inflow testing

Because of the pressure uncertainty in Top Shetland, it was necessary to measure the pressure in both the GFC and the GFA well. In the GFA well, it was also planned for two additional inflow tests to verify that the squeeze jobs formed an effective pressure seal. These three tests were all planned as inflow tests using an EZSV. The inflow tests use the weight of the fluid column above the point of inflow to determine the flowing pressure of that point.

When running the packers in hole, the well is filled with mud so that there is overpressure in the well. After the packer is set and the casing is perforated, the drillstring is stung out of the EZSV and a calculated volume of light fluid, such as fresh water, is pumped into the drillstring while choking returns, so that bottom hole pressure remains the same. When stinging into the EZSV again, the perforated interval is now exposed to the pressure given by the height and weight of mud and fresh water plus the stand pipe pressure measured on surface. The overbalance is then bled off in predetermined steps from the drillpipe while noting the stabilized pressure at each step. As the overpressure decreases, the stand pipe pressure should decrease for each step until equilibrium is reached between bottom hole pressure and formation pressure. When formation pressure becomes higher than the well pressure, the stand pipe pressure will increase due to formation fluid entering the drillpipe. The pore pressure can then be determined by adding the hydrostatic column to the minimum stand pipe pressure.

Because of the new Statoil requirement to use the minimum formation strength instead of fracture pressure, there are currently a lot of XLOTs being conducted on Statoil's wells, even in old fields like Gullfaks. In the GFA well, three XLOTs were performed, one of which did not give conclusive results because of the high mud weight used. Since several cubic meters of mud are pumped during the XLOT, the inflow tests should be performed before the XLOTs to avoid having to bleed back the mud first.

12.4 Overview of the Gullfaks A well P&A

An overview of the final result of the P&A of the Gullfaks A well is given in Figure 10, and the plug numbers in the text correspond with the numbers on the figure.

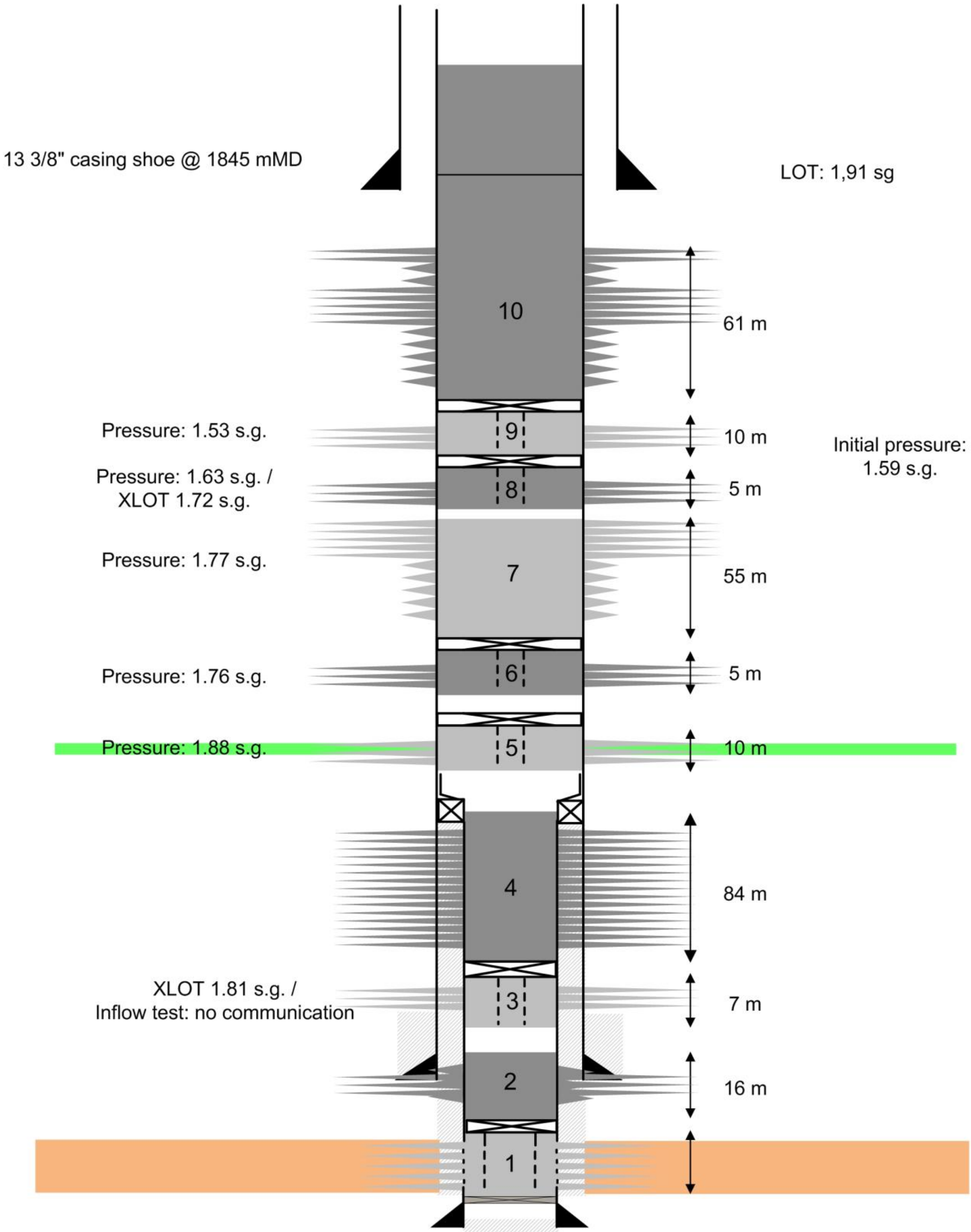

Figure 10 - An overview of the Gullfaks A well after P&A

The first part of the P&A was done before the rig was skidded over the well. A tubing puncher was run in on wireline to punch holes that would provide communication between tubing and annulus. Kill fluid was then circulated into the tubing with returns from the annulus in order to kill the well. A plug was then set before removing the X-mas tree.

After the well had been killed, the rig was skidded in place and the X-mas tree was replaced by a BOP. When the plug had been retrieved, the tubing was removed. Then, the production packer was milled and retrieved using a packer picker. The well was then cleaned to prepare for the rest of the P&A.

12.4.1 Plug #1

The first cement plug was squeezed through an EZSV packer placed above the gravel pack assembly and into the gravel pack and perforations. Ideally, this would lead to some of the cement flowing upwards to seal off the reservoir from the zones above.

12.4.2 Plug #2

A Schlumberger TCP assembly was then run to perforate a 16 m interval with big hole perforations below the 9 5/8" casing shoe. Cement was then placed as a balanced plug on top of the previously set EZSV and it was attempted to squeeze the cement into the perforations by closing the annular and pumping through the drill string. Even though pressure was increased to the maximum acceptable pressure, above the fracture pressure of the formation, the cement could not be squeezed. When pressure was bled off, the volume of returned fluid was close to the same as volume injected, confirming that the squeeze had been unsuccessful.

After evaluating the experiences with the unsuccessful squeeze, it was found that the time used between mixing the cement and starting the squeeze was too long compared to the thickening time for the cement used. Therefore, extra effort was made to reduce the time used after mixing and the thickening time for the cement was also increased for the next attempt. It was also though that the big hole shots might not have properly penetrated the cement layer, allowing mud to be injected, but not cement. The cement plug was drilled out and the same interval was perforated again, this time with deep penetrating charges. A new balanced cement plug was placed, and this time the squeeze was successful. The soft, contaminated top of the cement plug was then drilled out until solid cement was encountered, and a certain amount of weight was applied to confirm the location and mechanical strength of the plug.

12.4.3 Plug #3

The next cement plug was placed using an EZSV packer with perforation guns attached. After the EZSV had been set at the correct depth, the guns were fired to achieve communication with the formation through the casing. An XLOT and inflow test could then be performed to evaluate formation strength and flow potential of the formation.

Since the well was thought to be leaking along the outside of the casing from the reservoir, the inflow test was performed in two stages. The first step was to decrease the pressure to 30 bar below initial Top Shetland pressure, to check if there was communication between

Top Shetland and the perforations at this depth. If communication had been achieved, this would indicate that the casing cement above the perforations did not seal along the casing and that Top Shetland had flow potential. The pressure was kept at 30 bar below initial Top Shetland pressure for several hours, and indicated no communication with Top Shetland.

The second stage of the inflow test was to further decrease the pressure to 50 bar below the measured reservoir pressure. The purpose of this step was to check if there was communication between the perforations and the reservoir. If the previous squeeze job had been successful, the cement should have formed a seal above the reservoir, so a bad inflow test would have indicated that the previous squeeze job was unsuccessful. However, the pressure remained stable, indicating no communication with the reservoir either.

Since it was thought that the B-annulus leak was coming from the reservoir and went along the casing, these tests were still in line with the assumption that the probability of high pressure in Top Shetland was low.

12.4.4 Plug #4

The fourth plug was the longest of all the cement plugs in this well at 84 m. Its main purpose was to establish a large enough length of barrier to comply with APOS and NORSOK D-010 for permanently isolating the reservoir section. Like plug #2, TCP guns were used to perforate the well before setting a balanced plug and squeezing this into the perforations. Since this was in the liner lap, deep penetrating charges were used to make sure that both the 7” liner and the 9 5/8” casing were perforated. This plug was also the last plug in the 7” section, the rest of the plugs were set in 9 5/8” casing.

After the plug had been placed and verified, a USIT log run was performed in the 9 5/8” casing to get an idea of how the cement in the annulus looked before the punch and squeeze operations were performed.

12.4.5 Plug #5 – Measuring pressure in Top Shetland

The next step was then to measure the pressure in the Top Shetland formation. From the start, this was recognized as the single most critical uncertainty in the well. Although the probability of high pressure was considered to be low, the operational consequences were substantial. A pressure of more than 1,75 s.g. would mean that it would not be possible to drill the new sidetrack with conventional drilling methods. The pressure was measured with an inflow test using an EZSV in the same way as the previous inflow tests.

This inflow test showed a stable pressure that was equivalent to 1,88 s.g., much higher than the maximum required for drilling the planned sidetrack, and the highest pressure measured in Top Shetland on the Gullfaks field. The drill string was then pulled out of the EZSV and mud weight was increased from 1,68 s.g. to 1,90 s.g. before filling the string with spacer and cement and then stinging into the EZSV again. The fifth cement plug was then placed through the EZSV and into the perforations.

12.4.6 Plug #6 – Isolating Top Shetland

At this point, the plans for the new sidetrack had to be put aside and the operation changed from being a slot recovery to being a pure P&A. First, the high pressure zone had to be isolated. It was decided to continue with the planned cement plugs to try to isolate the pressure before placing additional plugs to achieve a sufficient length of barriers.

A 5 m long interval was perforated using EZSV-conveyed perforation guns before performing an inflow test to measure the pressure. Since the previous cement plug had been squeezed directly into a formation with flow potential and not above, there was no guarantee that a good cement job would isolate pressure, seeing as the fluid could flow around and along the outside of the cement. The inflow test showed a pressure of 1,76 s.g., which was still much higher than the initial pressure at this depth. Cement was then squeezed through the EZSV and into perforations as earlier.

12.4.7 Plug #7

Although planned as a 60 m interval containing three sections with different perforation charges, this interval was slightly altered due to the fact that this was no longer going to be the last cement plug. Instead of dividing the interval into three sections, the interval was perforated with deep penetrating charges in the top section and a big hole charges below this, perforating a total length of 55 m. However, the section was still perforated using TCP guns without an EZSV packer since an inflow test was not initially planned for in this section.

After perforating, losses were observed during circulation, so it was decided to perform a new inflow test to measure the pressure. Seeing as it was still necessary to set a cement plug over the interval, a Peak VMB retrievable plug was placed above the perforations for the inflow test. This plug has a relatively large OD, so a low running speed was required to avoid surge and swab effects when running the VMB plug in and out of the well. The inflow test showed a pressure of 1,77 s.g., which was roughly the same as the previous inflow test, indicating that the high pressure zone might extend some distance into the Lista formation.

A balanced cement plug was then set in the interval as planned, but with some losses experienced while displacing the cement.

12.4.8 Plug #8

From here on, the operations performed were not part of the initial plan, but since the punch and squeeze method had already been implemented so many times in this well, the Gullfaks team were relatively comfortable with continuing to use this method to seal the high pressure zone. Especially when using the EZSVs, the pressure could be measured, XLOTs could be performed and cement could be placed with the reassurance being able to pull out of the EZSV packer and being isolated from the perforations should this be needed.

It was therefore decided to set short cement plugs with EZSVs until the high pressure zone was isolated, i.e. until measured pressure was the same or lower than initial pressure. A new 5 m interval was therefore perforated under an EZSV packer, and an inflow test and XLOT was performed before setting the 8th cement plug. Since the inflow test measured a pressure equivalent to 1,63 s.g., the mud weight was decreased from 1,79 s.g. to 1,65 s.g. The XLOT gave a minimum horizontal stress of 1,72 s.g.

12.4.9 Plug #9

Although the measured pressure was now lower than the previously measured pressure, it was still higher than the initial pore pressure of approximately 1,59 s.g. at this depth. Therefore, a new EZSV cement plug like the previous one was needed. It was attempted to perform an XLOT, but because of the high mud weight, the test was non-conclusive.

The pressure during the inflow test was lowered to 1,53 s.g., indicating that the formation was impermeable, assuming that the initial pore pressure was approximately 1,59 s.g., and the high pressure zone could be considered to be sealed. Therefore, what remained was to set a sufficiently long cement plug that would act as a permanent barrier against the highest source of inflow.

12.4.10 Plug #10

Since high pressure was no longer considered a problem and the main issue was to place a long cement plug, the next cement plug was set as a balanced plug over an interval perforated with TCP guns. A 60 m interval was perforated with three sections using different perforation charges:

- The bottom 20 meters were perforated using big hole charges
- The next 20 meters were perforated using deep penetrating charges
- The top 20 meters were perforated using a mix of big hole and deep penetrating charges.

The reason for this was to see if the type of charges used would influence the result of the squeeze, and which type of holes gave the best cement bond after cementing. Since this interval would be used to try to qualify the punch and squeeze method, it was necessary to verify how good the cement bond was after the squeeze. This was done by logging the interval before perforating, perforating, logging the same interval again, squeezing cement through the perforations, drilling out the cement inside casing and then logging the same interval for a third time.

A summary of the log results is given in chapter 12.6. These did not indicate a good bond along the entire 60 m, but it was decided not to squeeze more cement into the annulus since this could lead to cementing into the 13 3/8” casing shoe. If the inside of the shoe had been cemented, this would probably have sealed off the 9 5/8” x 13 3/8” annulus, and the B-annulus could no longer have been used to monitor pressure under the 13 3/8” casing shoe. Therefore, Statoils well integrity group requested that at least 10 m of the annulus under the 13 3/8” shoe was left uncemented to be able to monitor the long term integrity of the punched and squeezed intervals.

Inside the 9 5/8” casing, a final 200 m long cement plug was set.

12.5 Qualifying the Punch & Squeeze method

Several steps were taken in the GFA well to find out if this method could be qualified for future use. In principle, the punch & squeeze method is simple and could be applied in several types of wells. However, before using the method on wells were section milling was a realistic alternative, it was practical to first test it out on a well where it was not advisable to section mill.

First of all, several inflow tests were performed to check the actual sealing capabilities of the cement plugs at the time of testing. As mentioned, inflow tests do not say anything about the length of sealing cement, the tests only indicate if some kind of seal exists. If the section of sealing cement is very short, even minor damages to the cement could cause a leak through the plug. On the other hand, a long cement section could be damaged in one area, while the rest of the undamaged section remains sealing.

Also, since mud contamination can weaken the cement at the interfaces between mud and cement, a longer interval with cement will have a greater chance of containing good, non-contaminated cement than a short interval. It was therefore important to also verify that the punch and squeeze method could give a certain length of good annular cement.

This was done by drilling out an interval that had been punched and squeezed and then running a USIT log to see if the method had created a layer of good cement between the perforated casing and the formation wall, as described in chapter 12.4. If a good layer had been created, the length and position of good cement could be found from the logs.

However, at the depth that this was done, there was initially no cement outside the casing. This meant that even if good results had been obtained for this section, this did not necessarily mean that punch and squeeze would create a good annular barrier in an annulus that was partly covered with cement or contained damaged cement.

Since the initial plan to sidetrack the well was aborted, it was decided to install a x-mas tree and short length of tubing, so that the well could be monitored and a tubing plug could be set in the event of a re-entry. As such, the well was not permanently abandoned, but the long term integrity of the well could be monitored, so that when the final abandonment takes place, it is easier to make an informed decision about further work.

12.6 Log results

The three USIT log runs were meant to give insight into how well the punch and squeeze method with TCP guns was able to given long sections of annular cement. This was done by logging the area where a TCP cement squeeze was performed before perforation, after perforation and after squeeze cementing. The first log run was performed after the plugs in the 7” liner had been set, and before the 9 5/8” casing above the liner hanger had been perforated. This run covered the whole 9 5/8” casing from the liner hanger to surface, and was meant to give a baseline that the other logs could be compared to.

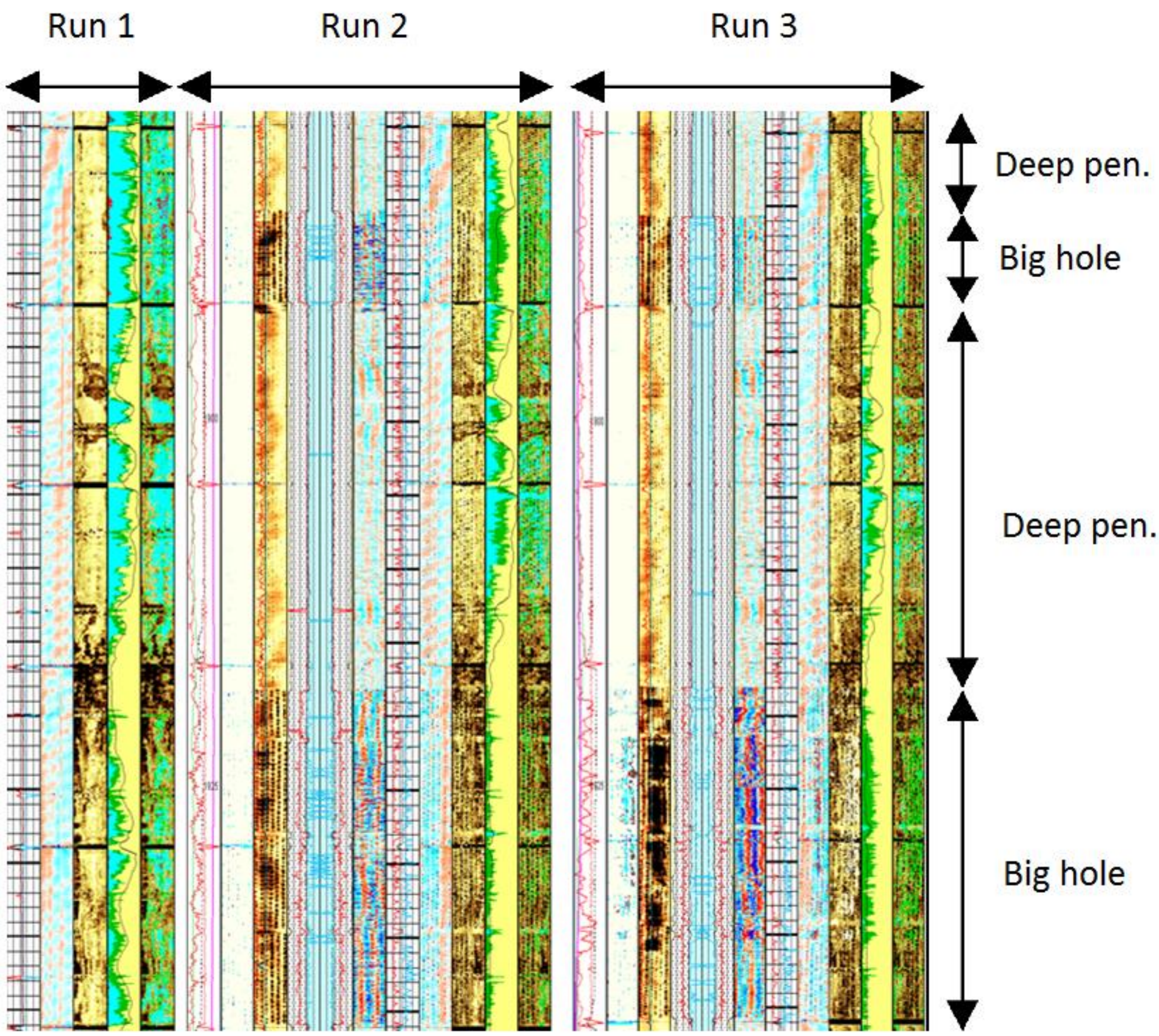

Figure 11 - USIT log results

"Run 1" in Figure 11 shows the part of the log that covered the intervals that was later perforated. As we can see, there is a lot of liquid in the annulus, indicated by the blue colour on the USIT logs, but there are also some patches of cement present, indicated by the dark areas. It may be worth noting that there is an interval that seems to be isolating, with a very dark area on the USIT log and almost no indication of liquid or gas.

The second run was carried out after several cement squeezes had been performed in the 9 5/8" casing. At this point, 60 m of casing had been perforated prior to the last squeeze operation when the USIT was run. These perforations can be observed in the casing cross section, where the red line is the maximum radius, the blue line is minimum radius and the black line is maximum radius. We can see that the areas perforated with big hole charges have a larger maximum casing radius than the sections perforated with deep penetrating charges. This could indicate that the big hole charges deform the casing more than the deep penetrating charges, which may seem reasonable.

On the USIT log, we can see that below the zone that appears isolating there is a section that seems to have good cement outside, even though the section was initially poorly cemented, and the balanced plug that was meant to be squeezed through the perforations had not yet been set. This indicated that cement from the previous squeeze had been displaced upwards in the annulus outside the casing. The previous squeeze, cement plug nr 9, was performed through an EZSV with guns that was placed a short length above cement plug nr 8. This could suggest that the plug nr 9 squeeze had a cement foundation in the annulus, and this could be why it flowed upwards.

Also, the second log run illustrates the effect that perforations have on the USIT log, with small, dark spots in the deep penetration intervals and larger dark spots in the big hole intervals.

After the second log run, a balanced cement plug was placed over the perforated interval and squeezed. The cement plug was then drilled out before a third log run was performed over the same perforated interval. This log showed some improvement in the upper half of the perforated interval, but not enough to be considered sealing. The lower half could actually be interpreted as being slightly worse than before the last squeeze; however the green colour that indicates microdebonding is less certain than the liquid and gas readings. There are also a number of processing flags in this interval, perhaps because the cement in the big hole perforations may give readings that the tool is not expecting.

All in all, the logging experts concluded that approximately 30 m of the perforated interval could be considered to be sealing, while the remaining 30 m was considered non-sealing.

13 Alternative methods

13.1 ThermaSet

ThermaSet is a resin that sets when it is exposed to a predetermined temperature for a certain amount of time. In its liquid form, ThermaSet can be easily pumped and can also be injected into small openings such as control lines since it contains no particles in its neat form. However, particles can be used to regulate the density from 0.65 s.g. to 1.8 s.g. Also, ThermaSet has advantages compared to cement when it comes to mechanical strength. While having a high compressive strength like cement, ThermaSet also has a relatively high tensile strength, more that 50 times higher than cement. The flexural strength and rupture elongation of ThermaSet makes it better suited to varying loads than cement. These varying loads could be caused by pressure and temperature cycles that cause the casing to expand and contract, exerting a force on the annulus material.

13.2 Sandaband

In 1999, NPD (the Norwegian Petroleum Directorate) encouraged the industry to develop improved P&A techniques due to a growing concern for the number of abandoned wells on the NCS that were observed to be leaking [50]. Although cement has long been the standard material for permanently plugging wells, it does have a few shortcomings. Compared to the desired properties of a permanent well barrier element described in NORSOK, cement does not fulfil two properties; it is neither non-shrinking nor ductile. As a result of this, a new ductile plugging material called Sandaband was developed.

The idea was based on the fact that poorly sorted sand has low permeability, and that a certain particle distribution can form a sand slurry with high solids content that is possible to pump [50]. Hence, a low permeability material could be placed in the well that does not require a chemical reaction to develop hydraulic sealing properties. Sandaband consists of 70% to 80% quartz solids with a grain size diameter varying from less than a micron to a couple of millimetres. The rest of the volume consists of water and chemicals that make the material pumpable. Since quartz and water are chemically stable, these will not degrade over time or react with other fluids except concentrated hydrofluoric acid. On the other hand, the additional chemicals will be exhausted with time, but since these chemicals are only used to make the material pumpable, this does not affect the sealing capabilities of Sandaband. This has been demonstrated by testing Sandaband prepared without chemicals, and the results showed that this mix had the same gas tightness as Sandaband prepared with the chemicals.

As opposed to cement, Sandaband does not set up following a chemical reaction. Instead, Sandaband has the rheology of a Bingham Plastic material [50]. Bingham Plastic fluids are characterized by the fact that they need a certain minimum shear stress to start flowing, but have a linear relationship between shear stress and shear strain, see Figure 12 [51]. This process is not time-dependant, meaning that the slurry will rapidly form a rigid body when pumping is stopped, without having to wait like cement. Also, if the well experiences dynamic loads that cause stresses in the material, it will simply deform and conform to the surroundings instead of fracturing like a brittle material would.

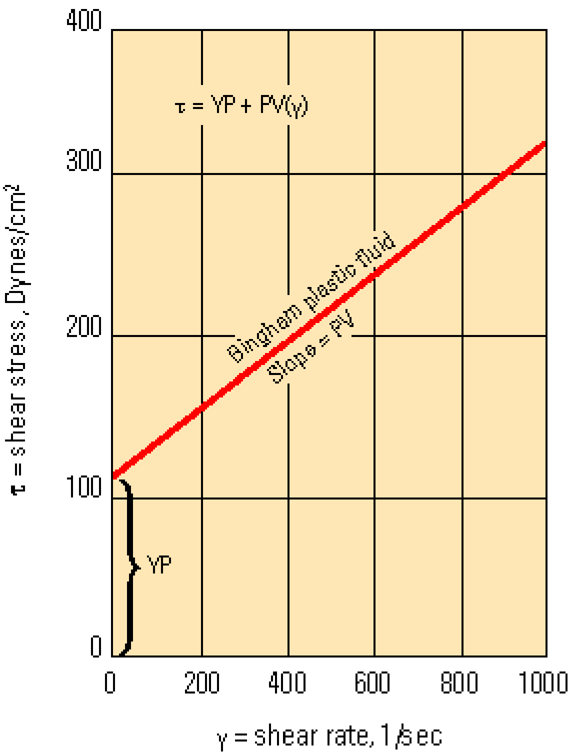

Figure 12 - Typical behaviour of a Bingham plastic fluid. After a minimum shear stress (yield point) is exceeded, the shear rate and shear stress have a linear relationship. [51]

There are two factors that influence how much pressure a Sandaband plug can control. First of all, the height of the plug gives a hydrostatic contribution with a density of 2.0-2.3 g/cc [50]. Secondly; the yield point of the Bingham Plastic material gives a pressure seal that is dependant on the contact area between the plug and the borehole wall. This can be compared to friction in that it works in the opposite direction of the experienced force, preventing the plug from moving until the yield stress is exceeded.

Although NORSOK D-010 does not specify Sandaband or other cement alternatives individually, it does open for using alternative materials as long as these go through a qualification process and an overview of relevant well barrier element acceptance criteria (WBEAC) is made [16]. During the last few years, Sandaband Well Plugging has performed various tests in cooperation with the industry and research institutions in order to qualify Sandaband as a gas tight plugging material. Also, a third-party report was made by Proffshore to verify that Sandaband fulfils the material requirements for permanent plugging in NORSOK [52]. This report concluded positively on Sandabands compliance as a permanent WBE, but underlined the need for a sufficient height and length to control required pressure. Since cement can set up to form a solid plug, the hydraulic sealing properties are not as dependant on height and length as Sandaband, meaning that a longer plug may be necessary if Sandaband is used compared to cement.

Another difference between cement and Sandaband is how its placement can be verified. Once a cement plug has hardened, its location can be confirmed by applying weight to the top of the plug, but since Sandaband does not solidify, an alternative method is necessary. The method used is to run pipe slightly into the plug, and circulate bottoms up from below the calculated theoretical top of Sandaband. If sand is observed over the shakers, this indicates that Sandaband is present at the given depth.

However, if the material is placed in the annulus, neither Sandaband nor other materials can be verified using the mentioned techniques. As discussed earlier, cement can be evaluated using cement evaluation tools, and Sandaband in an annulus may also be evaluated using logging tools, although not necessarily the same types of tools as for cement. While several tools may be used, the preferred method of logging Sandaband is using a pulsed neutron tool. These contain a high-energy neutron generator that emits neutrons that are bombarded onto the formation [51]. The different nuclei in the formation then interact with the incoming neutrons and start radiating gamma rays. Analysis of the energy spectra can separate between different elements, such as the silicon which is abundant in quartz. Since quartz is the main component in Sandaband, its presence can then be identified.

Other methods of verification, like pressure testing and observing operational parameters, are done in much the same way as with cement. As long as the design parameters for the plug are not exceeded, pressure testing and inflow testing can be performed straight after the plug has been placed, since there is no curing time involved.

13.3 Settled barite

During the P&A of wells on the West Ekofisk and Edda platforms, ConocoPhillips used barite that had settled out from drilling fluid as an annular barrier [53]. The idea is that the drilling fluid that is left behind the casing after primary cementing experiences more or less static conditions over a long period of time, causing the barite weight material to settle and form a layer of barite above the casing cement.

When trying to cut and pull a casing string during a P&A, problems had occurred with pulling resistance in a section with no cement [53]. It was found that this could be caused by settled barite from the WBM that had been used during primary cementing. Since the amount of particles in the drilling fluid was known, the assumed height of settled barite could be calculated.

The sealing abilities of the settled barite was verified by setting a bridge plug inside the casing, cutting the casing above the plug, and then pressure testing the exposed barite to 70 bar above the fracture gradient of the formation [53].

It was experienced that a number of conditions had to be satisfied before settled barite could be used as a barrier element [53]:

- During the drilling phase, the well should have been drilled using WBM
- After completion, the well should have experienced closed, static conditions over many years with no history of annulus pressure build up
- The well should be relatively vertical.

ConocoPhillips are satisfied with using settled barite as a permanent barrier element, and have qualified it for this purpose [53].

13.4 NCA CT tool – alternative to section milling

NCA (Norse Cutting and Abandonment) provide a range of tools and services related to abandonment of wells and offshore facilities. One new tool that could prove to be useful in repairing bad annular cement is their Casing Removal Tool. This is a coiled tubing based tool that uses water cutting, high pressure water with an abrasive material, to cut away the casing. The tool consists of an anchor, a stroking tool and an orienting tool that control the cutting nozzle or nozzles so that the cemented casing can be cut into pieces of a desired size. These pieces can be flushed off the wall and left at the bottom of the hole without needing to circulate them to surface. This is an advantage compared to normal section milling, where swarf transport is a considerable challenge.

14 Discussion

14.1 EZSV vs TCP

In the GFA well, the two methods of punch and squeeze were both used several times. The main idea behind using the EZSVs with guns was that this method could be used to isolate high pressure, perform inflow tests to verify the previous squeezes and to measure pressure in Top Shetland. On the other hand, the sections perforated with TCP guns were meant to establish long sections of good cement, so that the well could comply with length requirements for cement barriers.

First of all, the logs showed that the EZSV method of punch and squeeze was able to give at least 20 m of good annular cement. In this cement plug, nr 9 from bottom, the cement seems to have flowed upwards along the outside of the casing to form a section of well bonded annular cement above the EZSV. Since another EZSV squeeze had previously been performed only a short distance underneath plug nr 9, it can be assumed that there may have been some kind of solid foundation in the annulus that prevented the cement from flowing downwards.

In contrast, the logs from the TCP intervals showed little difference between perforated uncemented casing and perforated casing that had been squeezed with cement. This indicates that the method of setting a balanced plug and squeezing this from above did not give the expected results. The idea was that this method would give a long interval of good cement, but the logs show that this is not the case, indicating that this method may not be an ideal solution.

In all of the EZSV squeezes, approximately 15 m^3 of cement was squeezed into the perforations, meaning that a substantial volume of cement ended up somewhere outside the casing. Especially when considering that the perforation intervals were short, and there was limited space inside the casing, it is a good sign that a large volume could be injected, since this indicates that the cement has taken its way into the annulus.

Although the TCP intervals were longer, only 5-6 m^3 of cement was squeezed into the perforations. This means that there is a smaller volume of cement outside the casing that may be spread over a longer interval, increasing the possibility of contamination and poor cement quality.

During planning, the key advantage of the TCP method was that long sections of cement could be placed. It was thought that the EZSVs were most practical for short intervals where inflow testing or an XLOT was required, while the long intervals should be used where a long barrier was required. However, in light of the logs that were carried out, this should perhaps be reconsidered.

The EZSVs do have a considerable advantage in that they isolate the area below the EZSV packer before perforating. Inflow tests and XLOTs can then be performed through the drillstring, without exposing the casing. If an unexpected high pressure zone is encountered during an inflow test, the drill string can sting out of the EZSV and is then isolated from the high pressure while circulating to a heavier mud. When using TCPs, the whole well is in communication with the formation once the casing is perforated, so unexpected formation pressures could cause problems.

Another advantage of using EZSVs is that there is no need to WOC (wait on cement) since the squeezed zone is isolated from the rest of the well after cementing. The cement hardening is therefore not affected by pressure variations above the packer, so further operations may continue straight away.

However, the EZSV running tool is limited to a certain maximum flow rate, which may be a concern when circulating the pipe clean after cementing. If circulation exceeds the manufacturers' recommendations, certain metal parts may fall off the running tool and leave a fish in the hole. Although this is not desired, it does not necessarily affect the job since the fish is small and the area is going to be cemented anyway.

During the P&A of the GFA well, several wells had to be shut down each time the perforation guns went in and out of the hole, leading to delayed production and the risk of not getting wells started again. When using the TCP guns, it is possible to attach a certain length of spacer between the firing head and guns, so that shutting down wells is avoided. This decreases the safety risk and at the same time reduces the economic costs involved. With EZSVs, it is not practical to have a long section of spacer joints under the EZSV, so shut downs cannot be avoided with current technology.

14.2 Placement

As with all cement jobs, correct placement is important in order to achieve a successful punch and squeeze operation. From the logs, it may seem that the result is dependent on what was in the annulus to start with and which formations were present. As mentioned, we see that cement from the EZSV squeeze in the logs may have been forced upwards due to a restriction in the annulus below. This seems to have given at least 30 m of good cement, but it was not a part of the original plans.

Therefore, the setting depths of future cement plugs could perhaps be based on an initial USIT log run. If intervals are found which are thought to be sealing, the squeezes should be placed appropriately with respect to the sealing zones, so that it can be predicted where the cement will flow.

Also, the formation in the squeezed interval could influence the outcome of a punch and squeeze job. If a permeable or fractured zone is present, there could be a risk of squeezing cement into this zone, as the cement will flow in the path of least resistance. This could lead to a less effective placement of cement in the rest of the annulus. Moreover, the strength of the formation influences which squeeze pressures should be used.

If an EZSV with guns is set at a depth where the USIT log indicates sealing in the annulus below the perforations, the injected cement will hopefully enter the perforations and flow upwards along the casing. A second USIT log could then be run to determine the TOC of the new annular cement.

14.3 Punch and squeeze vs. section milling

Compared to section milling, the punch and squeeze method has the advantage that it can be used in areas with uncertain formation pressure and strength, and does not require a large pressure window to be successful. In such wells, section milling may in some cases not be advisable due to the risk of formation collapse, getting stuck and lost circulation.

In this type of wells, a further developed version of the punch and squeeze method could be a realistic alternative to section milling to achieve good annular cement. As mentioned, the logs have indicated that it is possible to achieve a section of good cement using an EZSV with guns in a well section with patchy, poor quality annular cement initially.

However, the logs also show that the method has its weaknesses, especially when setting a balanced plug that is squeezed. Although the EZSV method is promising, there is still uncertainty involved since the logs that indicate good cement bond are run in a densely perforated area and these perforations impact the log results. In hindsight, it could have been a good idea to run a USIT log directly before perforating the 60 m interval with TCP guns, so that the TOC from the previous squeeze had been known. This would have given a better overview of the situation before the area was perforated. The TCP perforations could then have been adjusted to either perforate a shorter section or to perforate further up in the well.

Since it was not anticipated that the previous cement job would flow upwards, this was not done. Originally, it was only planned to verify the length of cement given by the TCP perforated intervals, and it was more or less a coincidence that the logs ended up confirming that the EZSV squeezes could give a relatively long section of good annular cement.

15 Conclusion

On Gullfaks A, a well with poor annular cement was plugged using a method that was new to Statoil. This method consisted of punching holes in the casing and squeezing cement into the poorly cemented interval. In the Gullfaks A well, this was done using two different approaches:

- Setting a EZSV packer with guns underneath, perforating and then squeezing cement through the EZSV, through the perforations and into the annulus
- Perforating using TCP guns on drillpipe, setting a balanced cement plug over the perforations and then squeezing the plug from above.

The inflow tests showed that punch and squeeze could successfully isolate pressure, but this alone is not enough to qualify cement as a permanent barrier. Annular cement should have a certain length of good bond to casing to qualify as a permanent well barrier element, and therefore cement evaluation tools were run several times to log the length of good cement before, during and after the operation.

These logs showed that the approach of using TCP guns and setting a balanced plug did not give the desired annular seal over a long interval. However, the logs did show that the approach of using an EZSV packer with guns could succeed in giving a length of good annular cement. The logs also indicated that small patches of apparently sealing cement were initially present in the annulus, and that these may affect the outcome of the squeezes.

Therefore, a log should be run before determining the setting depths of the cement squeezes, and the log results should be used to optimize the setting depth of the plugs. These squeezes could be performed with the EZSV and gun setup used in the Gullfaks A well or with other packer and gun setups. It would be interesting to see if a drillable gun and packer could give the same results, since this would allow logging below the packer and could give more flexibility.

However, there are a number of challenges with using drillable guns, and one concern is that they are currently only available with a low shot density, meaning that the flow area through the casing is small. If such a method should be considered, this issue should be addressed along with the potential benefits compared to regular guns.

Ultimately, the ideal case would be to have good primary cement jobs and wells that are initially designed with P&A in mind. Still, if remedial action is needed to place annular cement, punch and squeeze could be an alternative as long as section milling is not recommended and the job is carefully planned with the specific well in mind.

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Appendix A

4.2.4 Well barrier elements acceptance tables

General technical and operational requirements and guidelines relating to WBEs are collated in tables in Clause 15, which shall be applicable for all type of activities and operations. Additional requirements and guidelines or deviations to these general conditions will be further described in the sections to follow.

The methodology for defining the requirements/guidelines for WBEs is:

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.*	

4.2.5 Well control equipment and arrangements

4.2.5.1 General

The well control equipment and arrangement shall be according to NORSOK D-001 and NORSOK D-002.

Arrangement drawings and flow diagrams for well control equipment shall be easily accessible for operators of this equipment, such that it is possible to determine the position of a tubular joint relative to the shear rams/valves at all times. These drawings and flow diagrams should include

- geometrical description (location, size, distances to rig floor, distances between rams, etc.),
- operational limitations (pressure, temperature, type of fluid, flow rates, etc.),
- overview of the fluid circulation system (pump, including choke and kill manifold.

4.2.5.2 Well control equipment arrangement for HTHP wells

The installation shall be equipped with

- a failsafe-open, remotely operated valve in the overboard line,
- a cement line pressure gauge in the choke panel,

Appendix B

9 Sidetracks, suspension and abandonment

9.1 General

This section covers requirements and guidelines pertaining to well integrity during plugging of wells in connection with

- temporary suspension of well activities and operations,
- temporary or permanent abandonment of wells,
- permanent abandonment of a section of a well (side tracking, slot recovery) to construct a new wellbore with a new geological well target.

The purpose of this section is to describe the establishment of well barriers by use of WBEs and additional features required to execute this activity in a safe manner, with focus on isolation of permeable formations/reservoirs/sources of outflow, both from each other in the wellbore, and from surface.

Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same. However, choice of WBEs may be different to account for abandonment time, and ability to re-enter the well, or resume operations after temporary abandonment.

9.2 Well barrier schematics

It is recommended that WBSs are developed as a practical method to demonstrate and illustrate the presence of the defined primary and secondary well barriers in the well, see 4.2. In the table below there are a number of typical scenarios listed, some of which are also attached as illustrations. The table is not comprehensive and schematics for the actual situations during an activity or operation should be made.

Item	Description	Comments	See
1.	Temporary abandonment – Non- perforated well.	Non-completed well.	9.8.1
2.	Temporary abandonment – Perforated well with BOP or production tree removed.	With well completion installed.	9.8.2
3.	Permanent abandonment - Open hole.		9.8.3
4.	Permanent abandonment – Perforated well.		9.8.4
5.	Permanent abandonment - Multibore with slotted liners or sandscreens.	Covers permanent zonal isolation of multiple reservoirs.	9.8.5
6.	Permanent abandonment - Slotted liners in multiple reservoirs.	Applies also to slot recovery/ side tracks, etc.	9.8.6
7.	Suspension - Hang-off/disconnect of mariner riser.	Hang-off drill pipe.	9.8.7

9.3 Well barrier acceptance criteria

9.3.1 Function and type of well barriers

For wells to be permanently abandoned, with several sources of inflow, the usual; one primary and one secondary well barrier, do not suffice. Hence, this subclause covers all well barriers and the functions they are intended to fulfil which may be necessary in abandonment scenarios. These well barriers may, however, not be applicable for wells where continued operations are planned, where the wellhead/ well control equipment is utilised and capable, as a secondary well barrier, to cover any source of inflow in the well. This also means that some terms used in this subclause are only applicable in the context of suspension and abandonment of wells and wellbores.

The following individual or combined well barriers shall be a result of well plugging activities:

Name	Function	Purpose
Primary well barrier.	First well barrier against flow of formation fluids to surface, or to secure a last open hole.	To isolate a potential source of inflow from surface.
Secondary well barrier, reservoir.	Back-up to the primary well barrier.	Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/ or hydrocarbons).
Well barrier between reservoirs.	To isolate reservoirs from each other.	To reduce potential for flow between reservoirs.
Open hole to surface well barrier.	To isolate an open hole from surface, which is exposed whilst plugging the well.	"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.
Secondary well barrier, temporary abandonment.	Second, independent well barrier in connection with drilling and well activities.	To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.

The functions of a well barrier and a plug can be combined should it fulfil more than one of the abovementioned objectives (except a secondary well barrier can never be a primary well barrier for the same reservoir).

A secondary well barrier for one reservoir formation may act as a primary well barrier for a shallower formation, if this well barrier is designed to meet the requirements of both formations.

9.3.2 Positioning of well barriers

Well barriers should be installed as close to the potential source of inflow as possible, covering all possible leak paths.

The primary and secondary well barriers shall be positioned at a depth where the estimated formation fracture pressure at the base of the plug is in excess of the potential internal pressure.

The final position of the well barrier/WBEs shall be verified.

9.3.3 Materials

The materials used in well barriers for plugging of wells shall withstand the load/ environmental conditions it may be exposed to for the time the well will be abandoned. Tests should be performed to document long term integrity of plugging materials used.

9.3.4 Leak testing and verification

When inflow testing or leak testing from above to verify the integrity of a well barrier is not possible, or when this may not give conclusive results, other means of ensuring proper installation of a well barrier shall be used. Verification through assessment of job planning and actual job performance parameters are options available.

Inflow tests shall be documented.

9.3.5 Sidetracking

The original wellbore shall be permanently abandoned prior to a side-track/ slot recovery.

9.3.6 Suspension

Suspension of operations requires the same number of well barriers as other abandonment activities. However, the need for WBE testing, and verification, can be compensated by monitoring of its performance, such as fluid level/ pressure development above well barriers. Well fluids (see Table 1) may in such cases be qualified as a WBE.

9.3.7 Temporary abandonment

It shall be possible to re-enter temporarily abandoned wells in a safe manner.

Integrity of materials used for temporary abandonment should be ensured for the planned abandonment period times two. Hence, a mechanical well barrier may be acceptable for temporary abandonment, subject to type, planned abandonment period and subsurface environment.

Degradation of casing body should be considered for longer temporary abandonment scenarios.

Temporarily abandoned subsea wellheads and templates shall be protected from external loads in areas with fishing activities, or other seabed activities etc. Hence for deep water wells, temporary seabed protection can be omitted if there is confirmation of no such activities in the area and at the depth of the abandoned seabed installations.

The pressure in tubing and annulus above the reservoir well barrier ("A" annulus) shall be monitored if a subsea completed well is planned abandoned for more than one year. An acceptable alternative if monitoring is not practicable may be to install a deep set well barrier plug.

For surface completed wells, it should be possible to monitor the pressure in the "A" annulus and in the last tubular that was installed (production tubing, casing).

9.3.8 Permanent abandonment

9.3.8.1 General

Permanently plugged wells shall be abandoned with an eternal perspective, i.e. for the purpose of evaluating the effect on the well barriers installed after any foreseeable chemical and geological process has taken place.

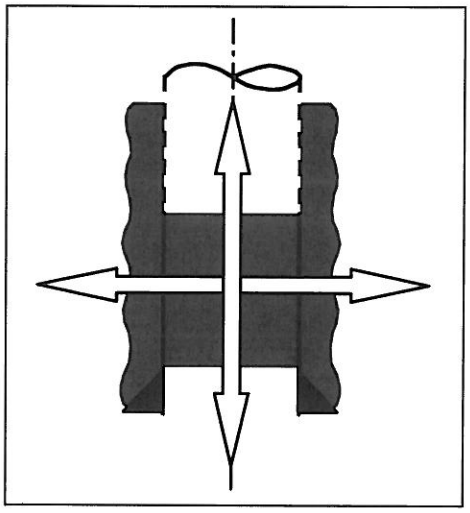
There shall be at least one well barrier between surface and a potential source of inflow, unless it is a reservoir (contains hydrocarbons and/ or has a flow potential) where two well barriers are required.

When plugging a reservoir, due attention to the possibilities to access this section of the well (in case of collapse, etc) and successfully install a specific WBE should be paid.

The last open hole section of a wellbore shall not be abandoned permanently without installing a permanent well barrier, regardless of pressure or flow potential. The complete borehole shall be isolated.

9.3.8.2 Permanent well barriers

Permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally (see illustration). Hence, a WBE set inside a casing, as part of a permanent well barrier, shall be located in a depth interval where there is a WBE with verified quality in all annuli.



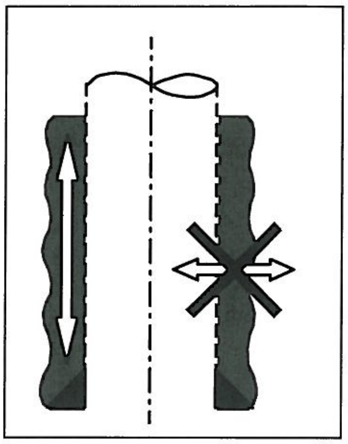
A permanent well barrier should have the following properties:

a) Impermeable
b) Long term integrity.
c) Non shrinking.
d) Ductile – (non brittle) – able to withstand mechanical loads/ impact.
e) Resistance to different chemicals/ substances (H_2S, CO_2 and hydrocarbons).
f) Wetting, to ensure bonding to steel.

Steel tubular is not an acceptable permanent WBE unless it is supported by cement, or a plugging material with similar functional properties as listed above, (inside and outside).

Elastomer seals used as sealing components in WBEs are not acceptable for permanent well barriers.

The presence and pressure integrity of casing cement shall be verified to assess the along hole pressure integrity of this WBE. The cement in annulus will not qualify as a WBE across the well (see illustration).



Open hole cement plugs can be used as a well barrier between reservoirs. It should, as far as practicably possible, also be used as a primary well barrier, see Table 24.

Cement in the liner lap, which has not been leak tested from above (before a possible liner top packer has been set) shall not be regarded a permanent WBE.

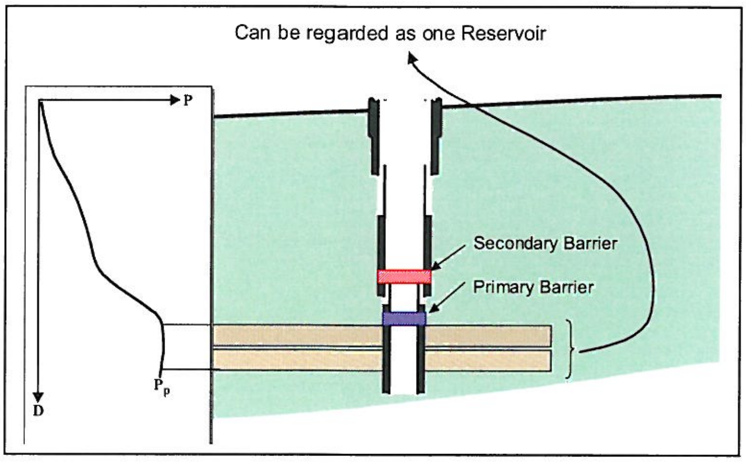
Removal of downhole equipment is not required as long as the integrity of the well barriers is achieved.

Control cables and lines shall be removed from areas where permanent well barriers are installed, since they may create vertical leak paths through the well barrier.

When well completion tubulars are left in hole and permanent plugs are installed through and around the tubular, reliable methods and procedures to install and verify position of the plug inside the tubular and in the tubular annulus shall be established.

9.3.8.3 Special requirements

Multiple reservoir zones/ perforations located within the same pressure regime, isolated with a well barrier in between, can be regarded as one reservoir for which a primary and secondary well barrier shall be installed (see illustration).



9.4 Well barrier elements acceptance criteria

9.4.1 General

Subclause 9.8 lists the WBEs that constitute the primary and secondary barriers for situations that are illustrated.

9.4.2 Additional well barrier elements (WBEs) acceptance criteria

The following table describes features, requirements and guidelines which are additional to what is described in Clause 15.

No.	Element name	Additional features, requirements and guidelines
Table 2	Casing	Accepted as permanent WBE if cement is present inside and outside.
Table 22	Casing cement	Accepted as a permanent WBE together with casing and cement inside the casing. Should alternative materials be used for the same function a separate WBEAC shall be developed.
Table 24	Cement plug	Cased hole cement plugs used in permanent abandonment shall be set in areas with verified cement in casing annulus. Should alternative materials be used for the same function a separate WBEAC shall be developed. A cement plug installed using a pressure tested mechanical plug as a foundation should be verified by documenting the strength development using a sample slurry subjected to an ultrasonic compressive strength analysis or one that have been tested under representative temperature and/or pressure.

No.	Element name	Additional features, requirements and guidelines
Table 25	Completion string	Accepted as permanent WBE if cement is present inside and outside the tubing.
Table 43	Liner top packer	Not accepted as a permanent WBE.

9.4.3 Common well barrier elements (WBEs)

A risk analysis shall be performed and risk reducing measures applied to reduce the risk as low as reasonable practicable, see 4.2.3.3.

The following table describes risk reducing measures that can be applied when a WBE is an element in the primary and secondary well barrier:

No	Element name	Failure scenario	Probability reducing measures	Consequence reducing measures
Table 2	Casing	Leak through casing and into annulus, with possibility of fracturing formation below previous casing shoe.	None	Cement in the annulus with verified TOC above the section that is common.

9.5 Well control action procedures and drills

9.5.1 Well control action procedures

The following table describes incident scenarios for which well control action procedures should be available (if applicable) to deal with the incidents should they occur. This list is not comprehensive and additional scenarios may be applied based on the actual planned activity, see 4.2.7.

Item	Description	Comments
1.	Cutting of casing.	Trapped gas pressure in casing annulus.
2.	(SSW) Pulling casing hanger seal assembly.	Trapped gas pressure in casing annulus.
3.	Re-entry of suspended or temporary abandoned wells.	Account for trapped pressure under plugs due to possible failure of suspension plugs.

9.5.2 Well control action drills

The following well control action drills should be performed:

Item	Description	Comments
1.	Pressure build-up, or lost circulation in connection with a cutting casing operation.	To verify crew response in applying correct well control practices.
2.	Loss of well barrier whilst performing inflow test.	

9.6 Suspension, plugging and abandonment design

9.6.1 Design basis, premises and assumptions

Depths and size of permeable formations with a flow potential in any wellbore shall be known.

All elements of the well barrier shall withstand the pressure differential across the well barrier at time of installation and as long as the well barrier will be in use, see 9.3.3.

The following information should be gathered as a basis of the well barrier design and abandonment programme:

a) Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
c) Logs, data and information from primary cementing operations in the well.
d) Estimated formation fracture gradient.
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, or similar issues.

The design of abandonment well barriers consisting of cement should account for uncertainties relating to

- downhole placement techniques,
- minimum volumes required to mix a homogenous slurry,
- surface volume control,
- pump efficiency/ -parameters,
- contamination of fluids,
- shrinkage of cement.

9.6.2 Load cases

Functional and environmental loads shall be combined in the most unfavourable way.

For permanently abandoned wells, the specific gravity of well fluid accounted for in the design shall maximum be equal to a seawater gradient.

The following load cases should be applied for the abandonment design:

Item	Description	Comments
1.	Minimum depth of primary and secondary well barriers for each reservoir/potential source of inflow, taking the worst anticipated reservoir pressure for the abandonment period into account.	Not shallower than formation strength at these depths. Reservoir pressure may for permanent abandonment revert to initial/virgin level.
2.	Leak testing of casing plugs.	Criteria as given in Table 24.
3.	Burst limitations on casing string at the depths where abandonment plugs are installed.	Cannot set plug higher than what the burst rating allows (less wear factors).
4.	Collapse loads from seabed subsidence or reservoir compaction.	The effects of seabed subsidence above or in connection with the reservoir shall be included.

9.6.3 Minimum design factors

The design factors shall be as described in 5.6.4 and 7.6.4.

9.7 Other topics

9.7.1 Risks

Risk shall be assessed relating to time effects on well barriers such as long term development of reservoir pressure, possible deterioration of materials used, sagging of weight materials in well fluids, etc.

HSE risks related to removal and handling of possible scale in production tubing shall be considered in connection with plugging of development wells.

HSE risk relating to cutting of tubular goods, detecting and releasing of trapped pressure and recovery of materials with unknown status shall be assessed.

9.7.2 Removing equipment above seabed

Use of explosives to cut casing is acceptable only if measures are implemented (directed/ shaped charges and upward protection) which reduces the risk to surrounding environment to the same level as other means of cutting casing.

For permanent abandonment wells, the wellhead and the following casings shall be removed such that no parts of the well ever will protrude the seabed.

Required cutting depth below seabed should be considered in each case, and be based on prevailing local conditions such as soil, sea bed scouring, sea current erosion, etc.. The cutting depth should be 5 m below seabed.

No other obstructions related to the drilling and well activities shall be left behind on the sea floor.