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Abstract

There will be a wave of wells needing to be abandoned in the North Sea over the next decades. The abandonment operation is known as Plug and Abandonment, or just P&A. As P&A has no value creation, it is very important that these operations are conducted as effective as possible. Currently, operations are mainly completed using conventional methods, and for P&A to be economically sustainable in the future there is a great need for new technology and methods. In addition, regulators can play a part in achieving more effective operations by tailoring requirements and guidelines. In Norway, P&A operations are still based on a standard released in 2004, meaning that there is a potential for improvements.

In this thesis the standard that governs P&A operations in Norway was analysed and compared with the guidelines used on UK sector to find ways of improving NORSOK D-010. UK sector has more experience with regards to P&A, and use a guideline published in 2012. This ended in several proposed changes in NORSOK D-010, but also suggestions for additional guidelines for the NCS.

To show how alternative technology and methods can be used to improve P&A operations several solutions were presented, including all phases of well abandonment, both for platform and subsea wells. In addition rigs and vessels used in P&A were described, as one of the most important future goals is performing operations rigless. For platform P&A the goal is performing offline operations, meaning eliminating the use of the derrick. For subsea abandonment there exist a great potential in moving operations away from the traditionally used semi-submersibles, and to smaller and significantly cheaper light well intervention vessels (LWIs). Technology and vessels use were later combined in several example cases to give an overview over how operations can improve. In the future operators must be willing to utilize alternative technology in the field, and continue to push for research and development on newer technology to solve the many challenges in P&A operations.

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List of Abbreviations

AFE	Authorization For Expenditure
BOP	Blowout Preventer
CBL	Casing Bond Logging
COP	Cessation Of Production
CT	Coiled Tubing
ECD	Equivalent Circulation Density
GoM	Gulf of Mexico
KPI	Key Performance Indicator
LWIs	Light Well Intervention vessels
MO(D)U	Mobile Offshore Drilling Unit
NCS	Norwegian Continental Shelf
NORSOK	Norsk Sokkel Standard
NPT	Non Productive Time
OH	Open Hole
PP&A	Permanent Plug and Abandonment
PSA	Petroleum Safety Authority Norway
PWC	Perforate, Wash and Cement
R&D	Research and Development
RLWIs	Riserless Light Well Intervention vessels
SCP	Sustained Casing Pressure
TCP	Tubing Conveyed Perforating
TOC	Top Of Cement
TOGI	Troll Oseberg Gas Injection
UKCS	UK Continental Shelf
UKG	Guidelines for the suspension and abandonment of wells
USIT	Ultra Sonic Imaging Tool
WBE	Well Barrier Element
WBS	Well Barrier Schematics
WBEAC	Well Barrier Element Acceptance Criteria
WL	Wireline
WOW	Wait on Weather
X-mas	Christmas three

1. Introduction

Every well drilled offshore, no matter if it is an exploration, development, subsea or platform well, has to be permanently plugged and abandonment at some time. This is known as PP&A, or just P&A. In an industry solely based on maximizing profit and minimizing cost, P&A is becoming an increasing challenge. Not only is it costly and time consuming, but well abandonment is often completed using rigs that should be used for drilling new wells to generate value. For the NCS, there has been little emphasis on P&A. This is due to the fact that the first wells did not start producing until the 1970´s, with the large discoveries found in the following decades still producing. Now the problem is very present, and a wave of wells needing to be permanently abandoned will increase rapidly for the next 20-30 years.

According to an internal presentation in Statoil [1], the company has planned to permanently abandon approximately 1200 wells in the next 40 years, with figure 1 and 2 [1] illustrating how this number rapidly increase towards year 2030. Another study presented by the Petroleum Safety Authority Norway at Stavanger SPE meeting October 2012 [2], states that on UK sector a total of 4600 wells are to be PP&A over the next 15 years, including approx. 3700 platform well and 900 subsea wells. The abandonment of these wells would equal to 97 rig years for the platform wells, and 26 years for the subsea wells [2]. These are extreme numbers, and will be very costly and time consuming for operators. The need for new technology is obvious, and in a conservative industry like the petroleum industry, the operators need to push for and be willing to try out alternative methods. This is especially important on the NCS, which historically does not have great experience with P&A compared to the UKCS and GoM.

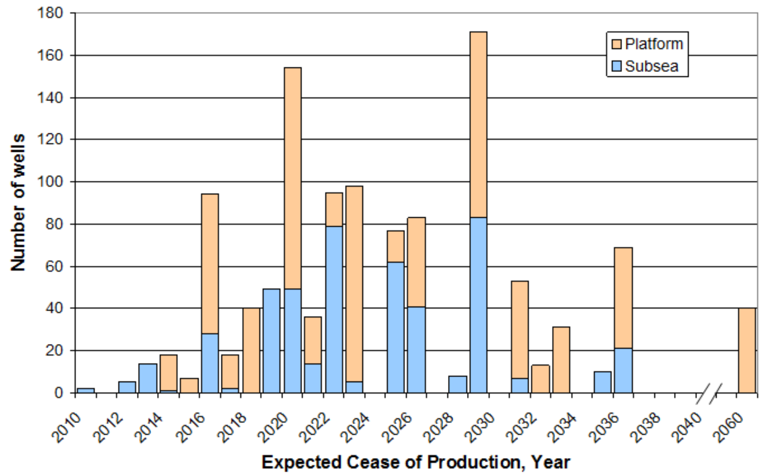


Figure 1: Number of planned wells Statoil is to PP&A [1]

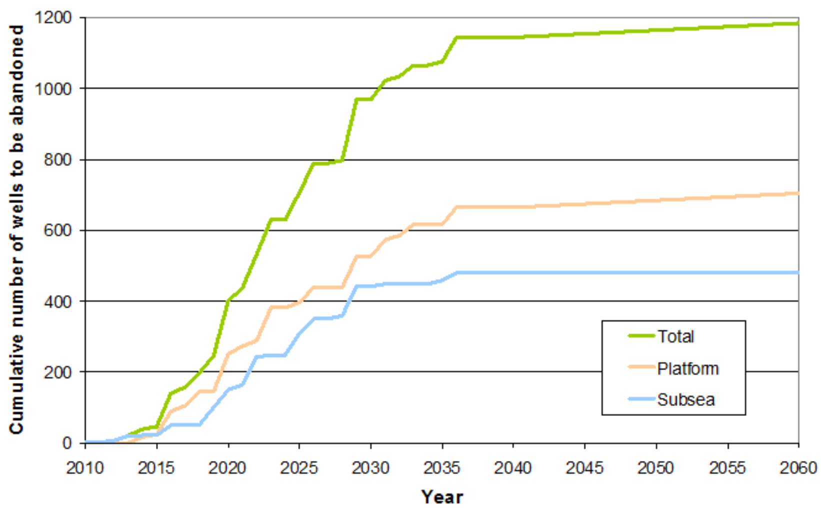


Figure 2: Cumulative number of wells Statoil is to PP&A [1]

Although technology is probably the most important area when it comes to solving P&A challenges, it is also important to look elsewhere. According to Statoil, an average P&A operation on the NCS took 16 days in the period 2000-2004. This number suddenly increased to 35 days in the period 2004-2010, as shown in figure 3 [1]. There can be several reasons for this happening, but one very interesting fact is that NORSOK D-010 rev. 3, being the guidelines that govern all drilling and well operations on the NCS, was published in August 2004. This means that regulations and guidelines can have a big impact on P&A operations, and should be studied to find improvements that can make operations more efficient.

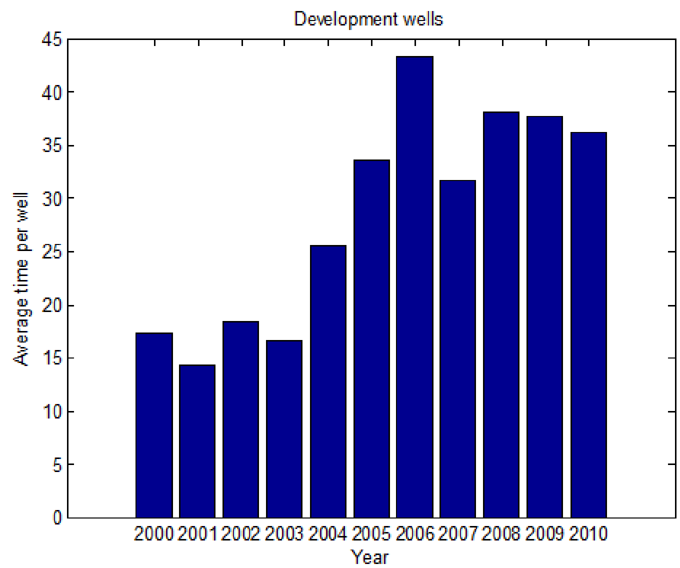


Figure 3: Average operational time for P&A of wells [1]

This thesis will look into new and alternative technologies to permanently abandon wells. It will cover all phases of a P&A operation, from pulling completion to removing the wellhead. Another goal of the thesis is looking into possible improvements of NORSOK D-010. This will mainly be done by comparing this to the *Guidelines for the suspending and abandonment of wells, issue 4* [2012] which is the guideline used for P&A on the UKCS, to see if there is anything that can be learned to improve NORSOK D-010.

2. What is P&A?

A P&A operation is not straightforward. It is a complex operation that need detailed planning, thorough cost and risk estimation, and with large emphasis on safety. It consists of several phases, starting with plugging the reservoir, and ending with wellhead removal. In this chapter the P&A operation will be explained in a simple way, with more detailed descriptions in chapter 3 where the guidelines that govern P&A operations both in Norway and UK will be analysed. But it is impossible to describe a P&A operation without touching into these, so in the following the standard used on the NCS, NORSOK D-010, will be used to some degree. Abandonment of wells also presents several challenges, and the most important ones will be described in this chapter.

2.1 P&A definition

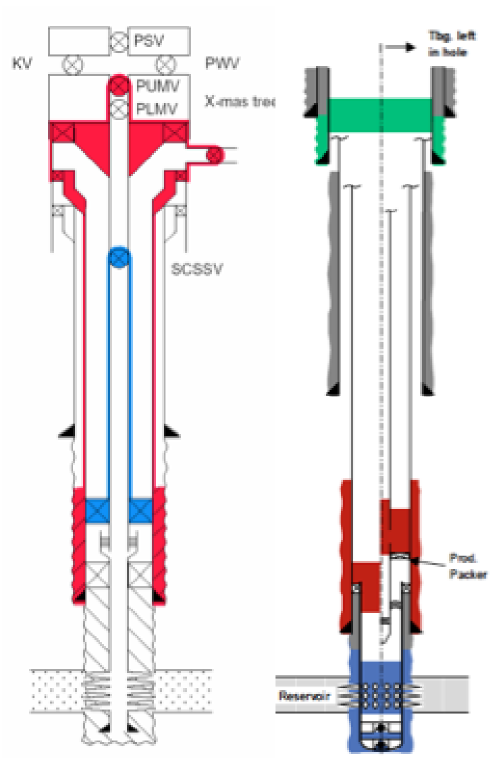
After a well has served its purpose, either as an exploration well, production well or injection well, it has to be plugged and abandonment. The whole point of well abandonment is that the environment never will be exposed in a negative way as a result of the well being left behind, especially with regards to hydrocarbons. But not only that, the area of interest shall be left behind with none "visible" traces or obstructions relating to drilling and well activities. Saying this in a simple way, the area should be left behind as if no activity had ever been conducted.

According to NORSOK D-010, a well can be abandoned in two different ways; temporary or permanently. Temporary P&A is often done when a well is to be re-entered or permanently abandoned in the future. The focus of this thesis is permanent P&A, so unless stated temporary P&A, the term P&A refers to permanent plug and abandonment.

A well is plugged mainly because of two reasons. One is that the reservoir section is deemed no longer economical or has fulfilled its purpose, but the well is to be reused. This is done by first permanently abandoning the original wellbore, typically by setting required barriers against the reservoir, and then drilling a side-track; a process called slot recovery. The other reason is when the whole well, including all side-tracks/laterals, has fulfilled its purpose and is to be permanent plugged and abandoned. This is a more severe operation as the well is to be left behind for eternity [3]. Slot recovery is not an important part of this thesis.

2.2 General operational procedure

(1) and (2) in figure 4 are taken from NORSOK D-010 and shows a typical well configuration prior to and after a P&A operation. (2) shows both the configuration for tubing left in hole, and with tubing pulled. Also in the picture, the well barrier elements (explained in chapter 3) and their corresponding explanation are included. In this section, the general operational procedure for P&A will be covered, and will typically show how to go from (1) to (2).



(1) (2)

Well barrier elements	See Table	Comments
Primary well barrier		
1. Liner cement	22	
2. Cement plug	24	Across and above perforations.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
or, for tubing left in hole case:		
1. Casing cement	22	
2. Cement plug	24	Inside and outside of tubing.
Open holes to surface well barrier		
1. Cement plug	24	
2. Casing cement	22	Surface casing.

Notes
1. Cement plugs inside casing shall be set in areas with verified cement in casing annulus.
2. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Figure 4: Typical well schematic prior and after completed P&A operation, including explanation for (2) [3]

2.2.1 The well prior to P&A operation

When the well is to be abandoned, the well is first killed. This is accomplished by pumping a heavy fluid to make the well overbalanced. After this, the normal procedure is to run a

USIT/CBL log. This is a logging run done to verify the quality of the cement on the outside of the lower completion (if cemented casing/liner is used). In (2) from figure 4 the lower completion is a perforated liner that has been cemented up to the liner hanger. The logs must verify the quality of cement on the outside of the area where the cement plug will be set, as the plug has to extend across the full cross section of the well, including all annuli, and seal both in horizontal and vertical direction [3].

2.2.2 Pulling the tubing

As shown in figure 4, the production tubing/upper completion can be either pulled or left in hole. But in most cases the tubing needs to be pulled for various reasons (e.g. removal of control lines, see section 2.3.10). This is a heavy operation that needs machinery that can handle high loads. For platform wells the drilling facilities are in most cases used, but there is alternative equipment that can be used as well. For subsea wells, semi-submersibles or jack-up rigs are in most cases used. The normal procedure is to cut the tubing above the production packer (if not retrievable), remove the X-mas tree, install the BOP and then pull the tubing.

2.2.3 Establishing barriers

Before installing the barriers, it is normal to log the previous casing; in figure 4 this is typically a 9 5/8" casing. This is done to check the quality of casing cement in this interval.

According to NORSOK D-010, there has to be at least one permanent well barrier between the surface and a potential source of inflow, but when it comes to a source containing hydrocarbons, there has to be two. Independent of the configuration of the well, all barriers have to be above this source of inflow. Meaning that if a well has a completion solution with perforations through the reservoir, cement across this section will not count as a part of the permanent barriers since they have to be installed above the reservoir. But it is normal procedure to cement across the perforations in addition to the barriers.

A permanent well barrier must extend across the full cross section of a well, including all annuli and seal both vertically and horizontally, see figure 10 [3]. Because of this, a plug has to be set at a depth interval where the logs have verified good cement on the outside of the casing, as the casing alone is not an acceptable permanent well barrier element (WBE). NORSOK D-010 also states that the well barriers shall be positioned as close as possible to the source of inflow, and at a depth where the estimated formation fracture pressure at the base of the plug can withstand the potential internal pressure [3]. If good cement is not verified on the outside of the casing, the P&A operation becomes much more complex. The traditional way to cope with this is called section milling, a process described in section 2.3.4.

After permanent well barriers are set against relevant formation(s), they have to be inflow tested or leak tested from above to verify their integrity.

This was a very simplified example of establishing barriers. There are many different scenarios that require different solutions, and the WBEs have several different requirements. This will be covered in chapter 3.

2.2.4 Surface plug and wellhead removal

NORSOK D-010 states that the last open hole section of a wellbore shall not be abandoned without installing a permanent well barrier, regardless of pressure and flow potential. As with the primary and secondary barriers, this open hole to surface barrier has to plug the whole cross section of the well [3]. Figure 4 shows typically where the surface plug is set (green). The two first set casings, typically the 30” conductor and 20” surface casing, are cemented all the way up to the wellhead, while the following casings (here 9 5/8” and 13 3/8”) are in most cases not cemented all the way. This means that the 9 5/8” and 13 3/8” casings often needs to be cut and pulled in the interval where the surface barrier is to be installed. After the relevant casings are pulled, the surface plug can be set if verified good cement on the outside of the 20” casing. There are no requirements for setting depth of the surface barrier, just that the complete borehole shall be isolated.

After the surface plug is installed, NORSOK D-010 states that the wellhead and the following casings must be removed as no parts of the well can ever protrude the seabed. The cutting depth should be considered in each case, and be based on prevailing local conditions like soil, sea bed scouring, current erosion, etc. But NORSOK D-010 states that the cutting depth *should* be 5 m below seabed, and this depth is used as the reference on the NCS [3]. The conventional way of cutting the wellhead and the following casings is either using cutting knives, or the use of explosives.

After all “obstructions” relating to drilling and well activities like the wellhead, different downhole equipment, templates, etc. has been removed, the rig itself needs to be removed. For subsea wells, this is often an easier operation if production boats or semi-submersibles have been used. But for platforms wells, the platform itself needs to be removed, and this is called decommissioning. This is an extremely challenging operation, where tens of thousand tonnes of steel need to be removed. One example of the decommissioning process is the cessation of the Frigg field. This took 10 years, and resulted in nearly 90,000 tonnes of steel brought to land for scrapping. The only structures remaining are the three concrete gravity based structures [4]. Decommissioning is not a part of this thesis.

2.3 P&A challenges

Permanent well abandonment introduces several challenges. Each well is unique, and the operations can be quite complex. In the North Sea, a wave of wells is to be permanently plugged and abandoned in the following decades, known in the industry as the “plug wave”. For this to be economically sustainable for operators, several challenges need to be faced and solved in the near future.

2.3.1 The current situation

Earlier, P&A has not had a lot of attention on the NCS. The first fields started producing in the 70s, and most of the biggest fields are still producing. But for the next 30-50 years, this will change, and change dramatically. As mentioned in the introduction, Statoil alone plan to plug and abandon about 1200 wells; with a rapid increase towards year 2030 (figure 2). With the high number of wells needing to be abandoned, P&A will be very expensive and time consuming for Statoil and other operators on the NCS.

2.3.2 Rig capacity

This is a problem directly linked to the enormous quantity of wells needing to be permanently abandoned in the future. An internal report in Statoil was made in 2011 to estimate time and cost relating to permanent P&A of development wells operated by the company [8]. It showed that in the period 2012-2020, an average of 1 rig/year will be occupied with P&A operations, while for the period 2020-2025 where an explosive increase in P&A operations will occur, an average of 2 MOU and 3-4 fixed units will be occupied with P&A operations each year. The total estimated cost was 38 BNOK for the platform wells, and 60 BNOK for subsea wells, which gives a total of 98 BNOK. Both the rig years and cost are illustrated in figure 5 [8], and this shows the enormous expense P&A will be for Statoil. And as P&A is an operation with no value potential, using rigs for P&A operations not only lead to high cost, but also lost potential revenue since the rigs are not used for drilling new wells. It is important to stress that these figures are based on current technology, the use of rigs (not LWIs), expectations to rig marked, current rules and regulations and other uncertain variables that can change in the foreseeable future.

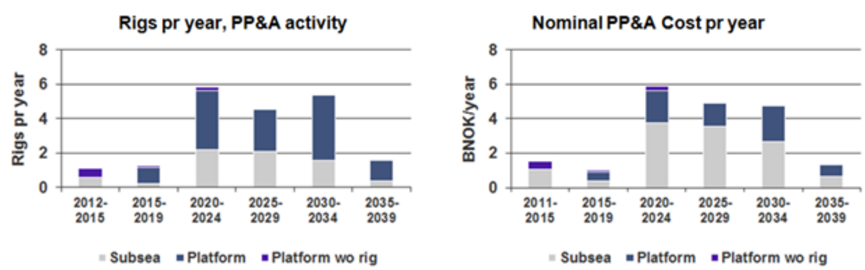


Figure 5: Time and cost estimation for P&A of Statoil wells [8]

For fixed platform wells, the challenge is how to find solutions to perform *offline* P&A operations, meaning how to eliminate the use of drilling rigs. For subsea wells, the goal is how to minimize or eliminate the use of semi-submersibles. The use of Light Well Intervention vessels (LWIs) for P&A operations has been more used in recent time, especially on the UKCS. The goal for the future should be to go from partial P&A of subsea wells, to full P&A using LWIs. To put this in numbers, according to a presentation by Subsea P&A AS at P&A seminar June 2011 [5], moving the P&A operation of approximately 1000 North Sea subsea wells from rigs to

LWIs will result in a saving potential of 150billion NOK. But for this to be possible, there are technology gaps that need to be filled in order for LWIs to perform full P&A operations, mainly being;

- Pulling tubing/casing (without riser)
- Displacing cement from LWIs (without riser)
- General P&A challenges

2.3.3 Present well status

Many of the wells that need to be permanently abandoned are old, and the data available from these wells can be quite inadequate. Especially lacking information regarding cement quality behind casing strings can be a big problem.

It is also important to have information about any pressure build up in the annulus of wells. In subsea wells, this is a challenge as most annuli cannot be monitored (A-annulus can be monitored). If there is trapped gas in annulus when cutting casing for removal of the wellhead, a serious well control incident can rapidly occur as the BOP is a short distance away from the source of inflow (the cut casing), meaning that there is very little time to react before the gas reaches the BOP. Because of this, Statoil has a requirement that the casings shall be cut/perforated with pressure control equipment (annular preventer) activated to relieve any pressure in annuli between casings before pulling the casing/wellhead. For deeper cut/perforations it can be sufficient to be aware if needing to activate well control equipment.

The lack of information on the well's status makes it necessary for thorough preparation work before starting the P&A operation. It can also force the use of rigs with conventional BOP and riser to be able to do the job with best possible pressure control readings.

2.3.4 Re-establishing barrier elements

As explained in section 2.2.3, a permanent well barrier is required to extend across the full cross sectional area of the well. If a well barrier is set inside casing, there has to be verified good cement on the outside of the casing, since the casing alone is not accepted as a WBE [3]. A Statoil R&D study on P&A identified 2 major time-consuming operations, where one was re-establishing barrier elements behind casing [1]. This is often a result of poor cement jobs from when the well was drilled, with cement behind casing being of low quality or in some cases totally absent. The traditional way of dealing with poor cement jobs behind casing, is section milling. This is a process where the casing is milled away to achieve access to the annulus, with all the metal debris (swarf) returned to surface. Section milling has several negative impacts:

- Time consuming
- Swarf handling
- Section milling cause high ECD- which can lead to formation fracturing

Handling the swarf is the biggest challenge. Figure 6 [1] shows how the swarf typically look like, and it is obvious that this chunk of steel can cause serious problems downhole. Swarf cause higher ECD, it can make bird nests that cause stuck pipe, it can harm critical equipment like the BOP when circulated out, and needs to be handled when coming out of the well. The only way to truly eliminate the swarf problem is to avoid milling operations all together. There has been technology advances in this area, and these will be presented in a later chapter. Other technology development plans identified for this include [1]:

- Elimination of swarf return during milling operations (e.g. by leaving it behind in hole, R&D study in Statoil on-going)
- Avoid exposing critical equipment like the BOP to swarf

Figure 6: Typical example of swarf [1]

The need to re-establish barrier elements is often a result of well designs not having P&A in mind when planned. Many of the wells were constructed decades ago, and a typical human bias is to have little care for issues that will occur in many years, with future generations left to deal with it. This means that wells can have been constructed with poor cement jobs being accepted without any thought for well abandonment. In addition the technology advances and experiences were not as high as now. This show how important it is to simplify future P&A of new wells by improved design and/or adding special equipment to eliminate the need for operations like section milling. This can save a great amount of time and money for operators in the future.

2.3.5 Sufficient formation strength to withstand future reservoir pressure

The formation strength at the base of the well barriers has to withstand pressures from below formations (see section 3.2.1.2). In old wells, knowledge about formation strength can be missing and obtaining this information then becomes a part of the P&A operation. This then requires conducting physical tests on the formation in the area where the barriers are to be established, with it adding an operation that should have been unnecessary.

2.3.6 Casing/tubing collapse

If wells are located in fields where formation or seabed has been subject to subsidence due to depletion, this may lead to shear stresses that can cause tubing/casing to collapse or shear, making it nearly impossible to enter the well below the depth the damage have occurred. The problem with regards to P&A occurs when the permanent well barriers have to be set at a depth below this area to achieve sufficient formation strength (see 3.2.1.2).

2.3.7 Removal of casing strings

The other major time-consuming factor identified by the Statoil R&D study was removal of casing strings [1]. The need to remove casing can be for different reasons. One is re-establishing barriers as mentioned in 2.3.4. Before section milling becomes an alternative, casing is first cut and tried pulled if deemed possible. This often becomes difficult because of factors like collapsed formation, settled mud particles, or traces of cement as a result of poor cement jobs.

Sometimes there is a need to pull casing just to get access for logging. For now, logs cannot log satisfactory through multiple casing strings, so the only way to achieve this is to pull casing to gain access to the area of interest. Being able to log through multiple casing strings in the future would greatly improve planning of P&A operations, and save a lot of time.

Another reason for having to pull casing is when installing barriers against other formations than the main reservoir, often found higher up in the subsurface. An example of this is found on Statfjord A, illustrated in figure 7 [6]. As previously mentioned, NORSOK D-010 requires 2 barriers against all hydrocarbon bearing formations. In figure 7, we have the normal procedure with 2 barriers installed against the main reservoir (Brent and Statfjord formations). But the shallower Rogaland group also contains traces of hydrocarbons, meaning it needs to be treated as a reservoir. As figure 7 shows, there is a need to cut and pull the 9 5/8" casing to gain access to the annulus before setting the barriers. This is at a depth of almost 2000m MD, meaning that almost 2000m of casing needs to be removed. This will obviously take time, especially when casings often needs to be cut at several intervals, and pulled piece by piece as pulling a long interval of casing in one cut is very difficult. As for re-establishing the barriers, the main goal should be finding methods that eliminate the need to pull casing to gain access to areas where barriers are to be installed.

The last reason that may require removal of casing is when installing the surface barrier, seen as the shallowest plug in figure 7, since the last open hole section of a well needs one permanent barrier installed (see section 3.2.1.1). As we see from the figure, this requires that two casing intervals are removed.

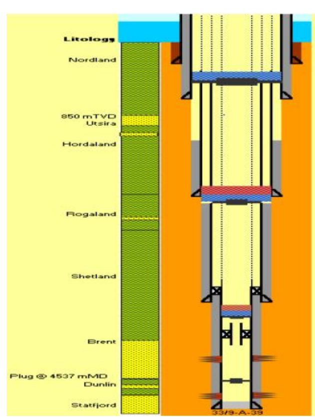


Figure 7: Typical P&A situation from Statfjord A well [6]

2.3.8 Cement logging

The most common method to verify the quality of casing cement is logging. The data retrieved from the logs need to be reliable, since the cement will be a part of a permanent barrier that will stay downhole for eternity. According to a presentation by Tore Weltzin at P&A seminar June 2012 [6], which takes on the P&A challenges experienced on Statfjord A, there are several challenges relating to logging. Some of these are;

- Lack of log data from older wells
- Logs show bad cement quality even when the jobs are known to be successful
- Different results for same job when log is repeated
- Have to pull casing to get access to logging (as mentioned in 2.3.7)

Furthermore, the interpretation of data collected from logs is often linked to personal opinions, as the expertise to really understand the logs are limited and often with the suppliers. Having data that is not trusted from logs, increase the risk of cement remedial jobs in many wells (section 2.3.4).

2.3.9 Using formation as barriers

A newer topic relating to P&A is using formation as a part of barriers. During logging operations in casing above the predicted top of cement, it can be observed intervals that show log responses similar to good cement bonding. This type of response is most likely a result of solid materials that are hard packed onto the outside casing surface. In most cases there is good correlation between shale/clay zones and zones showing good cement bonding [7]. If there is sufficient amount of formation packed onto the outside of the casing, it can be used as a part of well barriers as a substitute for cement. According to a presentation by Truls Carlsen (Statoil) at P&A seminar June 2012 [7], this approach has been used to solve barrier issues on more than 100 wells in Statoil, with an average cost reduction per well estimated to 15 MNOK. For the field abandonment of Statfjord A, using formation as WBEs is relevant for several wells, and can save up to 210 days [6]. The gains are clear as this can replace critical operations like section milling and casing pulling. The challenge is to find logs that accurately can determine the formation as a barrier, and making it an integrated part of the regulations like in the UK guidelines (will be described more in chapter 3).

2.3.10 Removal of control cables and lines

Intelligent well completions were introduced to remotely monitor and control wells. This has revolutionized the ability to control downhole conditions; with the downhole equipment controlled by different set of control cables and lines. But for P&A operations this is an issue, as NORSOK D-010 requires control cables and lines removed if they are positioned in areas where the barriers are to be set, since they create vertical leak paths [3]. The only way to surely remove the cables currently is to remove the entire tubing they are attached too. As previously mentioned, removing tubing needs equipment that can handle the heavy loads and is often time consuming, thus making it an expensive part of a P&A operation. The challenge is finding technology able to cut the lines/cables and verifying this is done, and thereby eliminating the need to pull tubing just to get the lines/cables removed.

2.3.11 Services involved in P&A operations

For Statoil the services involved in P&A operations are mainly a result of frame agreements. For other operations like top side drilling, logging, drilling fluids, wireline, cementing and tubing handling, a service company and drilling contractor are rewarded contracts to specific fields and platforms for a longer duration. For P&A operations in Statoil, contracts are often given on a well to well basis. The result can be less time on project planning for the service companies, and also less development of P&A operations for both the service companies and operators at a given field. Figure 8 [9] illustrates a typical example of a possible way to handle this issue. The P&A of a specific field is done in cooperation between Statoil, P&A service providers and the drilling rig contractor. Different important aspects can be [9]:

- KPI based agreements
- KPI to be adjusted as work progress
- Payment based on KPI achievement
- Establishing a win-win situation between Statoil and service companies

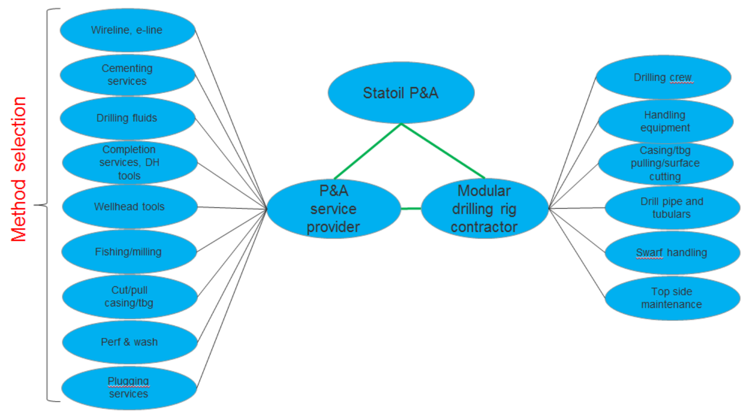


Figure 8: Example of a possible P&A model [9]

Using the model in figure 8 can make P&A operations more efficient. With KPI based agreements, the service providers and rig contractor will be constantly monitored and rated against a pre-agreed number. In addition, having a specific field to work towards the KPIs can be adjusted as operations develop and service providers get more familiar with a field. Payment can be based on KPI achievement, as well as being a very important factor for future contracts. This can help establish a win-win situation for all parties, where service providers get more income as P&A operations become more efficient, and where Statoil saves a great amount of time. It has to be said that this is just an example of a possible model, the challenge is to find how we can make P&A operations more efficient, meaning that all areas has to be evaluated and reconsidered.

2.3.12 Temporary abandoned wells

As for now, there are no requirements on how long wells can be temporary abandoned on the NCS. There is an industry consensus that this should not be for more than 3 years, but in most cases this is not followed. As there is no value creation with P&A and no requirements on duration of temporary abandonment, it is easy to postpone permanent P&A operations and focus more on value creating areas like drilling. This leads to a great number of wells being temporary abandoned, which increase the number of wells needing to be permanently abandoned in the future. One example on what this can lead to is from the GoM. A study performed in 2011 [2] concluded that approximately 3600 wells are temporary abandoned, with the oldest done in the fifties. Out of these, only 38% of the wells are planned to be reused, meaning that approximately 2200 wells are temporary abandoned with no planned future use.

After the Macondo accident, U.S regulations changed, stating that wells can be suspended/left for 5 years, and then have to be abandoned within 2 years [2]. If this requirement is to be fulfilled in the GoM, operators have an enormous task in hand with all those wells. The PSA has the following recommendation to solve this issue for the NCS; some are [2];

- New wells (exploration wells) not planned to be used in the future should be permanently P&A as soon as finished
- Temporary P&A is meant to be temporary and the industry should focus more on permanent P&A of the existing temporary abandoned wells
- Operators and Licensees should on a regular basis go through each temporary abandoned well and evaluate the well integrity status and plans and need for future use
- Wells should not be temporary P&A for a period longer than 3 years

For the last point, this is a proposed requirement for the new revision of the NORSOK D-010 which is scheduled to be released sometime in 2013.

2.3.13 Regulations and requirements

There should be more emphasis on developing standards and guidelines to help achieve more effective P&A operations. This topic is a very important part of the thesis, and will be discussed in more detail in the following chapter.

3. Regulations and requirements

In the introduction it was mentioned how an average P&A operation in 2004 suddenly increased from 16 days to 35 days in the NCS. This is a severe increase, and cannot just happen overnight. In August 2004, revision 3 of the Norwegian Standard for Well integrity in drilling and well operations, NORSOK D-010, was published. This could be a large contributor for this sudden increase. In this thesis, a comprehensive analysis of the NORSOK D-010 will be conducted, along with the guideline used in UK, *Guidelines for the suspending and abandonment of wells, issue 4* [11]. The UK guidelines were published in 2012, so it is more comprehensive than the P&A section of NORSOK D-010. These will be compared to find possible ways of improving NORSOK D-010, while still ensuring adequate safety, value adding and cost effectiveness for P&A operations.

3.1 Current requirements and guidelines

As this thesis is being written, rev.4 of the NORSOK D-010 is under consideration, and is to be published some time in 2013. The scope of this thesis is current regulations, meaning that rev.3 of NORSOK D-010 is to be analysed.

3.2 NORSOK D-010, rev. 3 (Norwegian Continental Shelf)

"The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities' regulations." [3]. This NORSOK, NORSOK D-010, focus on well integrity in drilling and well operations, and defines minimum requirements and guidelines for well design, planning and execution of well operations in Norway. As NORSOK D-010 includes both requirements and guidelines, it is of great importance to know when to differentiate between them. This is accomplished by the terms *shall* and *should*. *Shall* is the term used to indicate requirements which are to be strictly followed according to the standard and where no deviations are permitted, unless accepted by

all the involved parties. *Should* is a term used to indicate a recommended action among several possibilities, without mentioning or excluding other possibilities [3].

The P&A section of NORSOK D-010 cover three scenarios [3];

- Temporary suspension of well activities and operations
- Temporary or permanent abandonment of wells
- Permanent abandonment of a section of a well to construct a new wellbore with a new target, known as sidetrack/slot recovery

This thesis will mainly look at permanent P&A operations.

3.2.1 Permanent well barriers

3.2.1.1 Permanent P&A

According to NORSOK D-010, a permanent P&A job *shall* be done with an eternal perspective. Further requirements states that there should be at least one permanent well barrier between a potential source of inflow and surface. A potential source of inflow is defined as *formation with permeability, but not necessarily a reservoir* [3]. This requirement does not apply to the case where the formation is a reservoir, with a reservoir defined as a *permeable formation or group of formation zones originally within the same pressure regime, with a flow potential and/or hydrocarbons present or likely present in the future* [3], where the requirement is two permanent well barriers. These requirements can lead to confusion as NORSOK D-010 do not provide any further explanation on the terms “inflow” and “flow potential”. Statoil defines “flow potential” as a formation with permeability and overpressure, meaning that a reservoir can be:

- Formation containing hydrocarbons
- Formation with permeability and overpressure
- Combination of both

Further, NORSOK D-010 requires that the last open hole section of a wellbore shall not be permanent abandoned without installing a permanent well barrier, often known as the surface barrier (open hole to surface barrier). Table 1 [3] show what required function and purpose the different well barriers have.

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.

Table 1: Required well barriers in a permanent P&A operation and their purpose [3]

3.2.1.2 Position of well barriers

According to NORSOK D-010 well barriers should be installed as close as possible to the potential source of inflow. But if the well barriers need to be installed at a shallower depth, the requirement is that the estimated formation fracture pressure at the base of the plugs is higher than the potential internal pressure, both for the primary and secondary plugs [3]. The potential internal pressure is the reservoir pressure minus the reservoir fluid's hydrostatic pressure. The reservoir pressure is not defined specifically in NORSOK D-010, but initial/virgin pressure can be used. The plugs cannot be set shallower than the point where the internal pressure is equal to the formation fracture pressure, illustrated in figure 9. Here the future reservoir pressure is calculated to be 340bar, with the inflow fluid having a gradient equal to 0,27s.g. From the figure one can see that the pressure caused by the reservoir will exceed the formation fracture pressure at approximately 1800m, this then being the shallowest depth a plug can be set.

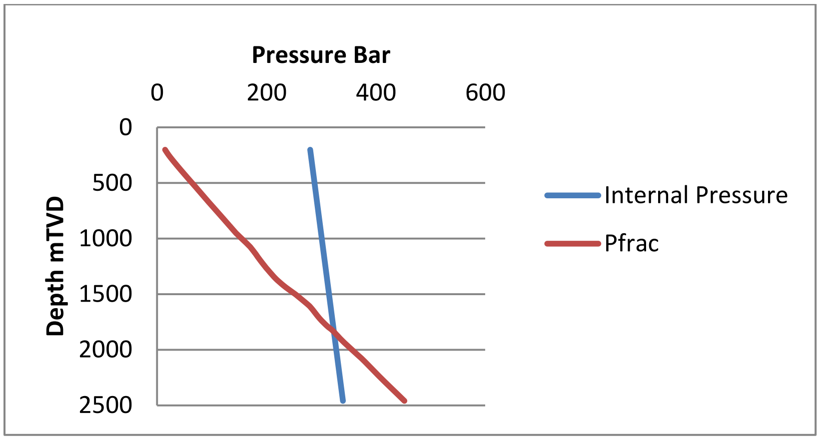


Figure 9: Example of P_{frac} vs. $P_{internal}$

3.2.1.3 Materials

The only requirement is that materials used in well barriers shall withstand the load/environment conditions as long as the well is to be abandoned, and for permanent P&A all eternity. This means that there are no requirements to use a specific material as long as it has the following properties [3]:

1. Impermeable
2. Long term integrity
3. Non shrinking
4. Ductile (non brittle)- able to withstand mechanical loads/impact
5. Resistant to different chemicals/substances (H_2S, CO_2 and hydrocarbons)
6. Wetting, to ensure bonding to steel

3.2.1.4 Leak testing and verification

This is covered in 3.2.3.1.

3.2.1.5 Sidetrack/slot-recovery

It is required that the original wellbore is permanently abandoned before drilling a side-track/slot recovery. If a reservoir section is to be abandoned before drilling to a new target, this implies that primary and secondary barriers are installed.

3.2.1.6 Permanent well barriers

First it is important to clarify the barrier concept. The term has been used to describe general P&A operations earlier in the thesis, without really describing the difference. Confusion may arise between the terms well barrier and well barrier element (WBE). A well barrier consists of one or several well barrier elements. A primary well barrier is the first object that prevents unintentional flow from a source, while the secondary well barrier is the second object that prevents unintentional flow from a source, working as a backup to the primary well barrier. The WBEs create these “objects”.

As mentioned earlier and illustrated in figure 10, NORSOK D-010 states that a permanent well barrier *shall* extend across the full cross section of the well, including all annuli and seal both vertically and horizontally [3]. So an internal cement plug installed inside casing/tubing has to be at a depth interval where there is verified cement with accepted quality on the outside of the casing/tubing, as steel tubular alone is not accepted as a permanent WBE [3].

Other requirements to a permanent well barrier are:

- Elastomer seals used in other WBEs are not accepted as a part of the primary well barriers.
- It is required to verify the presence and pressure integrity of casing cement to evaluate the pressure integrity of this WBE. The cement in annulus alone will not qualify as a WBE across the well, as illustrated in figure 10.

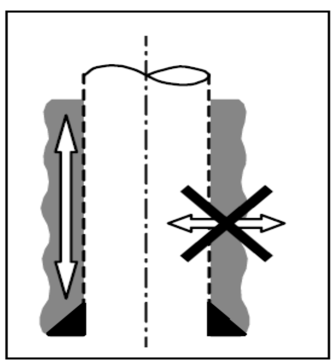


Figure 10: The cement in annulus alone will not qualify as a WBE across the well [3]

- Open hole cement plugs can be used as a well barrier between reservoirs, and should if possible also be used as a primary well barrier.

- Unless leak tested from above prior to setting a possible liner top packer, cement in the liner lap (interval from previous casing shoe to top of liner) shall not be regarded as a permanent WBE.
- There is no requirement to remove downhole equipment as long as the integrity of the well barriers is achieved.
- Control cables and lines installed in areas where permanent well barriers are to be installed, need to be removed as they may create vertical leak paths (described in 2.3.10).
- If the completion tubing is left downhole and the permanent barriers are to be installed inside and around it, reliable methods of installing and verifying the position of the plug need to be established.

3.2.1.7 Special requirements

A special requirement in NORSOK D-010 is for the case where we have multiple reservoirs/perforations located within the same pressure regime. Here the reservoirs can be defined as one reservoir. Figure 11 [3] illustrates this.

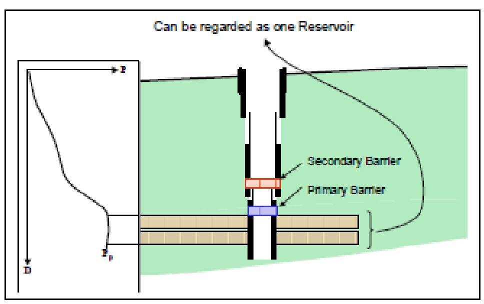


Figure 11: Requirement for different reservoirs under same pressure regime [3]

3.2.2 Well barrier schematics

Well barrier schematics (WBSs) are a practical method developed to illustrate the primary and secondary well barriers for different scenarios in a well. It is important to note that these WBSs are guidelines (should), and NORSOK D-010 states that own WBSs should be made by operators for actual situations during an activity or operation [3]

For permanent P&A operations, four typical scenarios are listed with illustrations in NORSOK D-010. Figure 12 [3] shows the different WBSs (comments found in NORSOK D-010 are not included), and short descriptions of the different scenarios will follow:

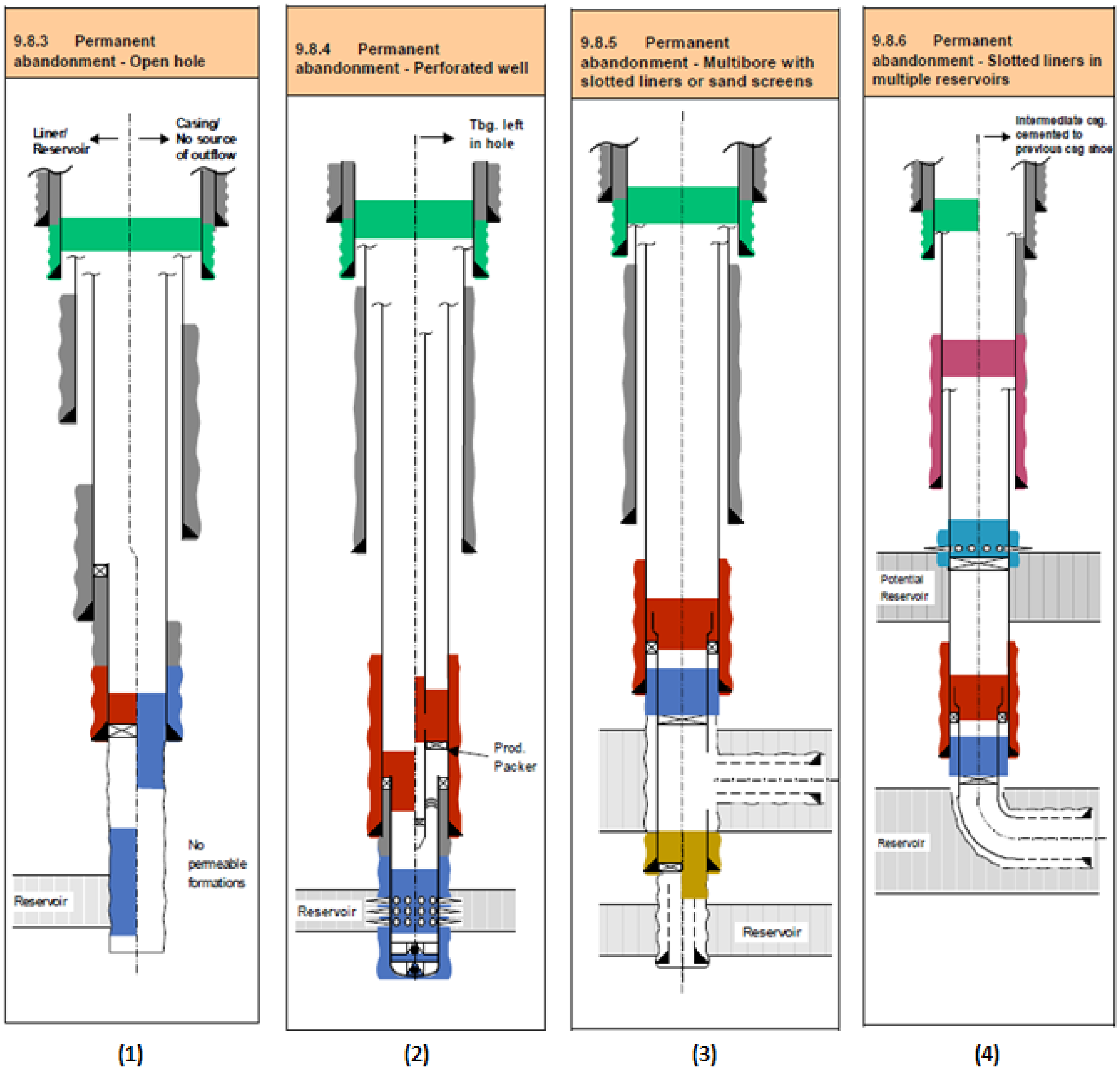


Figure 12: Four different WBSs for permanent P&A [3]

1) Permanent abandonment-Open Hole

The WBS (1) in figure 12 illustrates the scenario for open hole P&A, with casing or liner used. It shows the primary (blue) and secondary (red) well barrier, and an open hole to surface well barrier (green). The WBS also show how casing is cut to allow full access over the full cross sectional area for the surface well barrier.

2) Permanent abandonment- Perforated well

The WBS (2) in figure 12 illustrates the scenario for a perforated well, both with production tubing pulled or left in hole. As in the previous example, primary, secondary and surface well barriers are all illustrated.

3) Permanent abandonment- Multibore with slotted liners or sand screens

The WBS (3) in figure 12 illustrates the scenario for P&A of wells with several reservoirs. This scenario is more complex than the previous two examples. Here there are two separate reservoirs with different pressure regimes. A well barrier is set between the two reservoirs (yellow) as the primary well barrier for the deepest reservoir. Further up, a primary (blue) and secondary (red) well barrier is set for the shallower reservoir. This means that there is only one barrier set against the deep reservoir. The clue in this case is that the primary barrier for the shallow reservoir, can act as a secondary barrier for the deep reservoir if it is designed to take the differential pressures from both reservoirs [3]. This eliminates the need to set two barriers against each reservoir in all situations.

4) Permanent abandonment- Slotted liners in multiple reservoirs

The WBS (4) in figure 12 illustrates the scenario for P&A of wells with several reservoirs, but the difference from (3) is that the reservoirs are spread further apart with two well barriers set against each reservoir. The reason for this is that the formation fracture strength above the shallow reservoir is not sufficient to withstand the internal pressure caused by the deep reservoir, thus the primary barrier here cannot act as a secondary barrier for the deep reservoir. The deep reservoir has one primary (blue) and one secondary (red) well barrier installed, while the shallow reservoir also has a primary (light blue) and secondary (pink) well barrier installed. This scenario is similar to the wells found on Statfjord A (figure 7). The WBS also illustrates two different scenarios, one where the intermediate (third) casing is cemented into the previous casing, and one where the cement does not reach the previous casing shoe. As we see from the WBS, there is no need for a surface barrier in the case where the intermediate casing is cemented all the way into previous casing; since there is no open annulus to surface (the secondary well barrier for the shallow reservoir also acts as the open hole to surface well barrier for this case).

3.2.3 Well barrier elements acceptance criteria

For the WBEs to be accepted as a part of a well barrier, several criteria need to be met, known as well barrier elements acceptance criteria (WBEAC). The area of interest for P&A is the WBEAC for casing, casing cement and the cement plug (the WBEAC for casing will not be covered as this is more important for initial well design).

3.2.3.1 Cement plug

Even though NORSOK D-010 states no specific materials for the use in well barriers (section 3.2.1.3), the WBEAC for a plugs used as permanent well barrier are cement plugs. Table 2 [3] is taken from NORSOK D-010 and describe the acceptance criteria for a cement plug. The table is quite comprehensive, but the most important criteria to highlight are in relation to design and verification. These are:

- Design
    - The plug length shall be 100m MD. If the plug is set inside a casing and with a mechanical plug as foundation, the minimum length is 50m MD.
    - The plug shall extend minimum 50m MD above any source of inflow/leakage point. If a plug is installed in transition from open hole to casing it should extend at least 50m MD below casing shoe
- Verification
    - Cased hole plugs should be tested either in the direction of flow or from above

- The installation of the plug shall be verified through documentation of job performance using records from cement operation (volumes pumped, returns, etc.)
- For an open hole plug, its position shall be verified by tagging or other measures to confirm depth of the firm plug. An open hole plug cannot be pressure tested due to possible formation fracturing.
- A cased hole plug shall be verified with tagging, or other measure as for openhole plug. In addition is shall be pressure tested, with two requirements: a) pressure tested 70bar above estimated formation strength below casing/potential leak path (35bar for surface plugs), b) not exceed casing pressure test.

  If a tagged and pressure tested mechanical plug is used as foundation, the cement plug does not have to be verified (impossible to verify if it is the mechanical foundation or the plug that holds).

Features	Acceptance criteria	See
A. Description	The element consists of cement in solid state that forms a plug in the wellbore.	
B. Function	The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.	
C. Design, construction and selection	1. A design and installation specification (cementing program) shall be issued for each cement plug installation. 2. The properties of the set cement plug shall be capable to provide lasting zonal isolation . 3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole 5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads. 6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole. 7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD. 8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe. 9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.	API Standard 10A Class 'G'
D. Initial verification	1. Cased hole plugs should be tested either in the direction of flow or from above. 2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. 3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.). 4. Its position shall be verified, by means of: **Plug type** — **Verification** Open hole — Tagging, or measure to confirm depth of firm plug. Cased hole — Tagging, or measure to confirm depth of firm plug Pressure test, which shall a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.	
E. Use	Ageing test may be required to document long term integrity.	
F. Monitoring	For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.	
G. Failure modes	Non-compliance with above mentioned requirements and the following: a. Loss or gain in fluid column above plug. b. Pressure build-up in a conduit which should be protected by the plug.	

Table 2: Acceptance criteria for cement plug [3]

Additional information about WBEAC;

- If other materials than cement are used, a separate WBEAC shall be made
- A cement plug installed using a pressure tested mechanical plug as foundation should be verified by documenting the strength development of a sample slurry subjected to an ultrasonic compressive strength analysis, or testing the cement under temperature and/or pressure representative for the well it is to be installed

3.2.3.2 Casing cement

With regards to TOC, it is required that this is verified through logs or using operational records like volumes pumped, returns during cementation, etc. The cement quality shall be verified through formation integrity test (information often missing from when casing shoe was drilled out), or alternatively exposing the cement column for differential pressures (acceptance criteria and verification requirements shall be defined).

3.2.4 General P&A design

According to NORSOK D-010, the following information should be known prior to designing the well barriers and P&A program;

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

NORSOK D-010 also mentions that the design of well barriers consisting of cement should account for uncertainties such as;

- Cement placement techniques
- Minimum volumes required to mix a homogenous slurry
- Surface volume control
- Pump efficiency and parameters
- Fluid contamination
- Cement shrinkage

3.2.5 Removing equipment above seabed

This area has been covered earlier in section 2.2.4, but in short NORSOK D-010 states that;

- For permanent P&A, the wellhead and following casing strings are required to be removed. No parts of the well shall ever protrude the seabed.
- The cutting depth should be 5 m below the seabed, but should be considered in each case based on local conditions around the well.
- Use of explosives are allowed to cut casing if measures are implemented which reduces the risk to the surrounding environment to the same level as other ways of cutting casing.
- All obstructions from drilling and well activities shall be removed from the seabed

3.2.6 Temporary abandonment

This is not the scope of the thesis, but it is important to point out that there is no requirement or guideline in NORSOK D-010 that mention the duration a well can be temporary abandoned. This makes it easy to postpone permanent P&A jobs of wells, and as mentioned 2.3.12, this can lead to an unnecessary wave of wells needing to be permanent P&A in the future.

3.3 Guidelines for the suspension and abandonment of wells (UK Continental Shelf)

The fourth issue of this guideline was published by *Oil and Gas UK* in 2012. It is an independent document made for P&A on UK sector. Compared with the P&A section in NORSOK D-010, this is a far more comprehensive document on 49 pages. In the foreword of the guidelines, some important statements are [11]:

- *The guidelines have been prepared to steer well-operators on the considerations that need to be taken when suspending operations in a well for a limited period of time and when finally abandoning a well.*
- *The guidelines provide minimum criteria to ensure full and adequate isolation of formation fluids both within the wellbore and from the surface or seabed.*
- *The intent of these guidelines is to provide the framework for the decision-making process that should accompany any well suspension and abandonment activity.*
- *It is anticipated that a well-operator will wish to develop its own standards and procedures which can be applied simply and effectively, to achieve an adequate standard of isolation.*
- *It is recognized that the key to a simple temporary or permanent abandonment often lies with the soundness of the initial well design and effectiveness of the primary casing cementations. The benefits of successful cementation should lead to an easier suspension or abandonment.*

Further it is stated that guidelines are made to help the operators comply with the UK legislation, which is the *The Offshore Installation and Wells (Design and Construction, etc) Regulations* [12] from 1996. There are three regulations, 13, 15 and 16, relevant to P&A. Especially 13 and 15 are important, stating that:

(13) *The well-operator shall ensure that a well is so (…) suspended and abandoned that-*

a) so far as is reasonably practicable, there can be no unplanned escape of fluids from the well; and *b) risk to health and safety of persons from it or anything in it, or in strata to which it is connected, are as low as is reasonably practicable.*

(15) *The well-operator shall ensure that a well is so designed and constructed that, so far as is reasonable practicable-*

a) it can be suspended or abandoned in a safe manner; and

b) after its suspension and abandonment there can be no unplanned escape of fluids from it or from the reservoir which it led.

It is important to note that the guideline recognize the importance of initial well design taking future P&A into account as a key to simple abandonment, and have included this in the foreword. In addition regulation 15 requires that a well is designed to ensure safe future abandonment.

The structure of the UK guidelines is somewhat different from NORSOK D-010, and this will be seen in the analysis. But in short this part will cover;

- Permanent well barriers
- Verification of permanent well barriers
- Special considerations

3.3.1 Permanent Well Barriers

3.3.1.1 Number of well barriers

The guideline states that that all distinct permeable zones should be isolated, both from each other and from surface or seabed with a minimum of one permanent barrier. A distinct permeable zone is defined as [11] *a group of permeable zones that were originally within the same pressure regime, and where uncontrolled flow between subzones can be shown to be acceptable. For examples where:*

1. *It will not create a change in pressure control requirements; and*
2. *It will not have an adverse effect on reservoir management; and*

3. *It will not result in "contamination" of the fluids in one of the subzones i.e. freshwater*

Further, it is required to have two permanent barriers if a permeable zone is hydrocarbon-bearing, or overpressured and water-bearing. Permeable zones are defined as any zones where there is a possibility of fluid movement when differential pressure is applied, with a formation being defined as hydrocarbon-bearing if moveable hydrocarbons are present or is likely to be in the future. Overpressured zones are defined as permeable zones where the pressure is in excess of the hydrostatic pressure gradient in the area of interest [11]. Figure 13 [11] is an overview over a permanent barrier, including all the barrier elements (orange boxes) and recommended best practices (blue boxes).

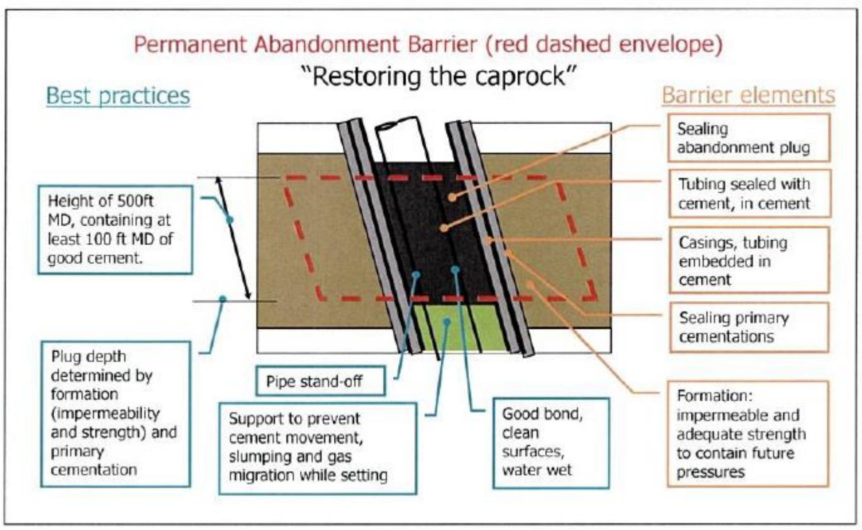


Figure 13: Permanent barrier with its barrier elements and best practices. The red dashed line is the barrier envelope to restore the caprock [11]

3.3.1.2 Barrier position

The UK guideline states that the first barrier should be set across or above the highest point of potential inflow, defined as the shallowest of top permeable zone or top perforation, or as close as reasonably possible. If installed inside casing or liner it should be lapped by annular cement. The shallowest depth a barrier can be set is determined by the formation fracture pressure at the base of the barrier. As in NORSOK D-010, the potential internal pressure cannot be in excess of this [11] (see Section 3.2.1.2 and figure 9).

If a second barrier is required, this works as a backup to the first barrier, with the same considerations as the first barrier (as explained above). It is also important to note that the second barrier for deeper permeable zone can act as a primary barrier for shallower zones. These general requirements are illustrated in figure 14 [11].

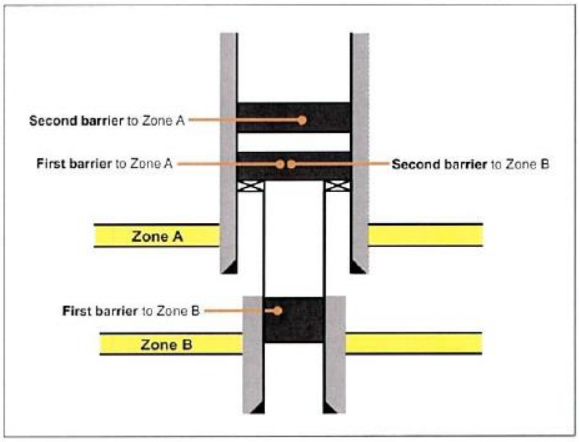


Figure 14: General requirements for P&A [11]

Figure 15 [11] give an overview over general requirements for a different scenario. The difference from the scenario in figure 14 is that no barriers are shared; with all three zones having two separate barriers. This is because caprock L does not have the formation strength to withstand the anticipated pressure for the main reservoir (Zone C), while caprock K does not have the formation strength to withstand the anticipated pressure from sandstone B.

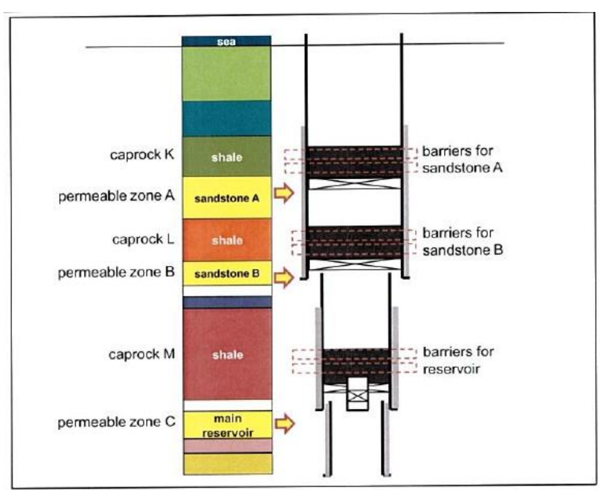


Figure 15: Example of geological setting determining barrier position [11]

3.3.1.3 Barrier length

For barrier length the UK guideline states:

- A barrier of at least 100ft (~30,5m)MD of good cement is recommended
- Generally, a 500ft (~152,5m) MD barrier should be installed
- No specific relation between mechanical foundation and length mentioned
- The top of the first barrier should extend at least 100ftMD above the highest point of potential inflow
- If two distinct permeable zones are less than 100ft apart, a 100ft MD column of good cement below the base of the shallower zone would suffice if practical
- If barrier is set in casing/liner, at least 100ft MD of good cement in annulus adjacent to the internal plug is required (full cross-sectional area)
- If one long combined barrier replaces two separate barriers, a column of 200ft MD good cement (~62m) is recommended. Generally an 800ft MD (~244m) barrier is set for a combination solution.

When talking about a barrier being 100ft MD of good cement, the author interprets this as not having to be 100ft of continuous cement. That is why "best practice" is setting a 500ft plug (if single barriers), with at least 100ft of this being good cement. Figure 16 [11] is a summary of the length requirements.

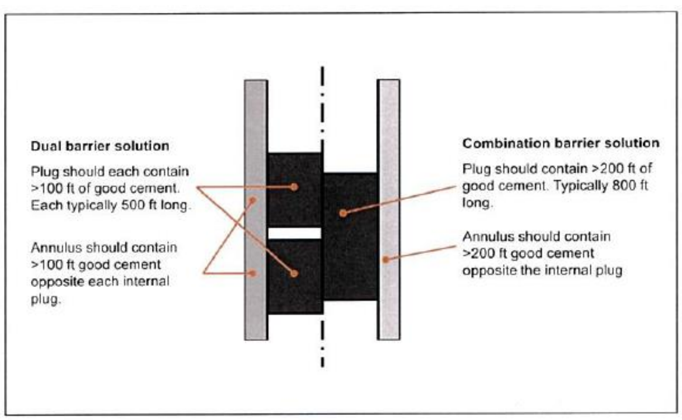


Figure 16: Length requirements [11]

3.3.1.4 Requirements to openhole P&A

For openhole P&A three different scenarios are described. The general requirements described in the previous sections do apply for openhole P&A, but there are differences in how to apply these depending on the downhole conditions. All zones described are permeable zones needing two permanent barriers.

The first scenario is illustrated in figure 17 [11]. Here the barriers against zone A are set in the cased hole. This is possible since the potential internal pressure does not exceed the casing shoe fracture pressure. Two different solutions are described, one using dual barriers, and one with a combination barrier is applied.

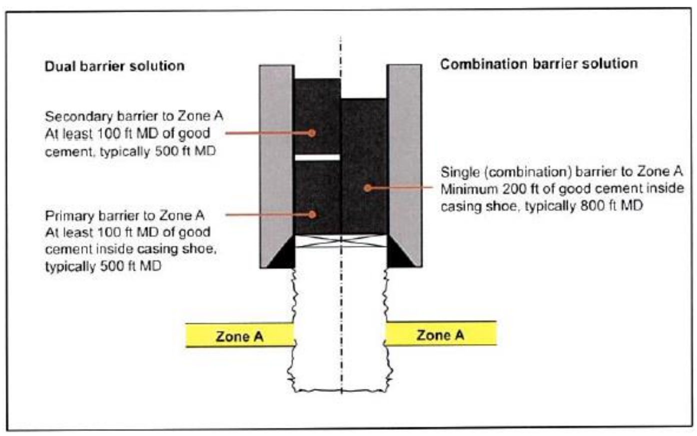


Figure 17: Openhole P&A, potential internal pressure does not exceed casing shoe fracture pressure [11]

The next scenario is illustrated in figure 18 [11]. Here there are two different permeable zones belonging to different pressure regimes. In general, each zone would need two permanent barriers each, but since the potential internal pressure from zone A does not exceed the casing shoe fracture pressure, one permanent barrier between the zones is sufficient. Further, two permanent barriers are installed inside the casing, either a dual barrier solution, or with a combination barrier.

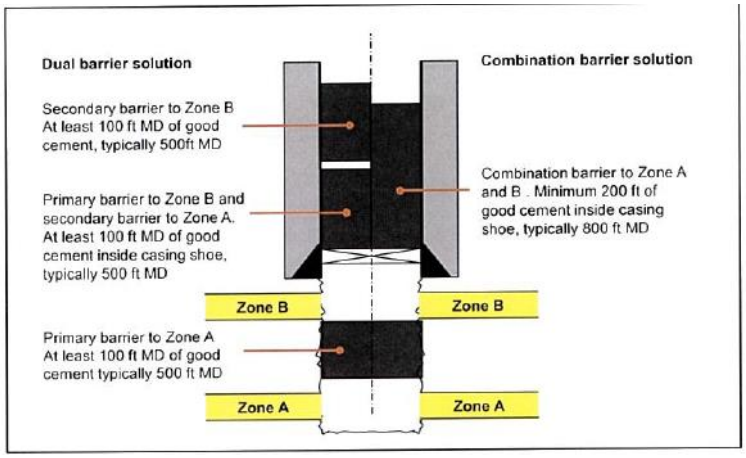


Figure 18: Openhole P&A, two different permeable zones belonging to different pressure regimes [11]

The last scenario for openhole P&A is illustrated in figure 19 [11]. Here the potential internal pressure from permeable zone A does exceed the fracture pressure somewhere in the openhole. In this case there should be set two permanent barriers in the openhole section, either a dual solution or combination solution, with the potential internal pressure not exceeding the fracture pressure at the base of the barriers. In addition, there should be installed a permanent barrier somewhere in the casing to fully seal the open hole section (same as surface barrier in NORSOK).

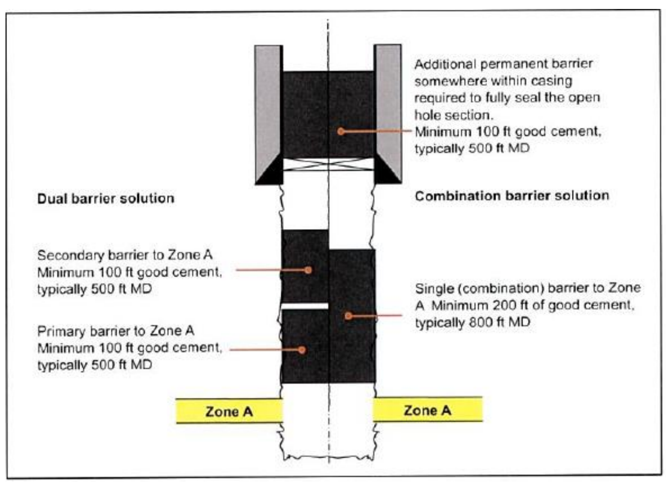


Figure 19: Openhole P&A, potential internal pressure does exceed fracture pressure somewhere in openhole [11]

3.3.1.5. Requirements to cased hole P&A

According to the guideline, cemented casing does not constitute a permanent barrier alone as there is a potential for lateral flow into or out of the wellbore. This is because a poor cement job can result in fluid migration if the casing starts to leak, as seen in figure 20 [11]. But, as long as there is “sufficient confidence” in the quality of the annulus cement, cemented casing is regarded as a barrier against vertical flow [11].

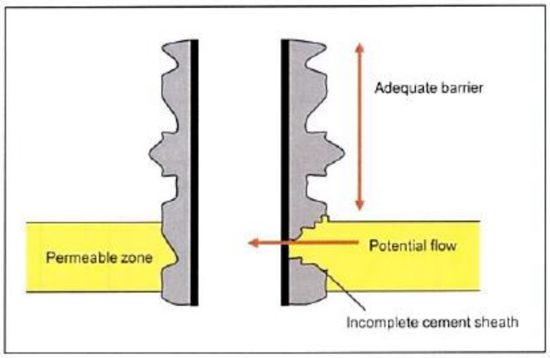


Figure 20: Cemented casing is not a permanent barrier with regards to lateral flow [11]

TOC in annulus can be established either by different logging tools or by recorded parameters during the original cement job (i.e. measured volumes, differential pressure, etc.). If the latter method for verification is used, a longer cement column in annulus is required to allow for uncertainty. The cement column in annulus should in this case be 1000 ft (305m) above the base of the primary permanent barrier, and is considered adequate for a dual barrier or combination barrier solution. The length of the column may be reduced or increased depending on the confidence in TOC on a well to well basis [11].

Figure 21 [11] gives an overview over a cased hole abandonment. The normal requirement is that formations belonging to different pressure regimes should be separated by one permanent barrier. But as seen from the figure, there are no installed barriers between the different zones since cross-flow is deemed acceptable for this scenario, e.g. same pressure regime. The annulus cement is illustrated with two different scenarios. One where TOC has been determined by differential pressure or monitored volumes measured during the original cement job (1000ft to allow for uncertainty), and the other for TOC verified by logs (normal requirements, 100ft of verified annular cement for each barrier). The height requirements are described in the previous paragraph. The last permanent barrier is for the shallow permeable zones (not overpressured or hydrocarbon bearing), and also works as the surface barrier [11].

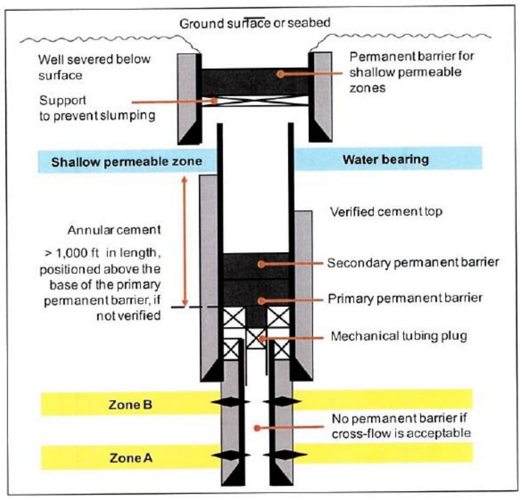


Figure 21: General illustration of cased hole P&A [11]

In the UK guideline an own Appendix is dedicated to barrier integrity, where several potential issues and mitigation actions are described in compliance with good industry practice.

3.3.2 Barrier verification

The UK guideline illustrates how permanent barriers should be verified to ensure that it is installed at the required depth and have the required sealing capability.

3.3.2.1 Cement barrier

A cement plug installed inside casing or in openhole should be verified by the following [11]:

- Parameters like volumes pumped, returns during cementation, etc. (this information should be documented).
- The strength development of the cement slurry through pre-job testing with representative downhole temperature and pressure. Surface samples taken during the job may also be used as an indicator, but its inability to replicate downhole pressure and temperature will have a big impact, so this should be treated with caution
- Barrier position should be verified by tagging or other measurements to confirm the depth of the plug
- In openhole the barrier should be verified entirely by a weight test:
  - On drillpipe this is typically 10 to 15 klbs (4.5-6.8 tons) (weight can be limited if using e.g. wireline or CT)

- In cased hole, the barrier should be verified by a pressure test or inflow test:
  - The pressure test should be a minimum 500psi (~35 bar) above the injection pressure below the barrier (e.g. into perforations or open formation below the casing shoe). It should not exceed the casing strength minus wear allowance or damage primary casing cement
  - Inflow test should be similar to the maximum differential pressure the barrier will experience after abandonment
- If a tagged and pressure tested mechanical plug or previous cement plug is used as foundation in cased hole, pressure testing and tagging of the barrier may not be necessary as it is impossible to determine if it is the mechanical plug/previous cement or the installed barrier that is sealing.

3.3.2.2 Casing cement

TOC should be verified by [11]:

- Logs
- Parameters from the cement operation (volume pumped, returns during cementation, differential pressure, etc.)

The sealing capability should be assessed with supporting evidence which may include:

- Logs
- Absence of annulus pressure during the life cycle of the well
- The leakoff test when casing shoe was drilled out
- Absence of anomalies during cement job
- Centralization, washouts, lead/tail slurry, annulus pressures field experience, excess should be considered

Also provided in the guideline are a set of tables that are aimed to help with methods to verify cement plugs and annulus cement. These cover both the verification of primary and secondary barrier (dual barrier), and for a combination barrier (found in Appendix A).

3.3.3 Special considerations for P&A

The UK guideline includes several special considerations for P&A, being a lot more thorough than NORSOK D-010. Some of these will be described in this section.

3.3.3.1 Well design

In the UK legislations [12], there is a regulation that clearly states that a well is to be designed and constructed so it can be suspended or abandoned in a safe manner in the future. In addition to this, it is clearly stated in the guideline that the key to simple P&A lies with the quality of the initial well design and primary casing cementations. Further it states that the operators must consider P&A as a part of the well design and modification [11].

3.3.3.2 Sidetracking or other partial abandonment

The plug used as the primary barrier to abandon the original wellbore has the same requirements as explained in 3.3.1. But the guideline also states that it is recognized that a temporary barrier can be used for these operations as long as they do not compromise the future P&A operation. If a kick-off plug is used (cement used as foundation to kick-off the well, typically done in open-hole without using a whipstock), the remaining cement after kick-off should meet the minimum requirements of a permanent barrier [11].

3.3.3.3 High angle and horizontal wells (>70°)

P&A of horizontal wells are in principle the same as for other wells. The only difference is that it is more difficult to achieve satisfactory isolation. The main issue pointed out in the guideline is when there is more than one distinct permeable zone, the completion design should consider future abandonment, with the goal being zonal isolation between the zones. If this is done in a good way, the P&A operation can go smoothly. It is further pointed out that if an uncemented production liner is used as completion through several permeable zones, zonal isolation should be attempted, but that the significant difficulties in achieving this in high inclination well is recognized. [11].

3.3.3.4 Multilaterals

With regards to multilaterals, considerations stated in the guideline are:

- Future P&A in mind when designing the well, can be very difficult to regain access to original wellbore in some cases

- Can be different pressure regimes in different branches
- Cementing of annulus above the laterals (since barriers probably are installed here)

3.3.3.5 Liner laps

As for all barriers, 100ft of good cement should be assured in the liner lap in addition to the casing cement if barriers are installed here, see figure 22 [11].

It is common practice that the liner top packer is set immediately after the liner cement job, and thus the liner lap and packer are normally tested together, making it impossible to know whether it is the cement or packer that is holding pressure. As the liner packer is not considered a permanent barrier, the only way to use the cement in the liner lap as a barrier is if this was pressure tested and verified before setting the packer [11].

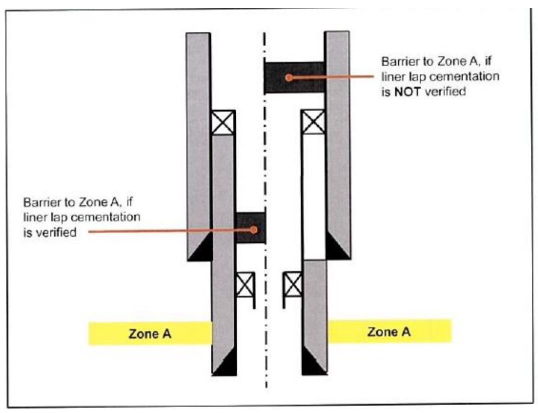


Figure 22: Liner lap cementation [11]

3.3.3.6 Removal of downhole equipment

Not a requirement as long as the isolation outlined in the guidelines are achieved [11].

3.3.3.7 Control lines, ESP cables, gauge cables

These should not be part of the permanent barriers as they form potential leak paths.

3.3.3.8 Through-tubing P&A

If well completions are left in the hole and permanent barriers are to be installed through and around the tubular, the guideline states that reliable methods and procedures for barrier placement and verification should be established. For determining TOC in both tubing and annulus no accurate method is available, but a method of tagging combined with quality control through e.g. measurements of cement job is mentioned. [11]. Figure 23 [11] show an example of through-tubing P&A, where a combination barrier is used, and punched tubing (induced holes in tubing followed with cement squeezing) is used to establishing barriers in the A-annulus. Since there are no logs that can log through multiple strings, 1000ft MD of cement is recommended in B-annulus if verification is based on other information that logs (see section 3.3.1.5).

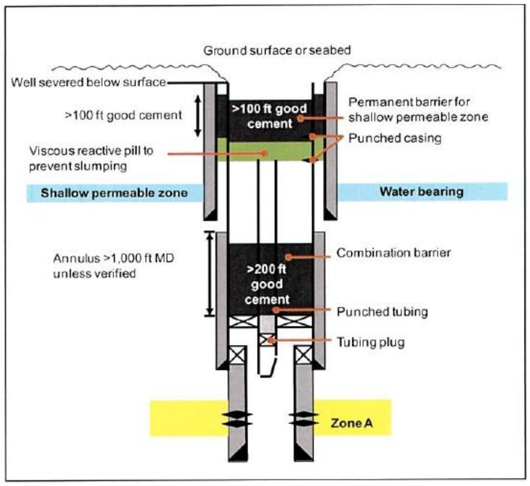


Figure 23: Example of through tubing P&A [11]

3.3.3.9 Sealing formations

This topic was mentioned in chapter 2.3.9. Formations like shale are movable as a result of different stress regimes in formations, and in some cases the shale can move onto casings and seal where cement is missing. If the formation is verified as adequate to prevent flow from relevant formations at anticipated future pressures, then this is acceptable as a replacement for cement. Further, the guidelines provide requirements to the qualification of a sealing formation:

1. Proof that the formation has required fracture strength to withstand anticipated future internal pressures.
2. Verification that the lengths of the formation seal exceeds 100ft for each barrier; accomplished from bond log response that is equivalent to that of good cement. Each well requires two independent logging tools to be run to confirm the bonding between casing and formation with no channels. Interpretation should be performed by a qualified and trained cement evaluation log specialist and documented.

3. Validation that the log response can be interpreted as not leaking at the anticipated future pressures. This can be achieved by pressure testing between 100ft spaced perforations.

The qualification process should be documented.

3.3.3.10 Removal of subsea equipment

Redundant subsea equipment left behind must not present a hazard to other users of the sea. The wellhead and all casing strings should be removed to accommodate fishing activities in the area after permanent abandonment. The recommended minimum depth of wellhead and casing removal is 10ft (~3m), but this should be evaluated from well to well taking into local conditions. Further, all subsea equipment and debris should be removed where practical and a seabed clearance certificate issued. The certificate should clearly identify anything left behind at the site, with a minimum recommended radius of search being 70m from the well. For large concrete structures permanently remaining at the seabed, no casing strings should extend above the remaining structure [11].

3.3.3.11 Data gathering prior to P&A job

The information that should be gathered as a basis for the P&A design is identical to NORSOK D-010, see section 3.2.4.1

3.3.4 Temporary abandonment

There are no specific requirements to the duration of temporary abandonment. But proposed abandonments that are planned for longer than 18 months should be in compliance with *Department of Energy & Climate Change* requirements, and be justified by performing assessments to demonstrate that the barriers will maintain their integrity for the whole duration of abandonment [11].

The guideline also states that operators should consider physical inspections schemes for temporary abandonment, with the frequency of inspection being justified and should take into account well status, subsurface conditions and marine activity.

3.3.5 Materials

The requirements for material used in P&A operations are more or less identical to those in NORSOK D-010 (see 3.2.1.3), as well as using cement as reference plugging material. As in NORSOK D-010, the use of alternative materials is not excluded as long as they meet the requirements. The only difference is that a separate guideline have been made for the qualification of barrier materials in UK, called the *Guidelines on qualification of materials for the suspension and abandonment of wells* (Oil & Gas UK). This was made to provide a reference for operators on the qualification of materials used in P&A operations at the UKCS. This guideline will not be covered in more detail, but its contents are mainly [13]:

- General consideration for qualification of new technology
- Functional requirements of permanent barriers
- Operating conditions
- Potential functional failure modes and root causes
- Material types
- Experimental work plan
- Experimental work plans for specific materials

3.3.6 P&A Categorizing

One of the more interesting features in the UK guideline [11] is the "P&A Code" system. This was introduced to indicate a work scope of P&A operations. It is an effective way of categorizing operations, and is used for high level cost estimation and benchmarking.

The scope of a P&A operation is represented by a certain code. The system presented in the guideline consist of two letters indicating the well location, followed by three digits representing the complexity of 3 different phases of P&A, an example is **SS 2-3-2**.

The two letters define the actual physical location of a well. These are [11]:

- **PL-** Platform well
- **SS-** Subsea well
- **LA-**land well

The three digits represent the complexity of three defined distinct P&A phases. These phases give a clear and effective overview over a P&A operation [11].

- 1st (from left to right) digit in the P&A code represent phase 1 of a P&A operation- Reservoir abandonment
  - This is the part of a P&A operation where the primary and secondary barriers are installed to isolate all reservoir zones (producing or injection). The production tubing (upper completion) can be either left in hole, partly or fully retrieved. This phase is complete when the reservoir is fully isolated in compliance with the requirements.
- 2nd digit represent phase 2 of a P&A operation- Intermediate abandonment
  - This is the phase where typically casing is pulled (or milled), intermediate barriers to other permeable zones are set, and surface barrier is installed. The tubing may be retrieved if not done in phase 1. This phase is completed when all required barriers are set.
- 3rd digit represent phase 3 of a P&A operation- Wellhead and Conductor removal
  - As nothing should ever protrude the seabed, the conductor and following casings need to be cut at some depth (recommended minimum depth in the guideline are 10ft) below the seabed, and removed together with the wellhead.

A digit (0 to 4) is chosen for each phase as a way to describe the complexity level of a P&A operation. The guideline defines these digits as:

O: No work is required- the P&A work for a given phase may already have been completed

1: Simple rigless P&A work- using wireline, pumping, crane, jacks. For subsea wells a light well intervention vessels can typically be used, with no riser needed (RLWI).

2: Complex rigless P&A work- using coiled tubing or hydraulic workover unit, wireline, pumping, crane, jacks. For subsea wells, well intervention vessels with riser needed if used.

3: Simple rig-based abandonment- the well abandonment require retrieval of tubing and casing using a drilling rig

4: Complex rig-based abandonment- the well may have poor access and poor cement requiring retrieval of tubing and casing, milling and remedial cement operations

The P&A code can in a simple and effective way be used to record the P&A complexity and methodology for all three phases. Tables 3, 4 and 5 are examples on how to use this system.

Table 3 shows a classification of a P&A operation for a platform well, with P&A code **PL 4-3-0**. Here the reservoir abandonment has a digit number 4, which reflect the highest complexity code for P&A. The barrier intervals can be in need of cement remedial, which may require milling. Later the drilling rig is used to pull tubing and place shallow barriers. The conductor and wellhead will not me removed at this time, but later when field decommissioning will commence.

Platform Well			**Abandonment complexity**				
			Type 0 No work required	**Type 1** Simple rigless	**Type 2** Complex rigless	**Type 3** Simple rig-based	**Type 4** Complex rig-based
Phase	1	Reservoir abandonment					x
	2	Intermediate abandonment				x	
	3	Wellhead & conductor removal	x				

Table 3: Example of P&A classification for a platform P&A operation

Table 4 shows a P&A classification for a subsea well, with P&A code **SS 0-1-1**. Here the well has already been abandoned across the reservoir, and the tubing removed. A RLWI is then used to install the surface barrier (assume no shallow formations needing barriers), and to complete the P&A operations by removing the wellhead. This is possible with technology presented in chapter 4.

Subsea well			**Abandonment complexity**				
			Type 0 No work required	**Type 1** Simple rigless	**Type 2** Complex rigless	**Type 3** Simple rig-based	**Type 4** Complex rig-based
Phase	1	Reservoir abandonment	x				
	2	Intermediate abandonment		x			
	3	Wellhead & conductor removal		x			

Table 4: Example of P&A classification for a subsea P&A operation

Table 5 shows P&A classification for multiple wells located in a subsea field. In this situation no single P&A code is applicable, but it shows how this methodology can be used to summarize the number of wells that need to be abandoned with a particular method for each phase. For this case, 25 subsea wells are to be permanently abandoned. 5 wells has already been abandoned across the reservoir section, with three of these fully abandoned. 20 wells still need to be abandoned across the reservoir, where 3 need a complex remedial operation using a semi-sub. 22 of the wells need tubing to be pulled and intermediate barriers to be set using a semi-sub. Surface barriers are also set using the drilling rig. In the end all 25 wells need the wellhead and conductor removed using a RLWI.

Subsea field, 25 wells			Abandonment complexity				
			Type 0 No work required	**Type 1** Simple rigless	**Type 2** Complex rigless	**Type 3** Simple rig-based	**Type 4** Complex rig-based
Phase	1	Reservoir abandonment	5		17		3
	2	Intermediate abandonment	3			22	
	3	Wellhead & conductor removal		25			

Table 5: Example of P&A classification for multiple wells

As described above, there is a general description of every digit used to illustrate the complexity of each P&A phase. But in addition one can find a set of tables and associating notes summarizing some of the key factors that will determine the complexity of each phase in the *Guideline on Well Abandonment Cost Estimation* (described more in 3.3.8) [14]. The complexity is determined by assessing the characteristics listed sequentially in the tables. Table 6 (notes not included) is the table that describes phase 1 abandonment. The first characteristic is sustained casing pressure (SCP), relating to failed casing cementation leading to overpressures or hydrocarbons behind casing originating from the reservoir(s), which requires remedial actions. If the well does have SCP, then a "type 4" complex rig operation is needed, giving the P&A code PL-4-x-x for a platform well. If the well does not have SCP then move on to the next characteristic until the type of operation is confirmed. The tables for the other two phases are not included, but structured similarly [14].

Note #	Well Characteristics/Condition at abandonment	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig	**Type 4** Complex rig
1	Sustained Casing Pressure due to hydrocarbons or overpressure	x	x	x	ν
2	Not cemented casing/liner at barrier depths	x	x	x	ν
3	Restricted access to tubing	x	x	ν	0
4	Deep electrical or hydraulic lines present at barrier depth	x	x	ν	0
5	Annular Safety Valve present	x	x	ν	0
6	Packer set above cap rock	x	x	ν	0
7	Site does not allow for CT/HWU pumping operations	x	x	ν	0
8	Multiple reservoirs to be isolated	x	ν	0	0
9	Tubing leak	x	ν	0	0
10	Inclination >60 deg. above packer (difficult for wireline access)	x	ν	0	0
11	Well with good integrity, no limitations	ν	0	0	0

Table 6: Criteria for classifying phase 1 P&A complexity: x-Not feasible, ν-Required. 0- Optional

3.3.7 Categorization of temporary abandoned subsea wells

Another feature included in the UK guideline [11] is a categorizing system to describe the status of temporary abandoned subsea wells. This helps hold track over temporary abandoned wells, and the complexity of future permanent P&A operations. The categorization system is shown in table 7 (the term suspended is used for temporary abandonment), with figure 24 showing an example of a category **2.1** temporary abandonment [11].

Category	Definition
1	The well has been sufficiently suspended that final abandonment only requires removal of the wellhead.
2.1	The well has one annulus uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annulus or placing a separate barrier. This type of well may be abandoned with a drilling rig or a well intervention vessel.
2.2	The well has two annuli uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annuli or placing a separate barrier. This type of well may be abandoned with a drilling rig or a well intervention vessel.
3	The suspended condition of the well is not suitable for full abandonment without significant intervention. Typically, with current technology, the abandonment programme will require a drilling rig to effect the operation.
4	The well has not been categorised into one of the above.

Table 7: Categorization system for temporary abandoned wells [11]

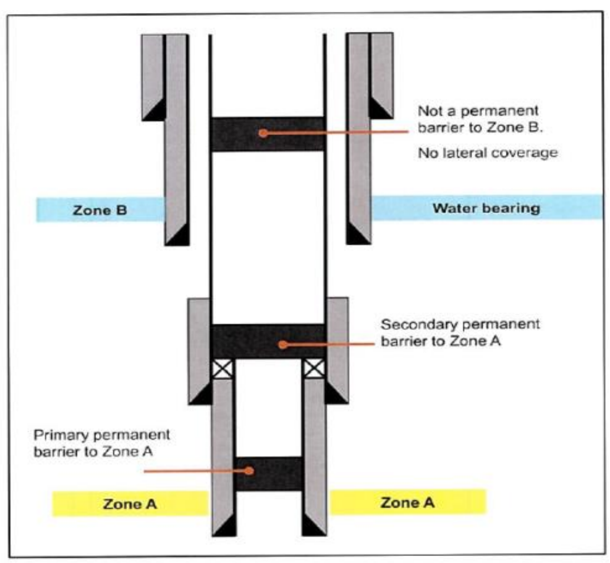


Figure 24: Category 2.1 temporary abandonment [11]

3.3.8 Guideline on Well Abandonment Cost Estimation

Oil & Gas UK early recognized the major impact decommissioning and well abandonment had on the industry. In 2005 a number of workgroups were set up to coordinate future work, notably WG5 for well abandonment. It is this WG5 that prepared the "Guidelines for the Suspension and Abandonment of Wells", and in 2011 the first issue of "Guidelines on Well Abandonment Cost Estimates" was released. This had been development to be consistent with the guidelines "Decommissioning Cost Estimate Guidelines" issued by WG4, and to provide specific guidance on generating cost estimates of P&A operations [14].

The guideline was developed to *provide a simple, auditable and common approach to accounting liability and estimating well abandonment costs*. It was made to outline best practice based on industry experience, and it is anticipated that operators working on UKCS will generate estimates according to the principles and practices described in the guideline. Further, the guideline is aimed for field-range well abandonments, and not at P&A operations relating to exploration/appraisal wells or typical slot recovery operations, but the principles can be used for smaller sized developments [14].

The guideline is quite comprehensive, not everything can be included in the thesis, so the author will try to underline the most important aspects.

3.3.8.1 Cost Estimate Accuracy in relation to P&A proximity

In the guideline it is recognized that the detail and accuracy of estimates has to be more exact as COP (Cessation of Production of field) approaches. In UK, discussions of P&A proposals typically commence with the Department of Energy & Climate Change 2-3 years prior to anticipated COP, leading to the submission of the Decommissioning Programme. Because of this first planning may need to start at least 5 years in advance of COP, and with quite detailed cost estimates. As a first step in the preparation of an estimate, it is necessary to determine the appropriate number/portion of wells within a field that should be included in the analysis of the future P&A activity. Table 8 provides an overview over wells that should be included, and the expected accuracy of the analysis in relation to the decreasing duration before expected COP

[14].

For more than 10 years until expected COP, it is obvious that the accuracy level of the cost estimation is significantly lower than for imminent abandonment (-30% to +50%). According to the guideline, it is recommended that a sample of 10-25% randomly selected wells are chosen and examined according to the methodology described in the next chapter [14].

When expected COP is between 5 and 10 years away, the expected accuracy level should stay more or less constant, with the estimates now based on a sample of 25-50% randomly selected wells [14].

When COP is less than 5 years away, the work scope and associated cost comes to a critical stage. According to the guideline, experience show that an early start of well assessment and planning improves the efficiency of P&A activity significantly. This may allow for early phase 1 and possibly phase 2 abandonment. Being ready through thorough planning years ahead will reduce both the downtime and reduce the associated costs. As seen from the table, it is recommended in the guideline that all wells are examined on this stage, with an expected accuracy of -15% to +30%.

When the P&A operations are imminent, the estimates should be on a conceptual level, with the number and place of permanent barriers indicated, and casing and conductor operations identified. Full well and site details, contract strategies, and spread rates should be a part of the cost estimation, eventually resulting in AFE (Authorization For Expenditure) type cost estimates. AFE cost estimates need a high degree of accuracy, with the characteristics of every individual well needing to be assessed, and because of this not covered in the guideline [14].

Increasing level of accuracy required

Time to COP	Proportion of Wells Required for Review	Approach Required to review the Selected Wells	Expected Accuracy Range
> 10 years	10-25%	Field-view review of representative wells	-30% to +50%
5 to 10 yrs	25-50%	Well-by-well review of sample to define concept design and associated work scope	
< 5yrs	All	Detailed, full, well by well review. Timing of P&A phases may need to be considered	-15% to +30%
Imminent	All	Detailed well by well review of status, integrity, work units required, services cost	-5% to +15%
For AFE	All	AFE estimates are out of the scope of these guidelines	

Table 8: Estimate accuracy relating to proximity to COP

3.3.8.2 Cost Estimate Methodology

A cost estimate process flow is suggested in the guideline. It can be used for every degree of P&A activity, from field-wide use to individual wells [14].

1. Make and maintain a well list that identify all wells/fields and Nominal COP
2. Do a well review as in table 8 and update well list
3. Check if the analysis is adequate enough, acceptability of uncertainty and/or do a risk assessment
4. Define P&A location/phases/P&A complexity of field/wells (see 3.3.6)
5. Determine specific P&A codes (as illustrated in tables 3,4 and 5) and the required type of P&A operation using criteria for classifying the complexity of different phases (example shown in table 6)
6. Use the determined P&A codes in the well list
7. Determine operational durations (explained later)
8. Cost buildup (explained later)
9. Determine the equipment spread required for each P&A phase (what equipment is to be used where)
10. Determine rig rates
11. Calculate cost as a result of duration and rates

12. Define additional costs like cost of mobilization
13. Determine an overall project cost estimate for the wells/fields (seen later)

3.3.8.3 Estimating P&A duration

After assigning P&A codes to the wells, it is necessary to determine likely duration of each P&A phase. Two methods are mentioned in the guideline, one being probabilistic modeling, and the other deterministic modeling.

The guideline states that it is anticipated that the following steps are used to establish P&A duration [14]:

- Define scope for each phase and type, as captured in the P&A codes
- Determine phase durations either by probabilistic modeling or deterministic modeling
- Determine NPT and WOW either by probabilistic modeling or deterministic modeling
- Determine P10, P50, P90 and mean if applicable
- State time build up and assumptions

The operators should use some kind of benchmarking using internal and external data to determine the likely duration of P&A operations. This can lead to a probabilistic modeling using key factors P10, P50, P90 and mean, resulting in determining the most likely outcome of a project and uncertainty. The alternative is using deterministic values for each type and phase [14]. Using a deterministic model gives no room for random variation, making this method significantly less robust than a probabilistic model. An example of estimated duration for the different phases is illustrated in table 9 (subsea well, duration in days).

<table>
<tr><th colspan="3" rowspan="2">Subsea well (Days)</th><th colspan="5">Abandonment complexity</th></tr>
<tr><th>Type 0
No work required</th><th>Type 1
Simple rigless</th><th>Type 2
Complex rigless</th><th>Type 3
Simple rig-based</th><th>Type 4
Complex rig-based</th></tr>
<tr><td rowspan="3">Phase</td><td>1</td><td>Reservoir abandonment</td><td>0</td><td>3</td><td>5</td><td>2</td><td>12</td></tr>
<tr><td>2</td><td>Intermediate abandonment</td><td>0</td><td>3</td><td>6</td><td>6</td><td>10</td></tr>
<tr><td>3</td><td>Wellhead & conductor removal</td><td>0</td><td>1</td><td>3</td><td>2</td><td>8</td></tr>
</table>

Table 9: example of P&A duration for each phase and type

3.3.8.4 Determining P&A phase cost

The cost estimate is found by multiplying expected duration of a given phase and the applicable spread-rate. There are several ways of determining spread cost, but remember that this analysis is often done for future operations years ahead, and will not be mentioned in more detail. Table 10 shows an example of spread costs (non-defined currency) per phase for a subsea installation.

Installation type (nominal cost per day)	Type 1 Simple rigless	Type 2 Complex rigless	Type 3 Simple rig-based	Type 4 Complex rig-based
Subsea	150.000	200.000	300.000	300.000

Table 10: Example of spread cost for different type of P&A work

3.3.8.5 Estimating overall cost for P&A activity

As estimates for duration of each type of P&A operation is found for all phases along with spread cost, a final overall cost estimate can be calculated. Figure 25 explain how this is done. The cost estimate for a specific P&A code is calculated by multiplying duration with spread cost for one well. This is multiplied with the number of wells with the specific P&A code. All cost estimates for every P&A code is added together; with this estimate added with campaign one off cost (e.g. mobilization cost). The final sum represents the total cost estimate for the P&A of the fields/wells, also known as the *Asset Retirement Obligation* (ARO) [14].

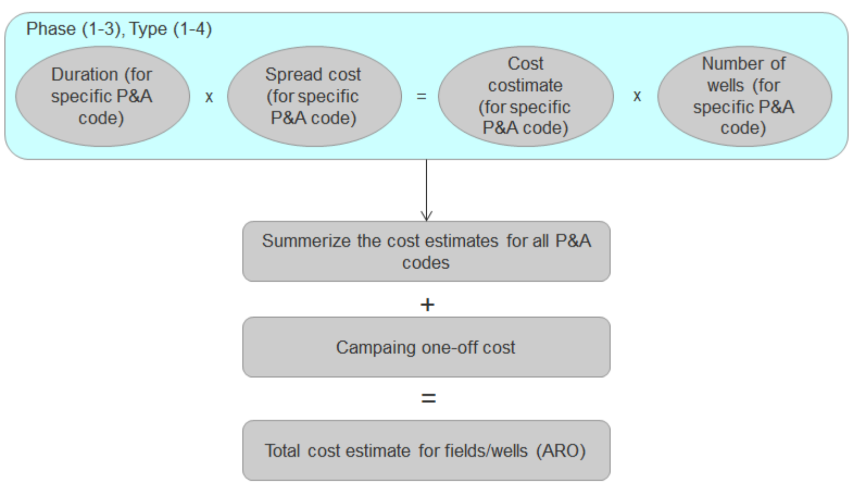


Figure 25: Figure explaining methodology for overall cost estimation for P&A activity

4. Technology

As described in chapter 2, there are several challenges relating to technology. As the situation is now, it will not be economically sustainable for operators to perform P&A operations conventionally. The best way for P&A operations to become more economically viable is through advances in technology. In this chapter several alternative methods of performing the different phases of P&A will be presented. In addition a general presentation of different vessels/rigs that are commonly used for subsea P&A will be described, as the main solution for cost effectiveness for subsea wells is to go from the expensive semi-submersible rigs, to the cheaper LWI vessels. It is important to note that there are several other technological solutions than the ones presented in this thesis, with these being a selection chosen to show how technology can simplify P&A operations

4.1 Vessels used in subsea P&A operations

Statoil divide their vessels and rigs in five categories, illustrated in figure 26 [15]. For P&A purposes, the interesting categories are mainly A, B and C.

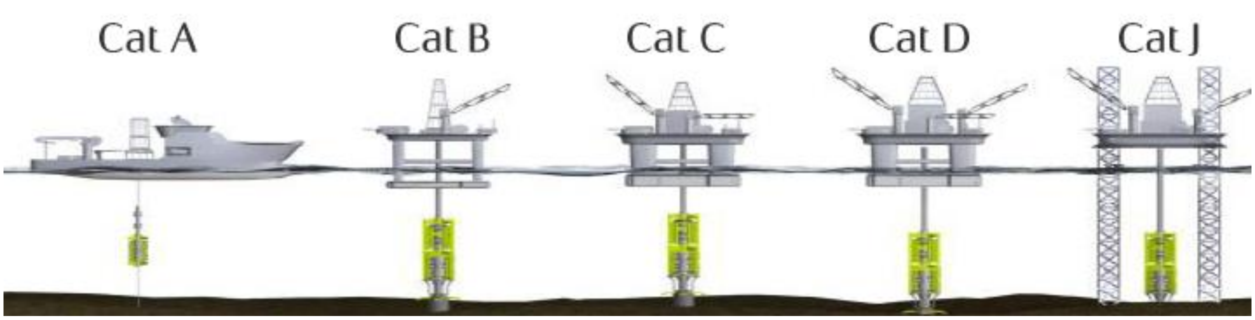


Figure 26: Rig categories [15]

4.1.1 Category A vessel

Statoil's ambition is to achieve an average recovery factor of 55% for their subsea wells, with well intervention being a large contributor in achieving this goal. The use of RLWI, being monohull intervention vessels with no use of riser, started in the early 2000s. The introduction of RLWI instead of using rigs dramatically lowered the intervention cost per well, as shown in figure 27 [16]. As P&A of subsea wells will be a major issue in the future, there is a big interest in how to utilize these RLWI vessels most effectively in P&A operation. The future goal is to perform full permanent abandonment of subsea wells with smaller vessels, and with it eliminating the use of expensive semi-submersibles.

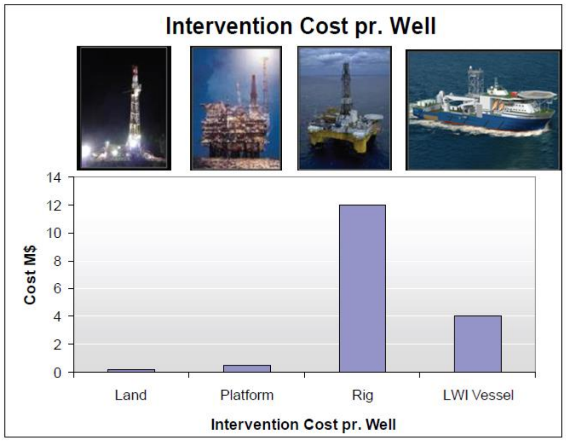


Figure 27: Intervention cost per well comparing vessels [16]

In Statoil, category A vessels are defined as vessels that do not use risers and only perform wireline operations (RLWIs). But there are similar vessels that cannot be defined as typical category A vessel as in Statoil. These intervention vessels are typically somewhere between category A and B, and can perform several operations the typical category A vessel cannot, most notably the use of rigid risers and thereby coiled tubing. One example is from a company called *Helix Energy Solutions Group* (Helixesg), which are one of the leading well intervention companies in the world. Helix classifies their fleet of LWIs in three different categories [17]:

- ***Cat A***: Identical to the definition used in Statoil. Only use of wireline deployed via a Subsea Intervention Lubricator (SIL)
- ***Cat A+***: Wireline and CT via SIL and sub 7" riser. Unable to work on full bore 7" which limit what can be done. Systems required to handle motions at sea are quite complex.
- ***Cat A++:*** Wireline and CT via 7" riser. Can work through full 7" wellbore, but the price is quite high compared to cat A and A+. High complexity.

It is the possibility of using coiled tubing that is of great interest, making it possible for cement circulation. Technology that performs cement jobs using umbilicals without the need of riser is presented in section 4.3.2, but their usage area is quite narrow compared to CT.

4.1.2 Category B vessels

Previously, there was a large gap between category A and C vessels. Category A (RLWI) vessels are the cheaper and more effective choice in doing light intervention work, but their use is limited (see previous section). Category C vessels, typically semi-submersibles, can perform all range of intervention work, but they are extremely expensive and should only be used in value creating operations like drilling. The category B vessel in many ways fills this gap. With the use of a high pressure small bore riser, these are able to perform heavy interventions like coiled tubing, and can also handle live returns. For P&A purposes, this rig can displace cement with the use of coiled tubing, making it possible to set cement plugs in the well (also squeeze cement in annulus). In addition it can be used for some lifting operations. The vessel is still in construction in cooperation between Statoil and Aker Solutions, and the aim is to have it available for use sometime in 2015 [16].

Since the category B vessel is still in construction, its use on the NCS is still unknown. But Helixesg does have a similar vessel they categorize as a category B type vessel, called the Q4000, which has been used to perform 8 different P&A jobs in the GoM. The vessel was constructed all the way back to year 2002, and was refitted for slimbore drilling in 2008. The vessel has a Multi-Purpose Tower (MPT), which has the same role as the derrick has on a conventional semi-submersible, with a lifting capacity of 600 metric tons. In addition it has coiled tubing application, making it very relevant with regards to P&A [17]. The Q4000 is illustrated in figure 28 [17].

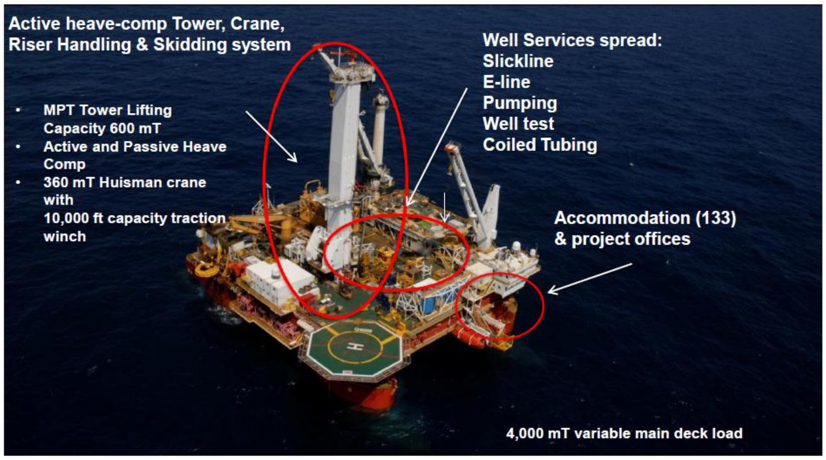


Figure 28: The Q4000 [17]

4.1.3 Category C vessels

Category C vessels are the traditional semi-submersibles/MODUs, and can perform all P&A operations. But they are highly expensive, have limited availability, and should only be used for drilling and workover operations, making them a poor choice for well abandonment. Figure 29 [16] show a typical price range for the different categories, and this shows how significant the cost savings can be if eliminating the use of category C vessels. When these often have a day rate of approximately $500,000 dollars, it is obvious that using the other vessels for P&A operations will save a great deal of money for operators [16].

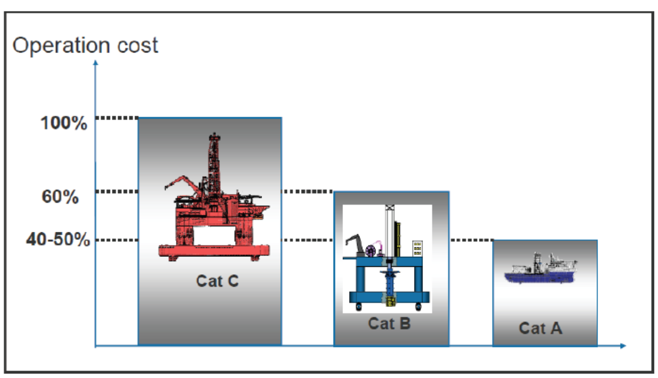


Figure 29: Operation cost for different vessels/rigs [16]

4.2 Reservoir Abandonment, Phase 1

Phase 1 of a P&A operation can be quite complex, and introduce several challenges. It is important to remember that no well barriers are set against the reservoir at this point, so full well control is required. As described in 2.3.4, the main challenges occur when needing to re-establish barriers as a result of poor cement jobs behind casing. This can lead to milling, which is a very undesirable operation. Another challenge is that the installed barriers are required to last for eternity. This means that the material used has to have properties that are able to withstand everything that can happen downhole. In the petroleum industry it is taken for granted that cement is used, resulting in other materials that maybe have more suited properties for P&A being easily neglected. In this section a tool that can replace the need for section milling will be presented, called the *HydraWash* system. In addition two alternative materials to cement will be presented, called Sandaband and Thermaset.

4.2.1 The HydraWash system

In 2008 a company called *HydraWell Intervention* [29] presented a new Perforate, Wash and Cement (PWC) system called the *HydraWash*. This tool was made to eliminate the need for section milling when re-establishing barriers behind casings, and with it resolving all the challenges related to section milling. The HydraWash system can be run as a 3, 2 or 1 trip system, with the 1 trip system completing the whole operation in 1 run. The tool is illustrated in figure 30 [18], consisting from bottom up; TCP perforation guns, two opposing wash cups with circulation ports, and a cement stinger [19].

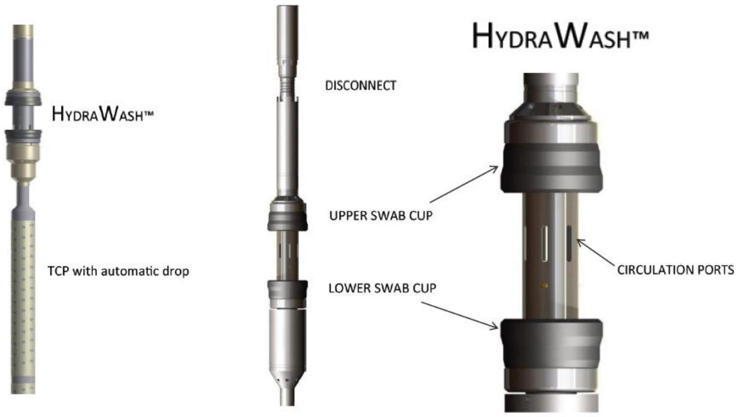


Figure 30: HydraWash tool configuration [18]

To illustrate how this system works, a typical operational sequence will be described for the one trip system. Before the actual PWC operation starts, it can be wise to conduct a logging run to determine where the best suited intervals are situated, as the most desirable sections are the sections with the least cement [19]:

1. When positioning the TCP guns (typically 50 m, with 12 shots per foot) at the desired interval, the shots are first detonated and then dropped to the bottom of the well
    - This is done to make perforations in the casing
2. After the guns are dropped, an activation ball is released which seats in the wash tool sealing of the bottom of the string, and flow is directed through the circulation ports between the two cups. This is first done in the top-down direction, and then repeated in the opposite direction after reaching bottom perforation. The wash cups are designed to isolate and wash only 1 foot of casing continuously, meaning that washing is conducted through 12 perforations at a time.
    - This is done to wash and condition both inside and outside of the casing, all the way to the exposed formation. Old mud, cuttings and settled mud is removed from the annulus, which leads to a more effective cementation
3. The tool is then run to the bottom perforation. Cement spacer is pumped into annulus while pulling the tool upwards.
    - Done to ensure cement bonding to formation and casing

4. A deactivation ball is then dropped and landed to disconnect the wash tool from the cement stinger. The wash tool is pushed to a position below the perforations.
    - The cups have enough contact force against the casing to act as a mechanical foundation for the cement plug
5. A balanced cement plug is set with the cement stinger at the bottom. After pulling above the plug the work string and hole is circulated clean. It can also be chosen to pressure up the well to squeeze the cement into the perforations.
6. The work string can wait downhole until cement is set, before the plug is washed down, tagged and pressure tested. But the normal procedure is to drill out the plug and log the annulus to verify the cement quality. If ok, the P&A operation is completed when a new plug is set inside the casing, tagged and pressure tested.

The typical operational procedure using the HydraWash system is illustrated in figure 31 [18]

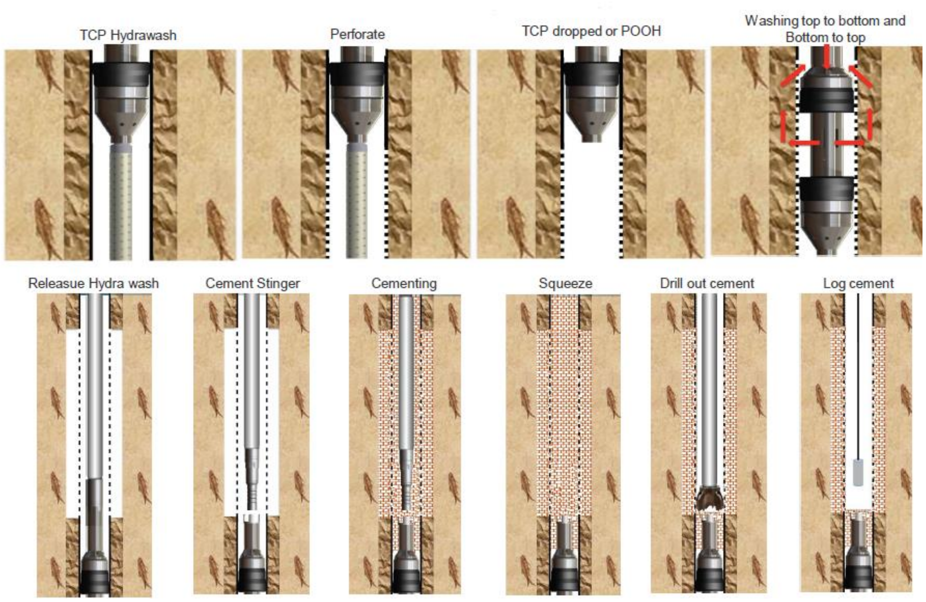


Figure 31: Operational sequence for HydraWash [18]

After the introduction of the HydraWash tool, HydraWell has presented a new tool called the *HydraArchimedes* [29]. This is an integrated part of the HydraWash, and uses its screw design and rotation to squeeze wet cement into the perforations while slowly pulling upwards after the balanced plug is pumped. It was designed to provide an even more effective P&A job using the HydraWash system, and is illustrated in figure 32 [20].

Figure 32: HydraArchimedes tool [20]

As of 2012, the HydraWash system had been used to install 44 cement plugs in casing sizes ranging from 7" to 10 ¾" (36 of the plugs have been installed in 9 5/8" casing). Figure 33 compares time to set 50m well barriers with the HydraWash system, both for 2 trip (perforate and POOH) and 1 trip system, versus a general section milling operation [20]. Operational duration for section milling was based on using 6 wells where 8 conventional section milling operations were conducted. The general operational procedure for section milling was [19]:

1. Section Mill 50 m
2. Clean out
3. Underream the 50 m section
4. Cement

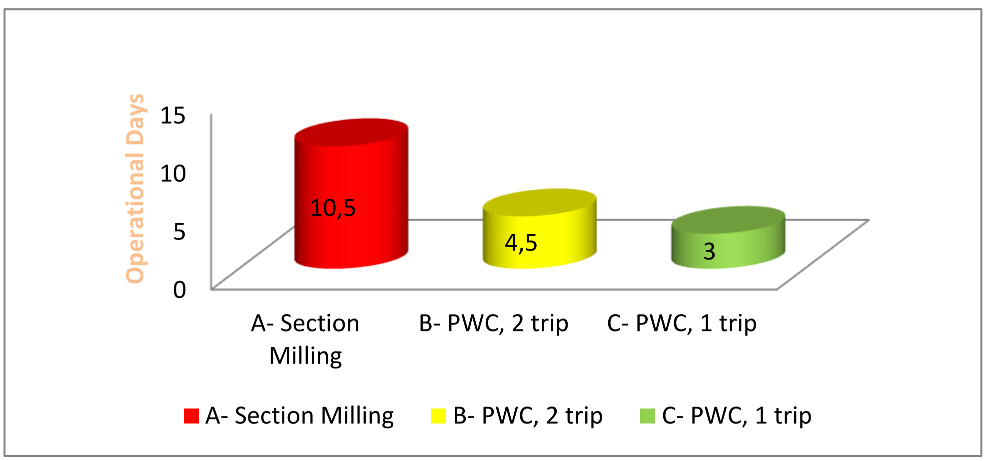


Figure 33: Operational days for HydraWash system vs Section Milling

The results in the figure clearly illustrates days saved using the HydraWash system. The operation goes from an average of 10,5 days for section milling, to approximately 4,5 days for the 2-trip PWC system, and down to 3 days for the 1-trip PWC system. For all the 44 plugs installed, an average of 243 days was saved using this system instead of conventional section milling [20]. In addition to significant time saved, the two other main benefits are:

- 1-trip system
- No swarf. An estimated 176 ton of swarf was avoided for the 44 jobs

The biggest challenge with HydraWash system is fracturing the formation when pumping fluid through perforations. Therefore, perforation sizes and pump rates are carefully engineered to avoid fracturing formation which can lead to losses when washing the perforated intervals, and result in poor hole cleaning. In addition lost mud can return on a later stage and contaminate the cement. Another challenge experienced when first using this equipment was deviated sections, where cuttings and separated mud components settle around the pipe on the low side. This issue was solved using a swivel right above the disconnect section, making it possible to rotate the string so that particles cannot settle around the pipe. The last challenge with the HydraWash system is when the rat hole under the perforated section is not long enough to facilitate the TCP guns. In this case 2 trips are needed, explaining why this system sometimes uses more than one trip to install the cement plugs.

4.2.2 Sandaband and Thermaset, a possible replacement to cement?

In NORSOK D-010, it is required that the well is isolated for eternity after permanent abandonment. As it is the licensee that has responsibility for the well even after abandonment, a leaky well needing re-abandonment will result in massive costs for operators. Alternative material to cement with more suited properties has been developed, but cement is still used in almost all P&A operations as plugging material. Sub-surface geological movement will occur, and cement can easily fracture when shear forces exceeds its strength. That is why it is important to look at alternative materials, and in this section two different materials will be presented, Sandaband and Thermaset.

Sandaband is one material that can be an alternative to cement. It fulfills all the NORSOK requirements, but in addition it possesses important properties cement does not. Sandaband is a sand-slurry system containing a wide distribution of particle sizes. The volume between the large particles is occupied with smaller particles, with the volume between the smaller particles filled with particles down to a micron-sized particles, meaning that the maximum permeability is defined by these micron-sized particles. In addition thorough testing has determined the material as gas tight. The most important property of Sandaband, as a Bingham fluid, is the ability to act as a fluid when shear stresses exceed the yield point, which causes the plug to reshape rather than fracture. Figure 34 [22] illustrates this, showing that Sandaband acts like a solid when shear stresses are below and as a liquid when shear stresses are above the yield point. This is a very favorable property, as the well bore will experience a variety of shear stresses caused by formation subsidence/compaction, earthquakes, vibration, etc. Sandaband has been displaced either by bullheading down tubing, or pumped through a drillpipe (OH in exploration well). After the total volume has been displaced into the wellbore, the verification of the plug can start immediately. Since tagging cannot be applied as this will surpass the slurry's shear strength, verification is performed using mud circulation both above and below theoretical top of slurry while observing returns over the shakers. The biggest challenge with Sandaband is that it needs a foundation; it cannot be set on top of fluid [21]. To summarize, the benefits of using Sandaband are:

- Sandaband is non-shrinking and has the ability to reshape, which gives it the ability to re-heal, eliminating any leakage through channels or microannuli.
- Does not fracture when material strength is surpassed.
- Sandaband consist mainly of quartz sand and water, making it HSE friendly.
- As quartz is a thermodynamic stable mineral, Sandaband remains unaffected by downhole fluids
- Unlike cement, no need to wait for slurry to set, potential to save several hours

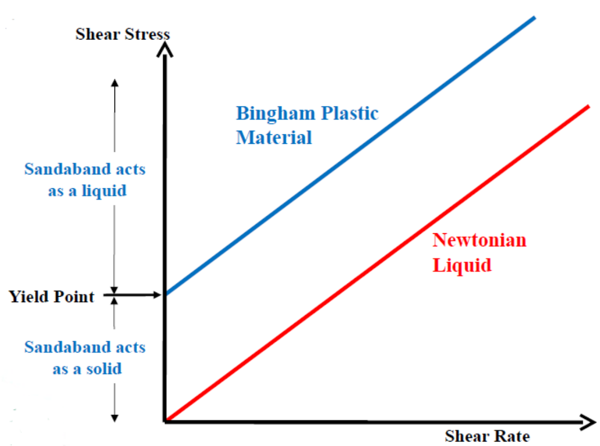


Figure 34: Sandaband as Bingham Plastic [22]

Another material that can be used in P&A operations is ThermaSet. This is a non-reactive polymer that is 100% particle free, and is activated by downhole temperature. ThermaSet can be used in all areas of P&A, and be displaced in the traditional way, or by e.g. coiled tubing. It has been tested and meets all the NORSOK D-010 requirements. Compared to cement, table 11 shows the benefits of using ThermaSet. The table clearly shows that ThermaSet has superior mechanical properties, and in addition tests over a 12 months period concluded that the material is durable [23]. The biggest challenge with ThermaSet is higher price compared to cement.

Properties	Advantages	Thermaset	Cement
Temperature range	Low and high temp	Operating range: 0-150 °C BHT. 320°C when set	
Density range	More flexibility	Min: 0,75 SG, Max: 2,5 SG	
Flexural strength (MPa)	Resist deformation under load	45	10
Tensile strength (MPa)	Resist deformation/Rupture under pulling force	60	1
Compressive strength (MPa)	Resist deformation during axial directed forces	77	58
Rupture Elongation (%)	More elastic. Tolerates thermal expansion. Does not crack	Max 3,5%	Max 0,01%

Table 11: Show the benefits of Thermaset compared to cement

4.3 Intermediate Abandonment- Phase 2

This phase of permanent P&A often consist of pulling upper completion (production tubing above production packer) if not done in phase 1, pulling casing to get access to annulus for intermediate barriers against shallower reservoirs (if present), and in the end setting an open hole to surface barrier (surface barrier). In an ideal world, the production tubing and casing strings would be left downhole, but in most cases these are pulled (described in 2.3.7). There are four main reasons that cause this:

- Pulling production tubing because of poor cement jobs behind casing and presence of control lines.
- Not possible to log through several casing strings

- Intermediate barriers need to be installed in sections where annulus cement is not verified
- Openhole to surface barrier needs to extend across the full cross-sectional area of a well

In this section two different technology solutions will be described. One is a method to pull the production tubing using only wireline, and the other is a tool called the *Suspended Well Abandonment Tool (SWAT)* which eliminates the need to cut and pull casing intervals when installing the surface barrier in subsea wells.

4.3.1 Wireline conveyed pulling of tubing

In a presentation by Aker Well Service AS at a SPE meeting April 2012 [24], a new method of pulling tubing using only wireline (or coiled tubing) was introduced. On platform wells, pulling tubing often needs the derrick to perform this operation, or mobilization of tubing retrieval equipment (Weatherford's Pulling and Jacking unit mentioned in section 5.1) if the platform do not have drilling equipment in place. For subsea wells semi-submersibles are often needed. Figure 35 is based on a presentation by Bård Tinnen (Aker Solutions) at P&A workshop March 2013 [30], and illustrates a typical P&A operational sequence including all three phases. The red sections illustrate operations needing equipment that often consumes time and money, e.g. step 10 and 11. The future goal should be to complete these operations using only wireline or coiled tubing, as illustrated in figure 36. The tool Aker Well Service presented uses only wireline (CT) to pull the production tubing, hence eliminating the need to use a drilling rig or mobilizing other heavy duty equipment. This system uses general wireline equipment, but in addition needs a pipe handling system for when tubing comes to surface [24].

Figure 35: Typical operational sequence for a P&A operation

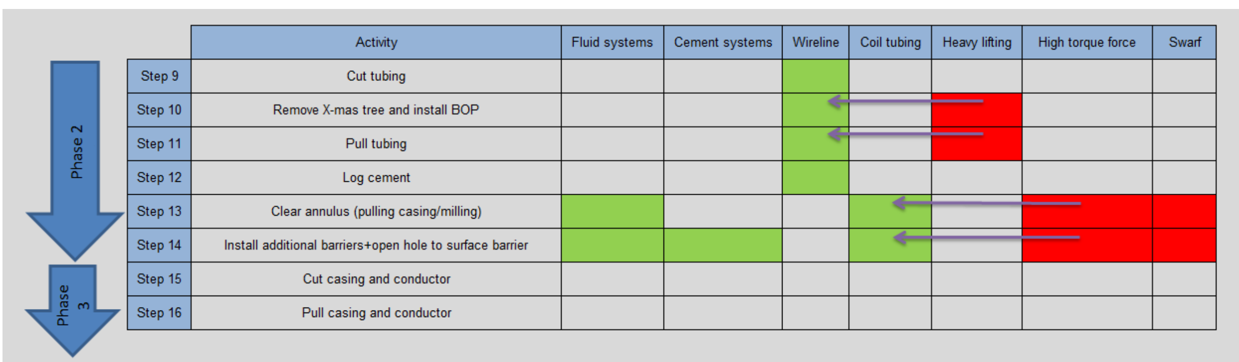


Figure 36: Ideal operational sequence for a P&A operation

The method and tools Aker suggested has an operational sequence as following [24]:

1. The tubing is cut right below the tubing hanger using a tubing hanger cutter tool. Then the tubing hanger is removed by a hanger retrieval tool.
2. A plug with check valve functionality is installed at the bottom of the cut tubing (has to be done for each interval)
3. A tubing pulling tool is engaged at the top of the tubing. This has a control module and a seal and anchor module which seals of the relevant tubing interval

4. Gas is injected through the system and into the tubing section. This displaces the heavier fluid inside to generate additional buoyancy force
5. The tubing is then pulled to surface

The whole essence of this method is the injection of gas to displace the heavier fluid and generate the buoyancy effect, as illustrated in figure 37 [24]. The gas is injected either with a dual line system where gas is injected through a separate line, or single line system that use a hollow wireline for injection of gas (future goal). To illustrate how this method can help pull tubing more efficiently, a 100 meter tubing weighing 2530 kg in air, will at 1500m TVD and filled with N_2, weigh 350kg in a well filled with 1,7 SG brine [24]. This is a significant reduction. But this kind of system needs additional equipment compared to conventional methods. A surface system that can bleed of gas needs to be installed, in addition a pipe engagement system that can handle the pipe when it comes to surface. When it comes to more heavy operations, e.g. solids that have settled around the tubing, coiled tubing can be used instead of wireline for stronger circulation to break the settled solids and circulate this out [24]. As mentioned, this system is just in the development phase, but it shows how wireline/coiled tubing can be used to pull tubing in the future.

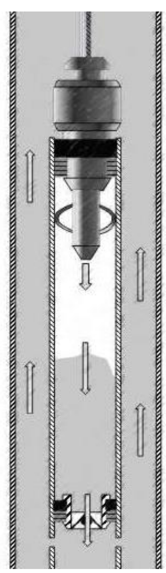


Figure 37: Gas is pumped through a hollow wireline and displaces the heavier fluid [24]

4.3.2 Multi annuli cementing- Suspended Well Abandonment Tool (SWAT)

Phase 2 abandonment is completed when the last open hole section is fully isolated (see section 3.2.1.1). Figure 38 show how the surface barrier needs to be installed inside the 20” casing to fully isolated the well, meaning that 13 3/8’’ and 9 5/8” casing needs to be removed as they are not cemented in this interval. This is a time-consuming operation often needing a drilling rig to complete, and for subsea wells this often means mobilization of a category C vessel that can handle the heavy pulling operations. This is eliminated with a tool called SWAT [25]. The tool is used on category 2 (2.1 & 2.2) temporary abandoned wells (see table 7) to complete phase 2 permanent abandonment, and has since its introduction in 1996 never failed [26]. The tool is deployed from the back of a vessel or through a moonpool, with no riser needed, meaning that RLWIs can be used.

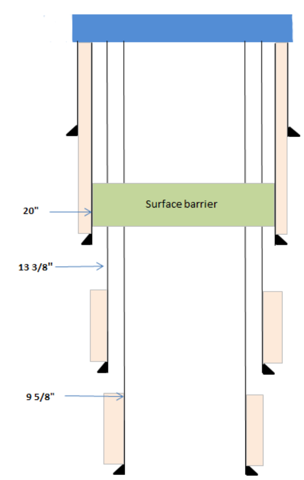


Figure 38: Typical well configuration in area where surface barrier is to be installed

Figure 39 [25] illustrates the tool and all its components. The umbilical system houses two 1,5” circulation lines (one circulation and one return line) and control lines. During operation the SWAT is lowered into the well and landed in the 9 5/8” casing hanger (in this example). The lower and upper packers are then inflated to seal against the casing wall, before a pressure test between the packers are conducted to confirm the integrity of the seals, and is ended with a pressure test below the lower packer to confirm the integrity of the well. The 9 5/8” casing is then perforated by firing the lower 2”gun, with the 9 5/8” x 13 3/8” annulus tested for pressure buildup. The upper 2 7/8” guns are fired next to perforate the 9 5/8” casing and create a circulation path. Mud in the annulus is circulated out by pumping down the circulation line and back through the return line. Spacer and cement is pumped down the return line and through the upper perforations into the 9 5/8” x 13 3/8” annulus, down to the lower perforations. After WOC, the cement in inner annulus is immediately pressure tested to confirm its integrity.

As the inner annulus now is cemented, the outer annulus is ready for cementation. The lower 2 7/8” gun is fired to perforate the 13 3/8” casing, with the annuli tested for pressure buildup. The upper 2” gun is then fired, with the annulus mud circulated out. The lower perforating guns are then released and dropped into the well. A cement plug is then set inside the 9 5/8” casing and the 13 3/8” x 20” annuli, and the operation is completed after the plug is pressure tested and tagged [27]. To summarize, there are many clear advantages using the SWAT to install the surface barrier:

- Eliminates the need to pull casing strings
- Multi-annuli cementation
- Can be performed with a RLWIs, eliminates the need for drilling rigs
- 1 vessel can complete phase 2 abandonment of multiple well campaigns

But the tool does have some limitations, and these are [25]:

- Water depth limit of approximately 90 m (300 ft)
- Working depth limit approximately 180m (600ft)
- Only used for setting surface barrier, have not been used to set e.g. barriers against shallower formations
- Cannot be removed while WOC as the tool itself function as the well control equipment

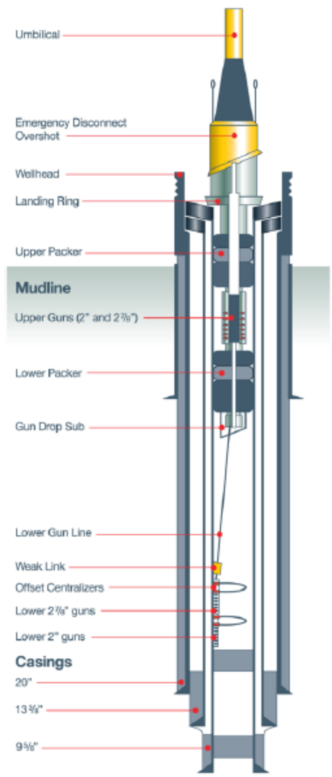


Figure 39: The SWAT [25]

4.4 Wellhead and conductor removal- Phase 3

This phase completes a P&A operation, consisting of removal of the conductor and following casing strings. NORSOK D-010 states that the cutting depth should be 5 meter (~3m in UK) below seabed, and this is followed in most cases. Conventional tools for this operation have been cutting knives or explosives using drilling rigs. With the knives getting worn out easily, one casing size at a time is cut and pulled. The use of explosives gives a more uncontrollable removal, and following HSE issues. In addition, using a rig to do an operation that really is not that complicated is a waste of resources. In recent time new technology has emerged that simplifies this operation significantly; the use of abrasive water jet cutting. There are a couple of companies that use this technology to remove wellheads, with the basics being the same.

4.4.1 Abrasive water cutting system

Figure 40 [28] show Claxton Engineering's abrasive water jet system called SABRE, with the principle being the same for all companies; water is mixed with abrasive particles, and under high pressure the slurry is pumped through a nozzle, creating high kinetic energy. The high velocity slurry can be used to cut through several layers of casing, from the inner casing all the way out to the conductor, including layers of cement. The abrasive material used in SABRE is garnet which is a semi-precious stone. The slurry goes through an umbilical system, and the nozzles are situated in a manipulator that rotates to cut casing 360 degrees. The SABRE system can be deployed from platforms as a modular setup, and from RLWIs for subsea wells. Prior to cutting a subsea well, slings from a crane or winch is attached to the wellhead using a ROV. This is done to be able to pull the wellhead up to deck after the cut is completed [28]. Currently the SABRE system has a water depth limit down to 125m, which can be an issue on some subsea wells [33].

Another company that uses abrasive water jet system to remove subsea wellheads is NCA [5], called The Subsea Wellhead Picker. This has already been used on the NCS, e.g. on the Trolla field where it successfully removed the wellhead on an exploration well. The main difference between this and the SABRE is that the Subsea Wellhead Picker uses a combined tool for cutting and removing wellheads. In addition in can work on water depths down to 500m, hence applicable for most subsea wells on the NCS [34].

There are several benefits of using abrasive water cutting systems, some being:

- For subsea wells, RLWIs can be used
- For platform wells SABRE is a modular system, no need for rig
- Can cut through multiple strings, and recover simultaneous. Subsea P&A uses combined tool for cut and recovery
- HSE friendly
- Both tools have a proven track records over multiple campaigns
- Works regardless of casing load and eccentricity

SABRE™ has been designed to offer a flexible and modular solution.

1: Mix Fill system

2: Water Header / Supply Tank

3: High Pressure Water Pump

4: Work Shop Container

5: Air Compressor (multi string cutting)

6: Umbilical Reel

7: Goose Neck

8: Down Hole Manipulator

9: Sub-Sea or Platform Well

Figure 40: The SABRE abrasive water jet system [28]

5. P&A technology in use- proposed improvements

In chapter 4 different technology solutions and methods with regards to P&A were presented, and further discussed in chapter 6. To give a better overview over how and when to use these different example cases will be discussed. This will be done for both platform and subsea wells, with emphasis on vessel choice for subsea wells.

5.1 Platform abandonment

As mentioned previously, the main challenge with regards to platform P&A is how to perform operations offline, meaning not utilizing the drilling rig. While for situations where the drilling rig is needed, the goal should be how to use it efficiently. For Statoil, almost all platforms have the drilling rig in place, so examples using platforms without drilling rigs will not be mentioned. The examples to be used are from Statfjord A, being the first of three platforms to be abandoned in the Statfjord field. The Statfjord A platform consist of a North and South side, where the drilling rig performs operations on one side, while other operations like wireline are performed on the other side. The drilling rig can be skidded from side to side depending on which side a relevant well is positioned (in total 40 wells and two unused conductor [6]). Figure 41 [6] (same as figure 7) show a typical P&A configuration for a Statfjord A well, where two barriers are needed against the main reservoirs (Brent and Statfjord), and against the shallower formations in the Rogaland group. In this section a best and a worst case scenario will be described, with suggestions on what technology solutions presented in this thesis can improve the different phases. Technology solutions not described will also be used, being coiled tubing and Weatherford’s Pulling and Jacking unit. The well configuration is a cased hole completion, but the principles apply for other completions as well. It is important to note that this is just example cases to show how new technology and methods can improve P&A operations. The Wireline conveyed pulling of tubing method described in 4.3.1 will not be used in the examples as the technology is still at an early stage.

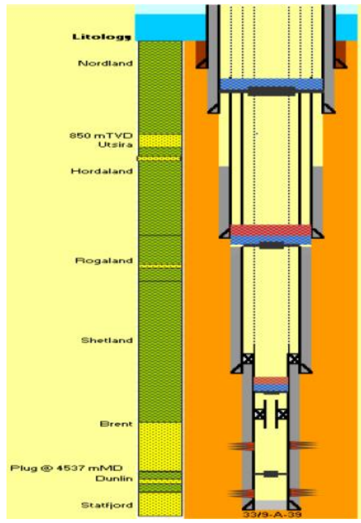


Figure 41: P&A configuration for Statfjord A well [6]

5.1.1 Best case scenario

A best case scenario can typically have an operational sequence as following (some operations can be excluded):

Reservoir Abandonment, phase 1

1. The barriers against the reservoirs are bullheaded into 7” liner
   - External cement for 7” liner documented as good quality
   - WL install mechanical foundation prior to cement displacement
   - If bullheading not possible, use cement stinger to displace cement
2. XT removed, BOP installed, tubing cut above production packer and pulled using rig (can be done prior to installing barriers if not bullheading)

Intermediate Abandonment, phase 2

3. The barriers against Lista formation (Rogaland group) installed by cement stinger
   - 9 5/8” casing cut and pulled without complications
   - External cement for 13 3/8” casing documented as good quality
4. Surface barrier installed in 20” casing by rig
   - 13 3/8” casing cut and pulled without complications
   - External cement for 20” casing documented as good quality

Wellhead and conductor removal, phase 3

5. The 20” casing and conductor removed using rig
    - Cut and remove both 20” casing and conductor

As seen from the operational sequence above, most operations are completed using the drilling rig. Each phase will be discussed to suggest how operations can be enhanced by using alternative technology. As the goal is offline P&A for platform wells, it is important to note that there are systems that can pull tubing and casing rigless which has not been presented in this thesis. One of these is Weatherford’s Pulling and Jacking unit. This has the ability to pull up to 99,790 kg in 60ft (18,3m) increments, and jack up to 272,155 kg in 6ft (1,83m) increments [31]. This will not be described in more detail, but will be used in the examples for platform abandonment as a way of improving operations.

Table 12 and the following explanations gives an overview over the traditional methods already described, and compares them with alternative methods introduced in this thesis to show how these can improve operations.

P&A operation	Traditional method	Alternative method	Cause of using alternative method	Rig/offline
Reservoir abandonment (Phase 1)				
WL operations (logging, setting mechanical foundation, etc.)	Use of WL	N/A	N/A	Offline
Bullhead cement to install barriers	Use of cement	Sandaband/ThermaSet	Superior properties compared to cement	Offline
If not able to bullhead cement, use other method	Use of cement stinger (w/rig)	Use of CT	Offline work, rig is not used	Offline
Pull tubing (can be done prior to installing barriers)	W/rig	Pulling and Jacking unit	No need for rig	Offline
Intermediate abandonment (Phase 2)				
Barriers against Lista fm.	Cut and pull 9 5/8" casing to facilitate barriers (w/rig)	HydraWash (perforate and cement)	No need to pull tubing	Rig (as for now)
Pull casing strings to facilitate surface barrier	W/rig	Pulling and Jacking unit	No need for rig	Offline
Surface barrier	Use of cement stinger (w/rig)	Use CT to set foundation and displace cement	No need for rig	Offline
Wellhead and conductor removal (Phase 3)	Use of rig to cut and pull	Abrasive water cutting system	Cut and pull wellhead	Offline

Table 12: Comparison between initial and alternative methods for best case scenario

Reservoir abandonment (Phase 1)

- Use Sandaband/ThermaSet as they have more suited properties than cement (see section 4.2.2)
- If not able to bullhead cement, coiled tubing should be used to install cement barriers (assume use of cement) as it eliminates the use of drilling rig
- The pulling and jacking unit is used to perform tubing retrieval offline, eliminating the need to use the drilling rig

Intermediate abandonment (Phase 2)

- Use HydraWash to set barriers against Lista formation. The need to pull casing is eliminated and time is saved. For now a rig is needed when using HydraWash, but if made possible to use coiled tubing in the future this can be done rigless (discussed more in chapter 6). As seen from figure 41 the operation is done in an uncemented interval, so it has to be decided if washing operations are needed. If not just perforate and cement. This can be done if verified cement on outside of 13 3/8” casing from original cement job. If not 9 5/8” needs to be removed as it is not possible to log through multiple casings.
- To facilitate the surface barrier two casing strings need to be cut and pulled. This is done using the pulling and jacking unit, with it performing this operation offline. Coiled tubing is then used to install a mechanical foundation and later displace cement.

Wellhead and conductor removal (Phase 3)

- Abrasive water jet system is used to cut the conductor and all the following casing strings in one run, and pulled by different methods described in section 4.4.1. The whole operation is performed offline.

This shows how using alternative methods can eliminate or limit the use of rig. A very interesting thing to note is that if HydraWash could be used with coiled tubing, the whole operation can in theory be performed offline. But using different tools need extra mobilization, so this has to be considered in each case. But this example shows how using alternative technology can contribute in reaching the goal of performing operations offline.

5.1.2 Worst case scenario

As for the previous example;

Reservoir Abandonment, phase 1

1. XT removed, BOP installed, tubing cut above production packer and pulled using rig
2. Rig used to install reservoir barriers due to failed external cement outside 7” liner
   - Mill 100m of 7” liner to facilitate barriers
   - Rig installs barriers

Intermediate Abandonment, phase 2

3. The barriers against Lista formation (Rogaland group) installed using rig
   - Difficult to pull 9 5/8” casing
   - Failed external cement outside 13 3/8” casing
   - Mill 100 m of 13 3/8” casing
   - Rig installs barriers
4. Surface barrier installed in 20” casing using rig
   - Difficult to pull 13 3/8 casing
   - Rig installs barriers

Wellhead and conductor removal, phase 3

5. The 20” casing and conductor removed using rig
   - Cut and remove both 20” casing and conductor

In this scenario many things have gone wrong, and milling is needed to establish failed WBEs. As mentioned many times in this thesis; milling is something that should be avoided. In this scenario the rig needs to perform most operations; the question is how to use it most efficiently. Table 13 and the following explanations illustrate what can be done to improve operations.

P&A operation	Initial method	Alternative method	Cause of using alternative method	Rig/offline
Reservoir abandonment (Phase 1)				
WL operations (logging, setting mechanical foundation, etc.)	Use of WL	N/A	N/A	Offline
Pull tubing	W/rig	Pulling and Jacking unit	No need for rig	Offline
Mill 100m of 7" liner and set reservoir barriers	W/rig and milling equipement	HydraWash	No need to mill (no Swarf)	Rig (as for now)
Intermediate abandonment (Phase 2)				
Pull 9 5/8" casing	W/rig	Pulling and Jacking unit	No need to mill	Offline
Mill 100m of 13 3/8" csg for barriers against Lista fm.	Use of rig to mill 100m 13 3/8 csg to facilitate barriers	HydraWash	No need to mill (no Swarf)	Rig (as for now)
Pull 13 3/8" casing to facilitate surface barrier	W/rig	Pulling and Jacking unit	No need for rig	Offline
Surface barrier	Use of cement stinger (w/rig)	Use CT to set foundation and displace cement	No need for rig	Offline
Wellhead and conductor removal (Phase 3)	Use of rig to cut and pull	Abrasive water cutting system	Cut and pull wellhead	Offline

Table 13: Comparison between initial and alternative methods for worst case scenario

Reservoir abandonment (Phase 1)

- The tubing is pulled using the Pulling and Jacking unit, performed offline.
- Here the challenge is milling a 100 m section to facilitate the reservoir barriers because of failed external cement outside 7”. Using the HydraWash system eliminates the need to mill, and perforates, wash and cement 50 meter sections (one barrier) in one run. This will save a lot of time and no swarf will be generated (see section 4.2.1).

Intermediate abandonment (Phase 2)

- As for phase 1, failed external cement outside 13 3/8” casing results in milling 100 m of 13 3/8” casing. The HydraWash system is again used to install the two barriers, resulting in no milling.
- Assuming 9 5/8” casing was removed in previous operation, Pulling and Jacking unit is used to pull 13 3/8” casing to facilitate surface barrier, and with it eliminating the need to use the rig. Coiled tubing is then used to install mechanical foundation and displace cement in 20” casing to release the drilling rig.

Wellhead and conductor removal (Phase 3)

- Abrasive water jet system is used to cut the conductor and following casing strings in one run, and pulled as for the previous example.

Here the use of HydraWash instead of section milling will significantly improve the operation. Not only will it save a considerable amount of time, but all the generated swarf will be eliminated. Again, making it possible to use HydraWash with coiled tubing in the future would result in the ability to perform this highly complex scenario offline. That is an extreme improvement for a P&A operation including two phases with digit 4 complexity (section 3.3.6). As for the previous example, it is important to note that mobilization of different tools are needed, and has to be considered in each case. But again, this example shows how alternative technology can improve operations and reaching the goal of offline operations.

5.2 Subsea Abandonment

Compared with the UKCS and the GoM, experience with subsea abandonment on the NCS is severely lacking. But in the future subsea abandonment will be a major contributor in P&A here on the NCS. In that regard, a high potential exist in moving operations from semi-submersibles to LWIs. In this section different example cases will be described, showing how LWIs can be used for full or partial subsea P&A.

The examples used are for batch operations, meaning that several wells are to be permanent abandoned consecutively, being 5 wells in these examples (e.g. in a subsea template). Further assumptions will be:

- The assumed P&A configuration (figure 42) is quite simple. This is done to clearly show how technology can improve operations. Many wells do have a more complex configuration.
    - 1 reservoir. The primary and secondary plug (one long plug of 100m) are put on top of WL installed mechanical foundation inside 7" liner
    - The yellow line represents the production tubing, this is pulled before setting the surface barrier
    - Assume category 2.2 wells (see table 7, two annuli uncemented with regards to surface barrier)
    - Mobilization and preparation work are included in the different phases

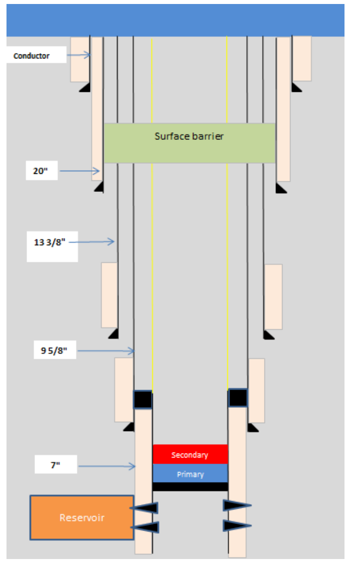


Figure 42: Well configuration, subsea well

5.2.1 Semi-submersible completed P&A

When the five wells are to be permanent abandoned, the conventional method is using semi-submersibles (category C vessel) to complete all phases. Table 14 describes how a semi-sub is used to permanently abandon the 5 wells in question. It goes through all the 3 phases, including mobilization and transit.

Case 1- Semi-submersible completed abandonment				
P&A phase	Sequence	Activity	Vessel	Comments
Phase 1- reservoir abandonment	1	Preperation and mobilization	Semi-Sub	
	2	Transit to location	Semi-Sub	
	3	Position semi-sub and prepare operation	Semi-Sub	Typically killing the well, survey, N/D XT, N/U BOP, install mechanical foundation etc.
	4	Pull production tubing	Semi-Sub	Can be done in phase 2
	5	Install reservoir barriers	Semi-Sub	
Phase 2-intermediate abandonment	6	Remove casing strings to facilitate surface barrier	Semi-Sub	9 5/8'' and 13 3/8''
	7	Install surface barrier	Semi-Sub	
Phase 3-Well head removal	8	Cut conductor and 20'' casing	Semi-Sub	Use either knives, explosives or SABRE modular system
	9	Wellhead removal	Semi-Sub	
	10	Post P&A work	Semi-Sub	
P&A work completed	11	Deanchor and transit to shore	Semi-Sub	Done after all wells are abandoned
	12	Demobilization	Semi-Sub	

Table 14: Semi-Submersible completed P&A

In this thesis there has several times been stated that the use of semi-submersibles should be avoided for subsea abandonment, and that the future goal should be moving all P&A operations away from these and to category A vessels. But it is important to remember that typical category C vessels have many superior properties compared to LWIs, and with current technology it is impossible to use lighter vessels for some operations (typically operations with complexity code 3 and 4). Some main advantages with using semi-submersibles are:

- Can perform all P&A operations
- Superior alternative if needing cement remedial (Performing milling operations or HydraWash system)
- Can pull tubing and casing if needed
- Much more suited if experiencing unexpected events during operations
- Compared to lighter vessels, a much more robust alternative with regards to weather conditions
- No extra mobilization of other vessels needed as for other examples (5.2.2 and 5.2.3)

To conclude it can be said that using semi-subs for P&A operations is a safer option, it will be much more able to handle unexpected events during operations, and has a superior range of usage. And as the situation is now, the need for semi-subs to perform the most complex operations will probably always be present.

5.2.2 The LWI and Semi-Sub completed P&A

With regards to technology and striving for economical sustainability, a possible method of performing subsea P&A jobs currently is using a combination of LWIs and semi-submersibles. Table 15 shows how this kind of operation could be performed. The LWIs in this example are category A vessels as defined in section 4.1.1, and operate without a riser, and therefor defined as RLWI in the table (Riserless light well intervention vessels). It is important to note that Statoil has already used RLWIs in P&A jobs. This was done on 5 wells at Troll Oseberg Gas Injection (TOGI), where a RLWI was used to secure the wells by killing, punching tubing and installing temporary plugs for all 5 wells. In addition the RLWI removed all X-mas trees, before a semi-submersible completed the permanent P&A job [32]. This shows that Statoil already have used RLWIs for P&A on the NCS.

Case 2- RLWI and Semi-submersible completed abandonment				
P&A phase	Sequence	Activity	Vessel	Comments
Phase 1- reservoir abandonment	1	Preparation and mobilization	Semi-Sub	
	2	Transit to location	Semi-Sub	
	3	Position semi-sub and prepare operation	Semi-Sub	Typically killing the well, survey, N/D XT, N/U BOP, install mechanical foundation etc.
	5	Pull production tubing	Semi-Sub	
	6	Install reservoir barriers	Semi-Sub	
	7	Perform post P&A work	Semi-Sub	E.g. Installing corrosion cap, N/D BOP
	8	Deanchor and transit to shore	Semi-Sub	After all 5 wells have installed barriers
	9	Demobilization	Semi-Sub	
Phase 2-intermediate abandonment	10	Mobilize vessel for phase 2 abandonment	RLWI	
	11	Transit to location	RLWI	
	12	Position vessel and prepare for operation	RLWI	E.g. Removal of corrosion cap, install required equipment
	13	Install surface barrier through multiple annuli	RLWI	Using the SWAT
Phase 3-Well head removal	14	Position vessel and prepare for operation	RLWI	
	15	Cut and remove conductor and wellhead	RLWI	Using Abrasive water cutting system
P&A work completed	16	Transit to shore	RLWI	Done after all wells are abandoned
	17	Demobilization	RLWI	

Table 15: RLWI and Semi-submersible completed P&A

Based on current technology, partial P&A is the most realistic way to abandon wells by including RLWIs. In this scenario the semi-sub is used for phase 1 abandonment, including pulling tubing, as this is the most difficult phase to complete. As mentioned previously, RLWIs has been used to perform some typical pre-work for phase 1 abandonment, as Statoil did on TOGI. If phase 1 includes cement remedial, a semi-sub has to be used for this as well (e.g. milling or HydraWash). After the well has two barriers against the reservoir, the RLWI can perform the two last phases. If there were shallower formations needing barriers like in section 5.1, this could result in removal of casing strings to facilitate these. The semi-sub could then have completed these operations before the RLWI completed the rest. Some of the main advantages with using RLWIs in partial P&A are (this scenario):

- Semi-sub completes the more complex phase 1 abandonment
- If cement remedial is needed for the reservoir section, semi-sub can do this
- Releases the semi-sub earlier to conduct other well operations
- The significantly cheaper RLWI completes two P&A phases
- The SWAT tool used from RLWI eliminates the need to pull casing strings
- Abrasive water cutting system removes the wellhead and following casing strings simultaneously from a RLWI

As this is one of the more interesting solutions with regards subsea abandonment, it is important to note some of the challenges:

- Limited usage area, not as adaptable to unexpected events
- Inferior alternative to semi-sub with regards to weather

5.2.3 The LWI completed P&A

The goal for the future with regards to P&A is removing the use of semi-subs more or less altogether; this should especially be possible on wells with lower complexity (like in figure 42). This will result in a significant cost reduction for operators, and will release semi-subs to perform drilling operations. But for this to be possible, there are several technological gaps that need to be filled (see section 2.3.2), most notably pulling tubing or casing, and displacing cement without the use of riser. LWIs that are able to use riser systems were briefly presented in 4.1.1 (Category A+ and A++), so they do exist. But they are less robust with regards to compensating high motions, and working on live wells present technical challenges because of the interface between high pressure hydrocarbons and the low pressures on the vessel (less robust pressure control equipment compared to semi-subs). In this example the assumption is that a LWI w/riser exists with the ability to circulate cement through CT, and pull tubing for phase 1 abandonment. Because of limited deck space it is assumed that the vessel demobilizes after phase 1, before completing phase 2 and 3.

Case 3- LWI and RLWI completed abandonment				
P&A phase	Sequence	Activity	Vessel	Comments
Phase 1- reservoir abandonment	1	Prepare and mobilize LWI	LWI	W/riser
	2	Transit to location	LWI	
	3	Position vessel and prepare for operation	LWI	E.g. kill well, N/D XT, N/U BOP, connect riser, removal of plugs, survey, mech .foundation, etc.
	5	Install reservoir barriers	LWI	With coiled tubing
	6	Remove production tubing	LWI	With equipment able to pull tubing from LWI
	8	Disconnect and transit to shore	LWI	After all 5 wells have installed barriers
	9	Demoblization	LWI	
Phase 2-intermediate abandonment	10	Mobilize RLWI	RLWI	Riser not needed
	11	Transit to location	RLWI	
	12	Position vessel and prepare for operation	RLWI	
	13	Install surface barrier through multiple annuli	RLWI	Use the SWAT
Phase 3-Well head removal	14	Prepare for phase 3 abandonment	RLWI	
	15	Cut and remove conductor and wellhead	RLWI	Use Abrasive water cutting system
P&A work completed	16	Transit to shore	RLWI	Done after all wells are abandoned
	17	Demobilization	RLWI	

Table 16: LWI completed P&A

In this example a LWI and RLWI is used to complete a full P&A operation. As deck space is limited compared to semi-subs, the vessel needs to demobilize after completing phase 1. The benefits of using LWIs for full abandonment of subsea wells have been discussed previously, most notably being a lot cheaper and released rig time for drilling, but there are several challenges that need to be solved:

- Either making it easier to use LWI w/riser, or being able to displace cement and pull tubing/casing without riser and still have full well control
- Integrating CT with LWIs. Using CT without riser would be a significant improvement for RLWIs
- Technology advances making it possible for LWIs to perform more complex operations:
    - E.g. how to re-establish WBEs from LWIs?

There are many challenges that need to be addressed before using LWI for full subsea abandonment, but the gains are so significant that there should be a collective industry push making this possible in the future.

6. Discussion

In this section the issues previously described in this thesis will be discussed, building up to conclusions in the next chapter.

6.1 Regulations and guidelines

A thorough analysis of the regulations and guidelines used on the NCS and UKCS has been conducted. One of the main goals of the thesis is to come with suggestions for improvements and changes in NORSOK D-010, mainly by analyzing the *Guidelines for the suspension and abandonment of wells* (will be referred to using the abbreviation *UKG* going forward) and two other UK guidelines for assistance. Similarities will be mentioned to some degree, but the emphasis will be mainly on differences.

6.1.1 Differences in document structure

One of the biggest differences between NORSOK D-010 and the UKG is the way they have been structured. The UKG is a far more elaborating document than NORSOK D-010, something that is expected as it is far more comprehensive and released in 2012. The question is what is more beneficial for operators?

The UKG is made to steer operators to comply with the legislative requirements in *The Offshore Installation and Wells (Design and Construction, etc) Regulations*. Like for NORSOK D-010, it states that the guideline provide minimum criteria to ensure full and adequate isolation of formation fluids, but it's intend is to provide the framework for the decision-making process for P&A operations. Further it encourages operators to make their own standards and procedures, as long as they comply with the legislative requirements, meaning that the UKG is mainly made to help and advice. In NORSOK D-010, the use of the term *shall* is for requirements, and it states that when used it should be followed strictly. But the *shall* term is not actual legislative requirements that operators are to follow by law, but are referred to as a way of fulfilling the functional requirements in the regulations issued by PSA. Despite this, NORSOK D-010 feels like a prescriptive document that is strictly to be followed when using this term, while the UK guideline is more advisory. Making the P&A section of NORSOK D-010 more comprehensive and elaborating, but purely advisory, with the goal of fulfilling the legislative requirements could be a way to structure a future version of NORSOK D-010. It should also be considered to make a standard purely for P&A, as in UK.

6.1.2 Barriers

When it comes to permanent barriers, many of the requirements are the same for NORSOK D-010 and the UKG, some are:

- All permeable zones should be abandoned with at least one permanent well barrier
- Two permanent well barriers if the zone is a reservoir (this is defined differently for both cases, will be mentioned later)
- The permanent well barriers needs to extend across the full cross-sectional area of a well
- Should be installed as close as possible to the source of inflow
- The formation integrity should withstand the potential internal pressure at the base of the well barriers (both primary and secondary)

In NORSOK D-010, one well barrier is required between any *potential source of inflow* and the surface, with this "source of inflow" being defined as a formation with permeability. Further, if a permeable formation contains hydrocarbons, it is defined as a reservoir. In UKG, a permeable zone is considered hydrocarbon-bearing if *moveable* hydrocarbons are present. Here a difference in terminology is observed. It is hard to determine what NORSOK D-010 means with *potential source of inflow*, and with regards to hydrocarbons present, is there a limit with respect to hydrocarbon permeability? There should be a clear definition of these terms in NORSOK D-010, as they are very important with regards to barrier design. An example is if a formation has traces of hydrocarbons, but significant flow is highly unlikely, is then two barriers needed? And are well barriers always required when a formation has permeability?

Another issue with terminology in NORSOK D-010 is when a permeable formation is regarded as a reservoir when it has "flow potential", with flow potential not defined. In UKG this flow potential is defined as a formation being water-bearing and overpressured, more or less as defined in Statoil (permeable and over-pressured). NORSOK D-010 should define this "flow potential" term as in the UKG. It should also be considered for both documents if two barriers are needed against formations that do not contain hydrocarbons even if they are overpressured.

When it comes to height requirements, NORSOK D-010 and UKG are principally the same, with the differences explained in chapter 3. An important thing to note is that it seems like height requirements are purely empirical numbers, and they vary from country to country. There should be more scientific work done on this subject, as the most important thing is that a plug can survive downhole and seal, not its height. In principal, as long as a plug can withstand the anticipated differential pressures for a longer period of time while keeping isolation, the height does not really matter.

One last thing that should be discussed on this subject is the use of "eternity" in NORSOK D-010. It is required that a permanently plugged well is abandoned with an "eternal" perspective. This word is totally absent in the UKG, where the well barriers are to obtain "isolation" from relevant zones. It is clear that the use of eternity is very confusing, as it really has no meaning. It is impossible for a barrier to last forever, as nature will after some time destroy the barrier and probably isolate on its own. And with regards to simulations conducted around barrier design, it is clear that using "eternity" as an input in models is impossible. A claim can be that the use of "isolation" is not sufficient, but in comparison to the use of eternity, it is clearly more favorable.

6.1.3 Verifying casing cement

Verifying the cement quality on the outside of casing is required as permanent well barriers must extend across the full cross sectional area of wells. When it comes to verifying TOC, both NORSOK D-010 and UKG recommend the use of logs or recorded parameters from the cement placement, with UKG recommending a longer cement column to allow for uncertainty if the latter method is used.

For the verification of cement quality in annulus, NORSOK D-010 is quite unclear. If information about the cement job from the original well construction like logs, job parameters and formation integrity tests do not exist or are non-conclusive, NORSOK D-010 does not provide clear guidance on how this should be done, making it easy to resort to logging. On this issue, UKG is much clearer. It states that the sealing quality of the casing cement should be assessed with the different parameters described in 3.3.2.2. In addition UKG provides a set of tables that are aimed to help clarify the verification requirements (see appendix A). NORSOK D-010 should be more elaborated on this issue, as in the UKG

Another issue is the use of tested annulus as a way to verify the cement quality. This is mentioned in some degree in UGK, where *absence of sustained casing pressure during life cycle of well* is something that should be assessed with regards to the sealing capability of the cement. The point is that if annulus is tested, and no pressure buildup is observed, this can be evidence that the cement is sealing and an acceptable WBE. This is especially applicable for older wells where the cement already has been sealing for decades, and in relation to the "eternity" term in NORSOK D-010, there is nothing suggesting that it will not continue to seal. Another method would be to pressure test the annulus cement through perforations to see if a barrier seals, as included in UKG. As mentioned in 2.3.8, there are a lot of uncertainties when it comes to verifying the cement quality with logs, so why is not actual tested annulus better than just logged annulus? This is something that should be looked at for NORSOK D-010, with the goal finding ways of using tested annulus (or other methods) in situations where logging is not beneficial or inconclusive.

A way to accept barriers with regards to logging, or the lack of it, can be to vary the height requirements. The casing cement can be verified by other methods than logging, like tested annulus and parameters from the cement displacement job. An example on how annulus cement for one barrier can be accepted is:

- 15m logged continuous cement
- 25m logged un-continuous cement (cumulative)

- 50 m unlogged cement, verified by other methods

It is important to note that operators should be given a lot of responsibility themselves to find ways of verifying barriers, this was just an example to show how this can be done. They know the ramifications of having leaking barriers after abandonment, and will do their utmost to have them seal as required.

6.1.4 Using formation as a part of well barriers

As described in 2.3.9, certain formations like shale can move onto casing where cement is missing (shale bonding), and if sufficient amount of formation packs onto the casing this can be used as a part of well barriers as a substitute for cement. In NORSOK D-010 this is not mentioned, just that a separate WBEAC is required if different materials than cement is to be used, something Statoil has done for shale bonding. Oil & Gas UK has identified this and made it a part of the UKG. As described in 3.3.3.9, guidelines to qualify the formation as a part of barriers are included, with many similarities to the Statoil requirements. Guidelines around this topic should be included in the next revision of NORSOK D-010. It is important that these describe what should be the basis for qualifying formation as a part of a permanent barrier. In UKG one of the requirements is that the formation is both logged and leak tested. The same apply for Statoil, but here shale formation that is proven geologically homogenous and laterally continuous does not need to be leak tested if previously done. There should be clear recommendations to when both logging and physical testing is needed, and when logging alone is sufficient.

6.1.5 Qualification of new isolation materials

In NORSOK D-010, the use of other materials than cement for permanent well barriers are not mentioned in great detail, only that a separate WBEAC is required and that the material used must withstand the load/environmental conditions it can be exposed to. In addition NORSOK D-010 states that testing should be performed to establish the long term integrity of the material. In UKG, cement is as in NORSOK D-010 considered the prime material for P&A, but Oil & Gas UK has in addition made a separate guideline called called the *Guidelines on qualification of materials for the suspension and abandonment of wells* as mentioned in section 3.3.5. Despite acknowledging cement's operational limitations and other materials developed, there has not been many advances in using/testing alternative materials in wells. This guideline states that one significant reason is that permanent P&A is done with an eternal perspective and uncertainty about the long-term integrity of alternative materials is a hindrance for their use. Further it is stated that the aim of the guideline is to encourage use of other isolation materials in P&A operations. The same type of document should be made for the NCS. It would be easier for operators to use alternative materials if a standardized process on how to qualify these existed, and the guideline used in UK would serve as a good basis in constructing such a document.

6.1.6 Removing equipment above seabed

In NORSOK D-010 the requirement is that no parts of the well will ever protrude the seabed after abandonment, and that the cutting depth should be 5m below seabed. There is no point in having a recommended cutting depth in NORSOK D-010 (or UKG). Operators should themselves decide what is sufficient. A cutting depth of 2 meters or 5 meters does not really matter, as long as the well does not protrude the seabed or affect activities like fishing. Another issue is when abandoning platforms and large structures are to permanently remain at the seabed around the wells. In UKG this is included, saying that no casing strings should extend above any remaining structures. This is more reasonable than what is required in NORSOK, where the cutting requirement applies for all type of wells.

6.1.7 Concerning future reservoir pressure

The future reservoir pressure determines the shallowest depth a well barrier can be installed, as described in section 3.2.1.2. There should be a study on if there is any point of using virgin pressures for barrier design. Being able to use lower pressures makes it possible to install barriers at shallower depths, simplifying operations. If the reservoir pressure ever returns to its initial state, the probability is quite high that nature then isolates on its own.

6.1.8 Importance of initial well design

A sound initial well design can in theory eliminate all technical P&A challenges. Especially when it comes to cement jobs when drilling wells is this important, as poor cement jobs can have been accepted with no regards to future abandonment. This is a major problem, as re-establishing WBEs is an operation that is complex, takes time, and can cause HSE issues (swarf).

This can be avoided if a well is designed with abandonment in mind. In NORSOK D-010 initial well design and P&A is not mentioned at all. This is not the case for the UKG, as it is stated in the foreword that "*It is recognized that the key to a simple temporary or permanent abandonment often lies with the soundness of the initial well design and effectiveness of the primary casing cementations. The benefits of successful cementation should lead to an easier suspension or abandonment."* [11]. This is once again mentioned in the UKG as a special consideration for P&A (see section 3.3.3.1). In addition, it is a legislative requirement in UK that wells are designed and constructed so that it can abandoned in a "safe manner" (see introduction to section 3.3, regulation 15). This is something PSA and Norway really should look into, and the importance of sound initial well design with regards to P&A should be highlighted in NORSOK D-010. This can increase the awareness when it comes to this issue, and make operators design wells to ensure effective and safe future abandonment. In some cases this can lead to higher cost when designing and constructing wells, but this will probably be a small number compared to the money saved on future abandonment.

6.1.9 Temporary abandonment

As the situation is now, there are no requirements on how long a well can be temporary abandoned, neither in NORSOK D-010 or UKG. The number of temporary abandoned wells is becoming a big challenge (see section 2.3.12), and will continue to be as long as no requirements on duration exist. A temporary abandoned well should be permanently abandoned as soon as possible unless a particular reason for not doing so. It is anticipated that this will be included in the next revision of NORSOK D-010, where a well cannot be temporary abandoned for more than 3 years.

Another issue in relation to temporary P&A is the need for an inspection scheme. This is not mentioned in NORSOK D-010, only that the A-annulus shall be monitored for abandonments lasting more than 1 year, but an alternative to this can be setting a deep set well barrier [3]. In UKG it is stated that operators should consider physical inspections of long-term abandoned wells with a justified frequency. The same should apply for the NCS, and operators should go through all temporary abandoned wells on a regular basis to evaluate the integrity status and plans for future use, as recommended from PSA. This is important as temporary abandoned wells with degraded or failed barriers can be a safety hazard.

6.1.10 P&A Categorization

In section 3.3.6 (and 3.3.7 for temporary P&A) a system included in the UKG for categorizing wells to be abandoned was presented. A P&A operation is divided in three phases, with each phase given a specific number (0-4) describing the complexity, resulting in a code to indicate the work scope of the operation. In addition, a set of tables can be found in *Guideline on Well Abandonment Cost Estimation* which helps determine the complexity (code 0-4) of each phase by assessing the characteristics for a given phase (see table 6). As for now, there is no such system in Norway. The reasons are unknown, but one main reason can be that operators and regulators on Norwegian sector feel they do not have enough experience with P&A to create such a system. Despite this, considerations should be made to establish a similar system for NORSOK D-010, and the system in the UKG can be used as basis. The gains for implementing such a system can be:

- Indicates the work scope of a P&A operation in a simple and effective way
- Can be used on both well and field level, and works for all type of wells
- Used for high level cost estimation
- Provide a clear guideline to when it is possible to use vessels or rigs
- Using this system makes it easy to compare P&A operations, both internally and against other operators
- Can be used for establishing “best practices” for different P&A codes

In addition, a study should be conducted on the NCS to establish the number of wells needing to be abandoned in the future (similar to a UK study from 2008), and using this type of categorizing system would easily visualize the scope and complexity of the P&A work waiting.

6.1.11 P&A cost estimation

Oil & Gas UK published in 2011 a guideline to estimate P&A cost, as described in section 3.3.8. The guideline was based on industry best practice, and was made to have an advisory and common document on how to estimate abandonment cost. The method uses the defined P&A

phases and coding system, and applies this into cost estimation. Many operators estimate cost of P&A operations using methods that is made for general drilling and well activities. P&A operations are very different from general drilling and well activities, and introduce several challenges that is unique for well abandonment. That is why having a method for estimating cost for well abandonment based on industry experience could be highly beneficial. As P&A operations often are very complex and vary from well to well, probabilistic modeling on both duration and cost should be used as this takes into account risks and unforeseen events.

Another interesting feature included in this guideline is the description of estimated accuracy in relation to P&A proximity. This describes how the cost estimates can change and the number of wells that should be included in the methodology as COP approaches. A description of this is included for more than 10 years until expected COP. This is a very important issue, as cost estimates would be more accurate if starting early. Cost estimates should start many years prior to planned well abandonment, maybe as much as 10 years. These estimated would have been updated several times before actual operations commence. This would lead to cost estimations of higher quality, and as P&A is all about cost, it is very important to have accurate estimates.

6.2 Technology advances

There is an industry hesitance in implementing new technology and methods. This is understandable as conventional technology is still providing high profits, and the cost of trying new methods and failing often makes operators steer away from these. But P&A is something completely different. Unlike e.g. drilling operations which has the goal of creating value, P&A adds no value and is exclusively an expense. That is why there is a great need for new technology and methods, as the conventional ways of performing P&A operations are not economically sustainable in the future. A selection of new and alternative technology was presented in this thesis, and will now be discussed further for each P&A phase.

6.2.1 Reservoir Abandonment (Phase 1)

As described in section 2.3.4, re-establishing WBEs is an extremely challenging operation. It is highly time consuming, and all the generated swarf can cause serious damage throughout the well. If eliminating milling operations all together a lot of time and money will be saved, in addition to no generated swarf. The *HydraWash* system presented in 4.2.1 is one of the more interesting technological solutions to this problem. Of the 44 plugs installed using this system, an average of 243 days was saved, with an average of 7,5 days saved for the 1 trip system per well, and 6 days for the 2 trip system. In addition an estimated 176 ton of swarf was avoided, and all the plugs were accepted as well barriers. The potential using this system is significant, but some issues need to be solved before the full potential is accomplished:

- Find a way to install and test two independent barriers in one trip.
- Longer perforation guns
- Data should be compared between operators to find optimal operational parameters (benchmarking)
- How well inclination and other factors like annulus fluid affect the tool efficiency
- More emphasis on risks, what can go wrong using this system?
- Using HydraWash with coiled tubing
- The possibility of using this tool from LWIs for subsea wells
- How to optimize the use of the *HydraArchimedes* tool

Especially being able to use HydraWash with CT in the future is interesting. The example cases in section 5.1 showed how both P&A operations could in theory be performed offline if this was possible.

Another issue with regards to reservoir abandonment is the use of alternative materials to cement. Two different materials were presented in section 4.2.2, Sandaband and Thermaset. Tests have showed that both materials meet NORSOK D-010 requirements; in addition they have some clear advantages over cement. For Sandaband, the biggest benefit is the adaptability against downhole environment. The wellbore will experience a variety of shear stresses which can exceed material yield point and deform these, or in the end they can fracture. When this happens to Sandaband, the material starts acting as a fluid which re-shapes instead of fracturing. This is an extremely important property, since the downhole conditions will change over time, and barriers should be able to withstand this change. The same goes for ThermaSet, which have superior mechanical properties compared to cement, making it a better alternative in relation to long-term integrity. Even though both materials have documented properties superior to cement, the biggest challenge is the inability to actually use them in the field. Cement has been used for over 100 years in this industry, making it difficult for new materials to compete. The industry should start testing materials like Sandaband and ThermaSet in the field to conclude if they work, find their limitations, and in the end create several “success cases” so that the industry becomes confident in their use. If well barriers starts failing after abandonment, the operators are required to re-abandon wells, something that would be catastrophic economically, and this should justify the higher material cost of Thermaset and Sandaband. In addition (also discussed in 6.1.5), a guideline on how to qualify materials for permanent abandonment of wells should be created for the NCS, similar to the *Guidelines on qualification of materials for the suspension and abandonment of wells* (Sandaband and ThermaSet are included). This actually encourage the use of other isolation material, and having an industry accepted guideline on how to qualify alternative materials would make it easier for operators to use them here on the NCS.

6.2.2 Intermediate Abandonment (Phase 2)

Phase 2 starts after the reservoir has been plugged with two barriers. Two tools were described for this phase, both with very different tasks.

The wireline conveyed pulling of tubing described in section 4.3.1 is a method of removing the production tubing (can also be done in phase 1 according to UKG definition). It is common that the derrick performs this operation on platforms, which takes away the rig’s potential to perform other operations like drilling. And on some platforms the drilling equipment is removed, meaning that tubing retrieval equipment needs to be mobilized. If wireline could perform the whole operation, the use of the derrick or the need to mobilize special equipment to pull tubing would be eliminated. As for now, using only wireline would need very small intervals of tubing to be cut and pulled because of weight limitations, something that would be highly time consuming. The method Aker Well Solutions presented use a separate line or hollow wireline to inject gas into a closed tubing section to replace the heavy fluid and create a buoyancy effect which greatly reduces the effective tubing weight, making it possible to pull longer sections. This means no need for the derrick to retrieve tubing, and thereby performing this operation offline. The method is only in a development phase at best, but it shows how new ways of thinking and innovation can make P&A operations significantly more effective in the future.

The Suspended Well Abandonment Tool, SWAT, presented in section 4.3.2 has already been used to complete phase 2 abandonment on over 100 wells. It is still to be used on the NCS, but the wave of subsea wells needing to be abandoned in the future makes it very relevant. The SWAT has two main features that make it highly attractive; it can be deployed from a RLWI, and can cement through multiple annuli. Its track record is already proven when it comes to setting the surface barrier; the only question is how to fulfill its full potential. The limitations of the tool were mentioned in section 4.3.2, and solving two of them would greatly improve the tools usage area. These are the working depth, and that it cannot be used to install barriers against shallow formations since it does not have the required well control qualification. Solving this would make it possible to set barriers against shallower formations (if present,) eliminating the need to pull casing to facilitate the barriers, making it possible for RLWIs to perform the whole phase 2 abandonment using the SWAT. In addition, if using the SWAT in batch operations, being able to leave wells while WOC and doing the cement operation on other wells could be beneficial. Here the distance between wells in question need to be considered since all plugs need to be tested after cement has set, but for e.g. several wells existing in a template this could be an advantage. But despite the limitations, there is no doubt that the SWAT should be used for future subsea abandonment jobs on the NCS.

6.2.3 Wellhead and conductor removal (Phase 3)

Phase 3 abandonment starts after all the barriers has been installed. NORSOK D-010 requires that no parts protrudes the seabed after abandonment, meaning that wells needs to be cut at some distance below seabed. Traditionally this has been done with either cutting knifes, which can worn out and often cannot cut through multiple strings simultaneously, or explosives witch is less controllable and introduce HSE issues. Technology using abrasive water jet cutting was presented in section 4.4. This system is very effective as it can cut through multiple strings simultaneously, have no HSE issues, and can be used rigless. Especially the fact that the system can be deployed from RLWIs to perform phase 3 abandonment of subsea wells (modular set up for platform wells) is highly beneficial. As a significant number of subsea wells need to be permanently abandonment on the NCS in the future, it is clear that this type of system is very interesting (The Subsea Wellhead Picker has already been used on the NCS). It should be considered for all abandonment projects, both for subsea wells and on platforms.

6.3 Use of rig and vessels in P&A

For permanent well abandonment the desire is to perform as many operations rigless, both for platform and subsea wells. Chapter 5 showed how alternative technology can eliminate or limit the use of the rig for platform P&A, and how operations can be moved away from semi-subs to LWIs for subsea P&A. This will be further discussed in this section.

6.3.1 Platform abandonment

As Statoil has the drilling rig in place on most of their platforms, the ultimate goal for platform P&A is to perform operations offline. In situations where this is not feasible, the goal should be utilizing the rig in the most effective way. In section 5.1 one simple and one complex scenario was presented to show how platform abandonment can be improved by using non-conventional technology. The key changes with regards to platform P&A are:

- Bullhead cement when possible. If not possible use coiled tubing to displace cement to release the drilling rig

- For re-establishing annular cement, methods eliminating the need to mill can greatly improve P&A operations. HydraWash has a great track-record and Statoil should strongly consider using this when possible
- Pulling tubing and casing is one of the main challenges with regards to performing the whole P&A operation offline. There is technology that can perform this operation rigless currently, with Weatherford's Pulling and Jacking unit briefly mentioned in section 5.1.1. *The wireline conveyed pulling of tubing* presented in this thesis is one future method that can be used to pull tubing by using wireline and gas injection
- Use SABRE or similar systems to remove the wellhead

Other improvements with regards to platform P&A should be:

- Logs able to log through multiple casings
- Using formation as barriers
- If having to mill, methods for leaving the swarf downhole

6.3.2 Subsea abandonment

As mentioned several times in this thesis, one of the main goals for subsea P&A is moving operations away from semi-submersibles. Semi-submersibles are highly expensive, they are often unavailable, and should be used for drilling new wells. Three different cases were described in section 5.2; one were a semi-sub completed all phases, one where a RLWI was used to partly abandon a well, and one where LWIs completed the whole P&A operation. The different vessels that can be used in subsea abandonment were presented in section 4.1.

Based on current technology, partial abandonment using LWIs is the most probable method of moving operations away from semi-subs. A typical operation was described in section 5.2.2, with a semi-sub completing phase 1 abandonment, including installing barriers against the reservoir and pulling tubing. In many situations barriers are needed against shallower formations, resulting in removal of casing strings. In that case the semi-submersible would pull the casing strings and then install the barriers, before RLWIs complete the rest of the operations. Two solutions already discussed, the SWOT and abrasive water cutting system, completes phase 2 and 3 abandonment respectively from a RLWI. It should also be mentioned that Statoil has used RLWIs in P&A operations on TOGI, to prepare wells for before phase 1 abandonment. But for future P&A jobs, the SWOT and abrasive water cutting systems shows how RLWIs can be used effectively to complete two phases of P&A.

One of the main reasons for RLWI's inability to perform full P&A operations (see section 5.2.3) is the lack of riser. LWIs able to use risers were presented in section 4.1.1, classified as category A+ and A++ vessels. These can work on live wells and circulate cement with CT, making it possible to perform phase 1 abandonment. But because of technology not fully developed, the use of these vessels present a difficult decision between smaller low cost vessels with high risk systems in category A+ and A++ vessels, versus larger high cost vessels with simple low risk systems in category C vessels (semi-subs). In addition, category A vessel's inability to pull tubing and casing strings makes it very difficult for them to complete all phases of P&A. As the situation is now, there are many technological gaps that need to be filled in order for LWIs to perform full subsea abandonment. It should be noted that for P&A operations of high complexity, the need for semi-sub will probably always be present.

For subsea abandonment P&A should be organized in batch campaigns to optimize operations. Mobilizing rigs and vessels is an extra cost, and the transit from shore to relevant wells takes time, so for every additional well included in a batch operation, extra mobilization (and de-mobilization) is eliminated. This is why when planning P&A operations, as many wells as possible should be included, being restricted by the maximum wells a vessel can abandon before needing to demobilize with regards to deck space, equipment, etc.

Category B vessels introduced in section 4.1.2 are intended to fill the gap between category A and C vessels. These are a smaller semi-submersibles, with a lower cost (approx. 60% of conventional semi-subs, see figure 29). Category B vessels are intended for intervention work, but because of the P&A wave approaching its application area in relation to P&A should be studied. The company Helixesg has a similar category B vessel called the Q4000 which has been used to perform P&A jobs in the GoM.

Something that should be strongly considered is constructing vessels specifically made for subsea P&A. The future need for subsea abandonment will be so significant that constructing this type of vessel could be beneficial. Having a cheaper solution to semi-subs, with similar mobility as LWIs, and properties made specifically for P&A could revolutionize subsea abandonment. These would probably be a more expensive alternative compared to the traditional RLWIs, but should still present a great cost reduction compared to semi-subs. In addition, the semi-subs would be released for value-creating operations like drilling new wells. For this to be possible several issues need to be sorted out:

- If using a riser, how to compensate high motions from a smaller vessel.
- Having a vessel that safely handles the interface between high pressure hydrocarbons and low pressures on deck.
- How the LWI vessel could perform cement placement deep in the well, preferably without using riser.
    - In this regard CT is very interesting, and would greatly increase the application area of RLWIs
    - Having sufficient well control equipment without using riser is a big challenge
- If needing to re-establish barriers, there is a big challenge in making this possible from LWIs.
- How to solve the challenge of pulling tubing/casing when necessary from LWIs. Making it possible to cement through multiple annulus against deep formations with a tool similar to SWAT could eliminate the need to pull tubing all together.
    - Pulling tubing without the use of riser would be a challenge with regards to well control
    - Where to place all the pulled tubing/casing could be an issue with regards to deck space

- How to perform as many operations as possible without the need to demobilize at shore for new operations.
- New technology evolving for P&A operations should be made applicable for use from LWIs (if possible).

6.4 Requirements and technology

In this thesis requirements and guidelines used on Norwegian and UK sector have been analyzed. In addition, unconventional technology and methods for use in P&A operations have been described. On the NCS, permanent abandonment of wells is a fairly recent issue, but it will cause a lot of headache in the near future. The only way for P&A to become economically sustainable is by implementing new and better technology. As the “plug wave” is to hit the NCS over the next decades, it is very important that operators start using alternative technology and methods, especially in an industry that is known to be very hesitant in doing so. One way of making this easier would be if NORSOK D-010 encouraged the use of alternative methods. It is hard to point out exactly how this should be done, but the UK guideline on qualification of isolation material can be an example. In section 6.1.5 it was described how one of the guideline’s aims was to encourage the use of alternative materials. When it comes to technology, it is difficult to determine how NORSOK D-010 or other PSA published documents could encourage the use of alternative methods and technology, but some suggestions are:

- Re-evaluate the use of the term *shall.* This can restrict the thinking of operators, and result in using conventional technology.
- NORSOK D-010 should be written more elaborated and detailed, but without taking away operator freedom to themselves decide what is best in a given example. The UKG is an example of how this can be done.
- A PSA created document describing alternative and proven technology should be considered, including operations, benefits, limitations, best practices, parameters, etc. Having an industry accepted document that encourages the use of new and alternative technology would probably make it easier for operators to take these in use.

7. Conclusions

One of the main goals with this thesis was to find possible improvements on requirements and guidelines in Norway, with main focus on comparing NORSOK D-010 with guidelines used in UK. Another goal was to look how alternative technology and vessel use can improve P&A operations. The conclusions in this chapter will be based on the discussions conducted in chapter 6. Not everything discussed will be included.

7.1 Possible improvements on NORSOK D-010

After analyzing NORSOK D-010 and UKG to find possible improvements for NORSOK D-010, the following changes are recommended:

- There should first and foremost be considerations in creating a separate standard for P&A, similarly to UK, as P&A in many ways differ compared to other well activities.
- Make NORSOK-010 a more elaborated, but advisory document. As for now NORSOK D-010 is very prescriptive. The UKG can be a good reference, and should be done in cooperation with the industry to find a satisfactory end product.
- Remove the term *shall* in describing requirements in NORSOK D-010. Use the term *should* instead as it advises operators according to best industry practice. The use of *shall* is a very strict, and as NORSOK D-010 should be more advisory, this can take away much of this effect
- Be more precise in describing terminology;
    - The use of *eternity* should be removed from NORSOK D-010 as it is a term that is very difficult to relate to. Operators know the consequence if barriers fail so they will do their outmost to maintain isolation.
    - The use of the term *reservoir*, which in NORSOK D-010 is defined as a permeable formation with flow potential and/or hydrocarbons present, should be described clearer.
    - *Permeability* should also be defined more clearly in NORSOK D-010. Sometimes a formation can have hydrocarbons present, but with flow unlikely. In this case one

barrier can be sufficient. In UKG, a permeable zone is considered hydrocarbon-bearing if *moveable* hydrocarbons are present.

- There should be done more scientific work on barrier height. Currently this seems like an empirical number which varies from country to country, and therefore research is needed to find a scientific acceptable height.
- NORSOK D-010 should be more elaborating when it comes to verifying casing cement. Pressure testing annulus between two perforations separated with 50 meters can be a method to verify this instead of logging. Alternative information should in combination be able to replace logging. One can use longer intervals as substitute to the lack of logging (as discussed in 6.1.3).
- Using formations (like shale) as a part of barriers should be included in NORSOK D-010. Especially guidelines on how to verify this as part of a permanent barrier is important.
- Consider removing recommended cutting depth for wellhead removal. Stating that no parts of the well should ever protrude the seabed should be sufficient. With regards to platform abandonment where structures are left behind, the requirement should be that casing never extends above any remaining structures.
- Guideline to determine future reservoir pressure should be included. If using lower reservoir pressure than virgin pressures barriers can be installed at shallower depths.
- There should be strong emphasis on initial well design taking into account future abandonment in NORSOK D-010. This can make operators more aware of this issue, and designing wells with P&A in mind can eliminate most technical difficulties for future abandonment, and prevent high costs for operators.
- There should be strict requirements on how long a well can be temporary abandoned.
- A system to categorize wells that is to be abandoned should be included in NORSOK D-010. The UKG model with P&A phases and codes should be used as basis in constructing such a system.

7.2 Other documents with regards to P&A

In addition to UKG, Oil & Gas UK has released two other guidelines in relation to P&A; one being guidelines to qualify isolation material, and the other cost estimation. In Norway, PSA should in cooperation with the industry consider doing the same. The author recommends three additional documents in relation to P&A;

- A guideline on qualifying materials used in barriers made by an expert group with high knowledge in this area should be made, similar to the UK version. Will make it easier for operators to try out alternatives to cement.
- As in UK, a guideline on estimating well abandonment cost should be made. As P&A is all about cost, there should be a common method that can be used as a basis when implementing cost estimation methods for P&A. This would replace methods that were originally made for estimating cost of general drilling and well activities. Having a categorizing system for P&A is very important in this context.
- Making a document that highlights new and alternative technology should be considered. This would typically describe best practices and different operations. Should be updated on a yearly basis. The goal of this document would be to encourage operators to try out alternative technology.

7.3 Use of alternative technology and methods

Many times in this thesis it has been stated that new and better ways of doing operations is the primary way of making P&A economically sustainable in the future. Several alternative technological solutions were presented. This was to show how different methods can be used in P&A operations to solve several challenges. To conclude this was learned:

- Replace milling as the main method of re-establishing barrier elements behind casing strings. HydraWash is a tool presented in this thesis that can be used.
- Try out alternatives to cement in barriers to find more suited materials with relation to P&A. Sandaband and ThermaSet were introduced, both having properties superior to cement.

- Replace the use of rigs to pull tubing and casing. A future method using wireline and gas injection was presented for pulling tubing (Wireline conveyed pulling of tubing). In addition, Weatherford's Pulling and Jacking unit was briefly mentioned as a method to perform offline tubing and casing retrieval.
- The SWAT is a tool described that can simplify phase 2 subsea abandonment significantly. The ability to cement through multiple annuli when installing the surface barrier, and that it can be deployed from RLWIs, are two highly beneficial properties.
- Use abrasive water cutting systems when removing wellheads. It is very effective as it can cut through several strings simultaneously and pull all together, and is very HSE friendly. Can be performed rigless both for platform and subsea P&A.

7.4 Performing operations rigless

Rigless abandonment is one of the main goals for the future. Both platform and subsea abandonment have been discussed with some main points being:

- For platform P&A the goal is performing operations offline. Technology and methods eliminating the need to use drilling rigs should be prioritized. A wider use of coiled tubing, and integrating this with new technology can be a major step in completing this goal.
- For subsea P&A the future goal is moving operations away from semi-submersibles to LWIs, with the ultimate goal being full well abandonment using LWIs. There are many challenges that need to be solved to make this a reality, but it should be possible in the future. Some findings in this thesis are:
  - Two technology solutions presented in this thesis, the SWAT and SABRE system, shows that RLWIs can be used effectively to complete phase 2 and 3 abandonment.
  - The two main technical challenges are displacing cement from LWIs (not surface barrier), and pulling tubing or casing.
  - Using LWIs with risers would give a wider range of possibilities, and can be the solution to perform full P&A operations. There are LWIs already that can use risers, but for now these operations remain highly complex.

- Being able to use coiled tubing from RLWIs can be a major contributor in performing full subsea P&A riserless.
- Abandonment campaigns should be planned for seasons where the probability for rough weather is lower, preferably during summer.
- Plan abandonment of subsea wells as batch operations. For each well that is included, extra mobilization is eliminated.
- Research on the use of Statoil's new category B vessel in P&A operations should be conducted. Helixesg has a similar vessel that has been used for well abandonment in the GoM.
- Strong considerations should be made to construct vessels purely for P&A operations. As the future need for well abandonment is so extensive, having a LWI vessel that is specifically made for P&A and can perform full well abandonment would be very beneficial.

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Appendix A

Permanent barrier, primary				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	Pressure test	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement, or measure to volume confirm depth of firm barrier, subject to risk assessment	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Open hole	Tagging	N/A	N/A	N/A

Table 17: Verification of primary barrier [11]

Permanent barrier, secondary				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	FIT or liner lap Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	As above. pressure test may be omitted if there is insufficient space to verify independently on volumes	Good cement bond, minimum 100 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Open hole	Tagging	N/A	N/A	N/A

Table 18: Verification of secondary barrier [11]

Permanent combination barrier				
Barrier type	Verification			
	Well bore / tubing		Annulus	
	Position	Sealing capability	Position	Sealing capability
Through-tubing	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Through-tubing on a mechanical barrier	Tag	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately (see Section 7.10)	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test
Cased hole	Tag	Pressure test	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	Pressure test or inflow test
Cased hole on a mechanical barrier	Tag cement	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 200 ft, if previously logged or 1,000 ft above base of barrier if estimated from differential pressures	FIT or liner lap Pressure test or inflow test

Table 19: Verification of combination barrier [11]