



Universitetet
i Stavanger

FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study programme/specialisation: M.Sc. Offshore Technology – Marine and Subsea Technology	Spring semester, 2017 Open
Author: Anne Lene Blom Øksnes	<i>Anne Lene B. Øksnes</i>
Programme coordinator: Ove Tobias Gudmestad Supervisor(s): Jostein Aleksandersen, UiS	
Title of master's thesis: Permanent Plugging and Abandonment - An identification and discussion of technologies and the differences in UKCS and NCS regulations	
Credits: 30	
Keywords: Plug and Abandonment Regulations NORSOK D-010 Oil and Gas UK DNV GL- RP-E103 New technology Improvements NCS	Number of pages: 102 + Appendices: 4 Stavanger, 13.06.17



PERMANENT PLUGGING AND ABANDONMENT

– An identification and discussion of
technologies and the differences in UKCS and
NCS regulations

Anne Lene Blom Øksnes

Acknowledgements

I would like to take this opportunity to thank some people who have aided me in writing this thesis. Firstly, I would like to extend my gratitude to my supervisor at the University of Stavanger, Jostein Aleksandersen for suggesting a topic and giving me valuable and structured feedback and assistance during the process of writing my thesis.

I would also like to acknowledge the companies Interwell, Island Offshore and HydraWell for providing me with the needed insight and information to describe their technologies.

Lastly, I must extend a thank you to my co-students and friends for giving me the needed breaks, perspective and motivation for finishing this thesis.

Abstract

There is a large number of wells on the Norwegian Continental Shelf that need to be permanently plugged and abandoned (P&A) within the next decades. As P&A does not provide any income, it is very important to develop cost-effective methods to perform the operations. This thesis gives a brief presentation of how plug and abandonment operations are performed and which challenges that exist within the field. Further some selected technologies which are under development or recently implemented in the industry are presented and discussed. In addition to the technological challenges, it is also likely that the regulations can play a role in achieving more effective solutions.

The main objective of this thesis has been to analyse the Norwegian standard that is valid for P&A operations and compare it to both the existing guidelines on the UK continental shelf and to a risk-based perspective proposed by DNV GL. The UK industry is more experienced than the Norwegian and operate in similar waters, therefore it makes sense to compare the two to find ways of improving NORSOK D-010. The risk-based perspective provides a new approach to P&A which is in line with the overall trends of the industry where risk-based decision making is becoming increasingly emphasised. The comparison of these three documents resulted in several suggestions for improving the NORSOK D-010, and for additional guidelines that might be useful on the NCS.

Another aspect of this thesis has been to investigate how new technologies can be used to improve P&A activities as this is likely to be the main contributor for more cost-efficient operations. The overall goal of the technologies presented is to eliminate the need for a rig as this is one of the highest costs in P&A. Also, rigs are better used for drilling where there exists potential revenue for the operators. Some of the technologies have been implemented whereas others struggle to achieve qualification and be tested. The industry is conservative and there is a certain reluctance towards trying new technologies, when there are already solutions that works implemented. This thesis suggest that part of the problem lies within the phrasing and requirements found in NORSOK D-010 which appears to be very strict.

The result of this thesis is a list of recommendations on how to improve the NORSOK D-010 to close the gap between UKCS and NCS regulations. It further provides recommendations for how to better open for alternative technologies and methods to be implemented in P&A operations.

Abbreviations

ALARP	As Low As Reasonably Practicable
BHA	Bottom Hole Assembly
BOP	Blow Out Preventer
COP	Cessation of Production
CT	Coiled Tubing
DCR	The offshore installation and wells (design & construction etc) 1996
DPMV	Dynamically Positioned Monohull Vessel
HLV	Heavy lift vessel
HXT	Horizontal x-mas tree
IOSS	Island Offshore Subsea
LLP	Lower Lubricator Package
LWI	Light Well Intervention
MD	Measured Depth
MO(D)U	Mobile Offshore (Drilling) Unit
OWCT	Open Water Coil Tubing
P&A	Plug and Abandonment
PSA	Petroleum Safety Authority
RLWI	Riserless Well Intervention
TOC	Top of Cement
VXT	Vertical x-mas tree
WL	Wireline
XT	X-mas tree

Table of content

Acknowledgements	i
Abstract	ii
Abbreviations	iii
List of figures	vi
List of tables	vii
1 Introduction.....	1
1.1 Objectives	2
1.2 Thesis structure	2
2 Vessels used in offshore operations.....	3
3 Plug and Abandonment – What it is and how it is done	5
3.1 P&A current status	6
3.2 Procedure for P&A operations	6
3.2.1 Killing and securing the well.....	7
3.2.2 Pulling of tubing.....	8
3.2.3 Logging the Cement.....	8
3.2.4 Removal of wellhead and other equipment above seabed	10
3.3 Challenges with P&A	10
3.3.1 Current situation	10
3.3.2 Availability of vessels to perform P&A	10
3.3.3 Available information about wells and their condition.....	11
3.3.4 Logging of cement	11
3.3.5 Removal of control lines.....	12
3.3.6 Removal of casing to set cement plug.....	12
3.3.7 Cooperation within market	13
3.3.8 Temporarily abandoned wells.....	14
3.3.9 Regulations and requirements	14
3.4 New technology.....	16
3.4.1 Perforate, wash and cement to establish well barrier	16
3.4.2 Alternatives to cement as barrier.....	18
3.4.3 Pulling of tubing by using wireline/coiled tubing.....	20
3.4.4 Interwell rig-less P&A	21
3.4.5 Open Water Coiled Tubing	22
4 Requirements and Regulations	25
4.1 NORSOK D-010 – Well integrity in drilling and well operations.....	25

4.1.1	Definitions	26
4.1.2	Abandonment design	26
4.1.3	Well barrier.....	27
4.1.4	Well barrier element	29
4.1.5	Length requirements.....	30
4.1.6	Verification	31
4.1.7	Removing equipment above seabed.....	32
4.1.8	Well barrier schematics.....	32
4.1.9	Examples of different options for setting the plug	34
4.1.10	Methods to establish cement plug.....	35
4.1.11	Other topics.....	35
4.2	Oil and Gas UK – Guidelines for the abandonment of wells	37
4.2.1	Definitions	37
4.2.2	Material requirements for permanent barriers	38
4.2.3	Zones with flow potential.....	40
4.2.4	Permanent barriers	41
4.2.5	Verification of a permanent barrier	48
4.2.6	Special considerations for abandonment.....	50
4.2.7	Phases of well abandonment	54
4.2.8	Appendices	55
4.2.9	Guidelines on Well Abandonment Cost Estimation	56
4.3	DNV GL – RP-E103 – Risk based abandonment of offshore wells.....	61
4.3.1	Section 1 – introduction	61
4.3.2	Section 2 – Risk assessment framework for well abandonment design.....	63
4.4	Matrix summarizing requirements in different documents.....	70
5	Discussion.....	71
5.1	Differences in regulations and guidelines	71
5.1.1	Structure and intent of the documents.....	71
5.1.2	Phrasing/wording used.....	72
5.1.3	Well barriers	72
5.1.4	Materials used as barriers	73
5.1.5	Verification of barriers	74
5.1.6	Categorization of wells	76
5.1.7	Cost Estimation.....	77
5.2	Considerations of P&A in initial well design.....	78
5.3	Incorporation of risk-based perspective	79

5.4	Technological developments.....	81
5.4.1	Cooperation and combinations of technologies	81
5.4.2	The PWC tool.....	81
5.4.3	The OWCT system and potential combinations.....	82
5.4.4	Alternatives to cement as barrier.....	84
5.4.5	Interwell solution	85
5.5	Eliminating the use of rig in P&A operations	86
6	Conclusions and recommendations	88
6.1	General	88
6.2	Recommendations for NORSOK D-0101	88
6.3	Recommendations for technology and methods.....	90
	References.....	91
	Appendix.....	93

List of figures

Figure 1:	Illustration of different vessel categories [5].	4
Figure 2:	Simple illustration of a well before and after P&A.....	6
Figure 3:	Simple well barrier schematic	9
Figure 4:	Section Milling operation [13].....	13
Figure 5:	DNV GL qualification process [16].....	15
Figure 6:	Time saved using PWC compared to Section Milling [17].....	16
Figure 7:	The HydraWash tool [18]	17
Figure 8:	Sandaband yield properties [21]	20
Figure 9:	Conventional versus open water coiled tubing [32]	23
Figure 10:	Challenges for doing P&A from LWI vessels on subsea wells [33].....	24
Figure 11:	Illustration of cross-sectional requirement for permanent well barriers [6].....	28
Figure 12:	Permanent abandonment of an open hole and inside casing plugs [6]	31
Figure 13:	Example WBS with EAC referral [6].....	33
Figure 14:	Example of WBSs [6]	34
Figure 15:	Examples of different options for setting plugs for permanent abandonment [6]	35
Figure 16:	Schematic of permanent barrier [34].....	41
Figure 17:	General requirements for well abandonment [34].....	42
Figure 18:	Illustration of geological setting for permanent barriers [34]	43
Figure 19:	Length requirements for permanent barriers [34]	44
Figure 20:	Open hole P&A where internal pressure is less than casing shoe fracture pressure [34] ...	44
Figure 21:	Example of open hole barriers where two zones need isolation from each other but does not exceed the casing shoe fracture pressure [34].....	45
Figure 22:	Example of open hole barrier where potential internal pressure exceeds casing shoe fracture pressure [34, 36].....	45
Figure 23:	Example of side-tracked well with open hole section [34]	46
Figure 24:	Casing alone is not accepted as lateral permanent barrier [34]	47

Figure 25: Example of cased hole abandonment [34].....	48
Figure 26: Abandonment of high angle well [34].....	51
Figure 27: Liner lap cementation [34]	52
Figure 28: Through-tubing abandonment [34]	53
Figure 29: Illustration of cost estimation process [37].....	60
Figure 30: The main system components of P&A wells [39].....	63
Figure 31: Risk Context for P&A [39].....	64
Figure 32: Examples of well abandonment designs in DNV GL- RP-E103 [39].....	67

List of tables

Table 1: Applications for open water coiled tubing	23
Table 2: Well Barriers depth position.....	27
Table 3: Content of well barrier element acceptance criteria tables [6]	29
Table 4: Cement plug length requirements [6]	30
Table 5: Level of accuracy required as COP approaches [37]	58
Table 6: Matrix for categorizing well abandonment [37]	59
Table 7: Example of well categorization [37]	59
Table 8: Categorization of flow potential in hydrocarbon-bearing formations	65
Table 9: Matrix summarizing main differences in documents.....	70

1 Introduction

When oil and gas offshore fields mature and wells no longer produce enough to be economically sustainable, even with intervention, the wells eventually need to be permanently plugged and abandoned. This applies to all types of wells drilled whether its exploration, development, injection, production, platform or subsea wells. The number of wells are increasing each year and more than 6000 wells exist on the Norwegian Continental Shelf (NCS) alone [1]. Out of these, 3281 are production wells and 680 are injection wells, the remaining are appraisal, wildcat and observation wells [2].

Plug and abandonment (P&A) is when a well is killed and shut in permanently by installing barriers, and all equipment on the seabed is removed. The goal of P&A is to remove all traces of oil and gas activity and ensure that the environment will never experience any harm due to hydrocarbon leakages. The procedure does not provide any income for the operators and it is both costly and time-consuming. Therefore it is highly attractive if the methods and technology involved in P&A can be improved and become more cost-effective. On the NCS there has been little focus on P&A due to the fact that the industry is fairly young in this region, and wells have continued producing beyond their expected lifetime. However, over the next 20-30 year there will be a large increase in wells needing to be permanently abandoned and hence the technology and methodology used should be reviewed.

Traditionally, plug and abandonment has required that drilling rigs, such as semi-submersible mobile offshore drilling units (MODU), are freed from the drilling schedule and sent to the well site where a riser system is connected from the rig to the subsea wellhead. These P&A campaigns are costly, although some rig rates have decreased with a lower oil price. The reason for the high costs is the complexity of manning, mobilising and maintaining such high specification rigs, combined with the time taken for them to transit and conduct the necessary work.

With the recent drop in oil price, and increasing need for P&A, operators are investigating solutions which could result in more cost-effective operations, at the same time as not compromising HSE goals and regulations. This has resulted in new technologies and methods being developed, but due to the industry being conservative several promising solutions have not been tested infield. Another aspect is that the requirements on the NCS are very strict, and the newer developments does not necessarily fit within the framework of the current regulations. Thus, the standards should also be reviewed even though improved technology is likely to be the main contributor to solving the P&A challenge.

In previous revisions of the NORSOK D-010 several differences and potential improvements compared to the UK Guideline has been identified. This thesis aims to investigate the most recent revisions of both documents and identify which differences still exist and suggest potential measures that could be taken to improve NORSOK D-010 based on these differences. The UK sector is much more experienced than the Norwegian with respect to P&A and it seems reasonable that the NCS could take some learning from the UK industry.

The main objective of this thesis will be to identify and discuss differences between the Norwegian and UK sector with regards to performing P&A, and give an overview of new technology and methods proposed for making the operation more cost-effective.

1.1 Objectives

A portion of this thesis will be devoted to describing challenges with P&A, where the technology used and new technologies being developed to overcome some of the challenges will be addressed. Further, the main focus will be on identifying the differences in methodologies (legislative requirements and regulations) on the Norwegian Continental Shelf versus the UK Continental Shelf. There will be a discussion regarding which differences exist and what improvements could potentially be made to the Norwegian regulation based on the more experienced UK industry. In addition, a risk-based perspective introduced by DNV GL will be presented and included in the discussion of improvements to NORSOK D-010.

1.2 Thesis structure

This thesis covers the following topics:

Chapter 2 – Vessels used in offshore operations.

Chapter 3 – overview of current status within P&A, procedure for P&A operations, challenges with P&A and new technologies being developed.

Chapter 4 – presentation of the regulative documents NORSOK D-010, UK Guidelines for the abandonment of wells and DNV GL-RP-E103. A matrix summarizing the differences between the documents.

Chapter 5 – Discussion of the differences in regulations, the importance of the initial well design and incorporating of a risk-based perspective.

Chapter 6 – Conclusions and recommendations.

2 Vessels used in offshore operations

DNV GL classifies offshore drilling and support units based on a set of variables. The vessels commonly used for both intervention and P&A can be divided into three categories; Mobile offshore drilling unit (MODU), well intervention unit (WIU) type 1 and well intervention unit Type 2 [3]. Type 1 and type 2 vessel based approach provides cost savings when compared to the hire of a rig.

MODUs or cat. C, are conventional rigs with low pressure risers which traditionally is used for drilling and completing wells. In addition, these units are equipped with workover equipment which implies that they can perform full P&A operations and a variety of well interventions. However, they are historically associated with high costs, up to 40-50% of P&A total cost, and they require more time for mobilization and rig-up which makes them a less attractive option.

The WIU type 2 or cat. B vessel, have some of the same capabilities as a MODU but tend to have a lighter set-up. This unit also uses a riser from the vessel to the subsea XT and are able to handle return flow of hydrocarbons. The cost of this method is slightly lower than a conventional rig (MODU) but cannot be compared to the savings of using a WIU type 1 vessel. WIU type 2 vessels/rigs have high pressure small bore riser and are traditionally necessary to perform heavy interventions like coiled tubing.

WIU type 1 or cat. A, is commonly known as riserless light well intervention (RLWI) vessel and has traditionally been used in wireline operations. These vessels are generally cheaper and use less time to mobilize and rig-up than the other two types of intervention vessels. WIU type 1 enables equipment to be temporarily installed when needed and hence create flexibility in which operations they can perform. The day rate for the type 1 vessel (incl. fuel) is approximately 30%-40% of the cost associated with a rig [4].

Figure 1 illustrates the differences in the offshore units typically used in offshore operations [5].

Comments:

1. The recent drop in oil price has made the MODUs more affordable and available than previous years.
2. If a vessel is to be directly involved with a live well then there is a need to have the Acknowledgement of Compliance (AoC). There are 3 vessels that have this: Island Wellserver, Island Frontier and Island Constructor.
3. Although a LWI vessel is likely to mobilize, get to location and perform an operation faster than a conventional rig, it may also be more inclined to experience down-time due to waiting

on weather. Waiting on weather is when the conditions on site are too severe for the intended operation to be carried out, e.g. high waves, strong currents or winds.

4. Cat. A are typically dynamically positioned monohull vessels (DPMV) which will experience more acceleration and vessel movement than an anchored rig and hence the system must be able to handle more movement, especially in terms of heave. The vessel will also experience different motion at the bow, midship and stern of the ship. The moonpool is located midship where the ship experiences the smallest heave motion. The DP system will ensure that the vessel is kept on location with the thrusters actively counteracting the effect of some of the movements. The heave motion however, requires additional equipment in terms of passive and active heave compensation to counteract the effects of waves.

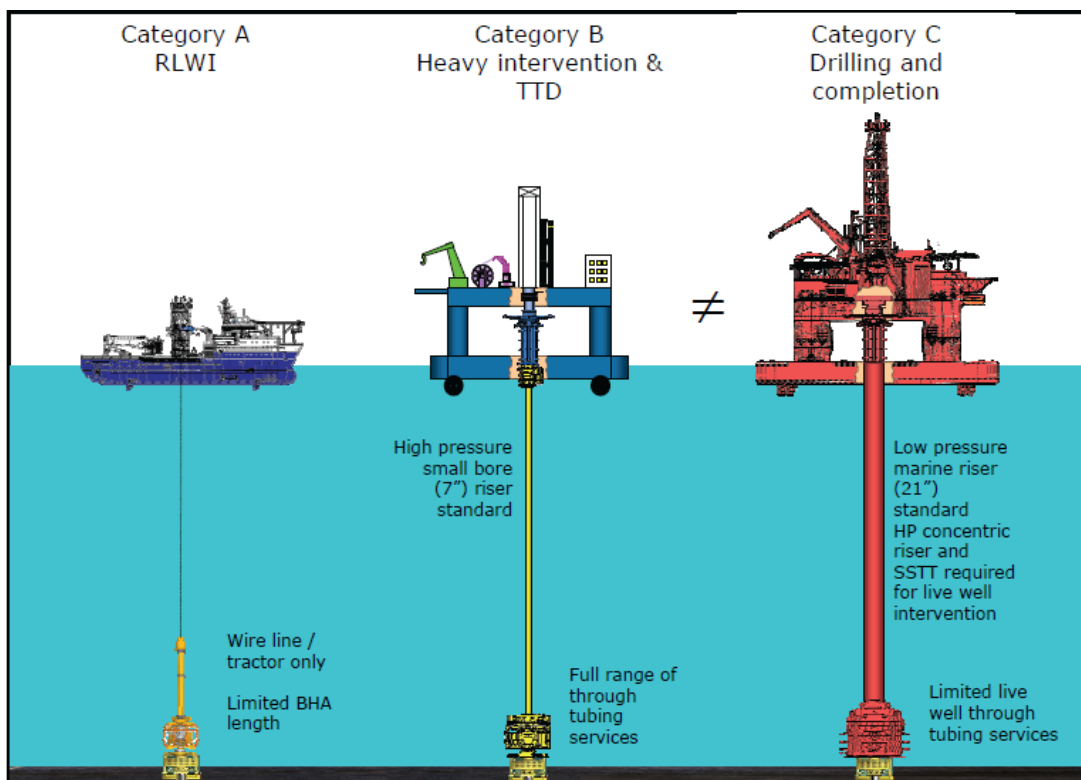


Figure 1: Illustration of different vessel categories [5].

3 Plug and Abandonment – What it is and how it is done

Plug and abandonment (P&A) is the name of the operation performed on a well at the end of its life when it has served its purpose. This applies to all wells drilled whether they are exploration, production or injection wells. The reason for doing P&A is that the environment shall never be negatively influenced by the remnants of the oil and gas activity, with specific focus on preventing hydrocarbons to leak from formations into the ocean environment.

A P&A operation can be temporarily or permanent. A temporary P&A is performed when the intent is to re-enter the well at a later stage. The focus of this thesis is permanent P&A and the term P&A refers to permanent plug and abandonment unless otherwise stated. P&A is defined as a well status where the intent is to never use or re-enter the well again. Due to this it is crucial to have a long-term perspective when choosing the equipment and barrier used for the operation. The equipment used to plug the well needs to withstand the effect of any foreseeable chemical and geological processes that may occur [6].

There are mainly two reasons for plugging a well. One is that the section of a reservoir is no longer productive but the main wellbore is to be re-used by drilling a side-track. The other reason for plugging is that the entire well, including all side-tracks, is no longer deemed to be economically feasible and needs to be shut in. It is the latter that will be presented and discussed further in this thesis.

A general illustration of a well before and after P&A can be seen in Figure 2.

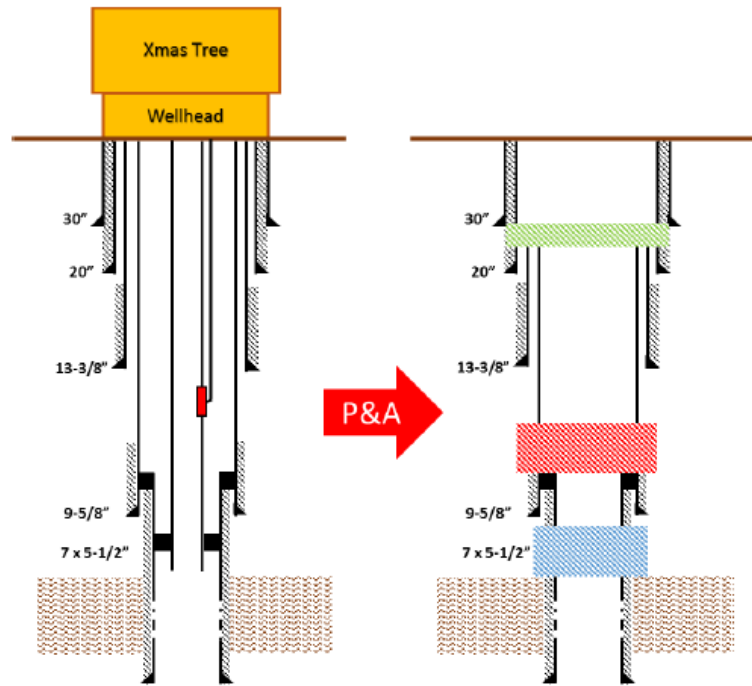


Figure 2: Simple illustration of a well before and after P&A

3.1 P&A current status

In 2013 Martin Straume, leader of the Norwegian Oil & Gas P&A Forum, presented a time estimate for plugging of the wells on the NCS. Based on an estimate of 3000 wells to plug, along with a 35-days average for each well and with 15 rigs working fulltime he estimated that it would take approximately 20 years to successfully plug them, with current technology. However, based on the activity in the last ten years (144 wells/year), it is estimated that another 2880 wells will be drilled during the 20-year period, which means that it would take 15 rigs a total of 40 years to plug all the wells. Assuming the current technological status of the industry persists, the final bill could be as much as 876 billion NOK, which is split 22% by the operator and 78% by the government [7]. This estimate is not very promising and it illustrates that measures need to be taken so that P&A operations can become more efficient.

3.2 Procedure for P&A operations

In the following a general procedure for P&A operation will be described. The main steps outlined in the following applies to vertical XT (VXT), for horizontal ones the procedure will be different. Some of the 10 points below is explained in the next sub-sections.

1. Mobilization of vessel and subsea equipment needed
2. Connect to XT

3. Kill and secure the well
4. Install Tubing hanger plugs
5. Handling of subsea tree
6. Run BOP and Marine Riser
7. Pull Tubing Hanger and tubing
8. Run cement log
9. Plug and abandon well – barrier plugs
10. Open hole to surface plug
11. Cut and retrieve wellhead

Before starting the P&A operation it is required to know the potential inflow from both reservoir and overburden. In addition to the producing reservoir, other formations with flow potential at shallower depths must be identified and taken care of.

3.2.1 Killing and securing the well

The first stage of an P&A operation once the vessel is in place is to connect the vessel to the XT and proceed to kill the well. Kill the well is the term used for ensuring that the hydrocarbon flow from the well is stopped. The well is killed by pumping a heavy fluid/mud downhole which ensures overbalance against reservoir pressure. This eliminates the need for topside pressure control equipment. A deep-set mechanical plug is usually installed to act as a temporary barrier, and/or as basis for cement plug before the tubing is cut and pulled. The cutting can be done by various methods [8].

After this, tubing hanger plugs are installed in production bore and annulus to ensure a minimum of two barriers while removing the XT, which is the next step.

As mentioned there are differences between a horizontal and a vertical XT with the main difference being that a HXT is installed on top of the wellhead before the tubing and tubing hanger is installed whereas the tubing and tubing hanger is installed inside the wellhead for a VXT. This means that a HXT needs to be pulled in the end of the P&A operation, after tubing is pulled and barriers is in place. A VXT need to be retrieved earlier in the P&A operation sequence and is removed after the well is secured with two barriers, and before pulling of tubing.

Usage of BOP and Marine Riser are standard for semi-submersible rig operations to ensure sufficient barriers are in place when doing P&A operations such as removing tubing hanger and tubing. The BOP is installed after removal of the VXT and before pulling the tubing. If the well has a HXT the BOP is installed on top of the HXT.

3.2.2 Pulling of tubing

The tubing can be left in hole but in most cases it is pulled due to several reasons, where the main one is that the control lines attached to the tubing may cause a vertical leak path through the barrier. If the tubing were to be left in hole, proper verification methods to check the quality of the cement barrier is required but to date there is no such method deemed good enough for multiple casings [8].

The general procedure for a well with a VXT is to cut the tubing above the production packer (if not retrievable), remove the XT, install BOP and then pull the tubing through the BOP by using drill-pipe. This is a big job that requires heavy machinery as the pulling weight may vary between 100 and 150 tons.

3.2.3 Logging the Cement

After the tubing is pulled it is customary to log the cement in the well to check the quality of the existing cement job on the outside of the lower completion before installing barriers to plug the reservoir. If the log shows good quality then the cement plug barrier can be established inside the existing casing. If the log shows poor quality or there is no cement outside casing the existing casing must be removed, traditionally by a procedure called section milling, to ensure a proper barrier are in place. The barrier must extend through the full cross section of the well, including all annulus, and seal in both vertical and horizontal direction [6].

Section milling is one of the challenges with P&A which makes the operation more complex and will be addressed later under section 3.3.6.

When plugging the reservoir there shall be two permanent barriers in place between the surface and potential source of inflow, according to NORSOK D-010, rev 4 [6]. One is called the primary barrier and the other is called secondary barrier. The primary well barrier, shown in its normal working station, is usually marked with blue. This is the first barrier to prevent unwanted flow of fluid and it provides closure of the well barrier envelope. The secondary well barrier, shown in its ultimate stage, is usually marked with red. This barrier is often located outside the primary well barrier and its main function is to withstand any well pressure or flow of fluid in case the primary well barrier fails. Figure 3 shows a simple well barrier schematic of an abandoned well.

All permanent barriers have to be above the potential source of inflow which means that if a well has several side-tracks/sections, the primary and secondary barrier must be above the different side-tracks. A barrier within a section will not count as a permanent barrier towards the surface but it is common to cement across the individual perforation sections in addition to placing permanent barriers. As the barrier has to extend to the full cross-section of a well, the cement plug shall be set

at a depth where formation integrity is higher than potential pressure below, i.e. where the cement log has verified good quality of cement on the outside of the casing. The casing alone is not sufficient to act as a permanent well barrier element (WBE) [6].

After the permanent WBEs are in place, they have to be tested from above to verify their integrity.

For permanently abandoned wells it is usually not enough with two well barriers. It is often also required to have an open hole to surface barrier (marked in green). The open hole to surface barrier shall isolate the hole from the surface and act as the final barrier against harmful flow reaching the ocean. A typical procedure for this phase is to cut and retrieve necessary casings, install a bridge plug as barrier fundament and then establish a cement barrier.

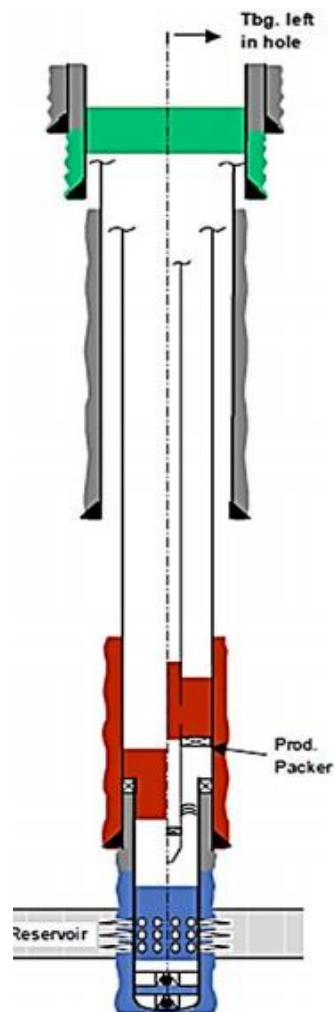


Figure 3: Simple well barrier schematic

3.2.4 Removal of wellhead and other equipment above seabed

When a well is permanently abandoned there should be no trace of the well left at the seabed. Due to this, seabed equipment shall be removed and the wellhead and casings shall be cut at a depth which ensures no stick-up or conflict with the marine environment in the future [6].

3.3 Challenges with P&A

There exist several challenges with P&A related to both technology and costs. Each well drilled has unique properties which calls for individual evaluation and the operations can become complex. In the North Sea there is a high number of wells that are depleting which results in a “wave” of wells needing to be P&A in the next decades. This is known as the “plug wave” in the industry. As P&A does not create any revenue for the operators, it is necessary to find more cost-effective solutions to ensure the sustainability for the operators. To do this, there are several challenges that is being addressed and need to be solved in the near future.

3.3.1 Current situation

The NCS is relatively young with fields starting to produce in the 1970’s and due to this P&A has not been very high on the agenda in the past. However, several fields are now maturing and this has resulted in an increased focus on P&A and how to do it in the most cost-effective manner while maintaining safety for personnel and environment. Especially the focus on costs has increased in the last few years after the dramatic drop in oil price the industry has experienced. P&A is a high expenditure operation which does not create any revenue for the operators and this has resulted in some reluctance towards technology development within the field. It has been easier “to sit on the fence” and wait for others to develop solutions one can adopt. But it is becoming more and more apparent that the best solution is probably for several companies to share technology and develop new methods together.

According to Oil & Gas UK’s there are over 1800 wells that needs to be permanently P&A’s on the NCS and UKCS over the next ten years [9]. Other sources states that in total there are over 2500 wells on the NCS which will need to be abandoned at some stage, with 3,000 more wells planned to be drilled in the future[7]. In the UK, close to 5,000 offshore wells will need P&A [10].

3.3.2 Availability of vessels to perform P&A

P&A are traditionally performed by a rig due to the heavy work included such as pulling of tubing and milling operations. However, rigs are associated with high day rates and time-consuming mobilization and operations. Even with the recent drop in oil price, and decrease in drilling activity on the NCS the

day-rates of a rig is still considerable higher than that of an LWI vessel. In addition, with the large quantity of wells in need of future P&A there are not enough rigs available to carry out the operations. With current technology it takes an average of 35 days to plug a well. With 15 rig working full-time it could take 40 years to plug all wells (existing and planned) on the NCS [7]. Therefore, companies should focus on moving P&A activities away from rigs to smaller vessels. That way rigs are free to focus on drilling activities which has higher potential revenue for the operators.

3.3.3 Available information about wells and their condition

Among the wells that need plug and abandonment there are big differences in the data available. This is because the wells have different age and as a result there has been different requirements to recording of data. Also, wells have changed owner during their lifetime and sometimes not all data are passed along. Specifically, information regarding cement behind casing is often lacking and can be a big problem.

Other information that is important to have is potential pressure build-up in annulus as trapped gas rapidly can lead to loss of well control when e.g. cutting casing for wellhead removal. For subsea wells, it is impossible to monitor all annulus and thus it might be necessary to have pressure control equipment activated to relieve any pressure in annuli between casings before pulling the casing/wellhead when performing the cuts/perforations.

Due to the lack of information on well condition, P&A requires extensive preparation work before commencing the operations.

3.3.4 Logging of cement

As mentioned previously logging of the cement quality is one of the standard operations performed during P&A. To date, there are no proven way of logging through multiple casings which results in casing and tubing needing to be pulled to verify the cement behind the casings. This is a cost- and time-consuming operation which usually involves a rig.

If it was possible to log through several casings it could potentially save operators a significant amount of time and money as it could prevent them from installing plugs where it is not necessary (good cement behind casings). There are currently several companies working on this problem to both improve existing technology and develop new ones. Logging through two or more casing strings is a key missing technology for both rig-based and rig-less P&A operations.

In addition to logging through multiple casings, other challenges related to logging of cement exist such as [11]:

- Lack of data from older wells
- Even though jobs are known to be successful the logs can show bad cement quality
- Repeated logs show different results for same job
- Interpretation is often subjective as expertise to properly interpret logs are somewhat lacking within supply companies.

3.3.5 Removal of control lines

Another challenge has been the control lines located on the outside of the production tubing and how to pull these. As the control line is a potential vertical leak path if they are left in the wellbore, it is currently normal practice to pull the tubing with the control lines attached. However, there is a demand for developing technology which could cut specific sections of the control lines so that the whole lines and tubing would not need to be pulled, while still ensuring barrier across the whole cross-section [8]. Several companies and clever minds are investigating potential solutions to this challenge. Proposed solutions include cutting both tubing and control lines, cutting sections of it to allow for full cross-section barriers, cutting and pushing the debris down with a mechanical plug that can further be used as base for barrier to mention some [8]. Description of these technologies will not be included in this thesis.

3.3.6 Removal of casing to set cement plug

Often it proves to be impossible to place an approved cement plug across the entire cross-section of the wellbore without removing the casing. This is due to issues such as a stuck casing, a poor cement job behind the casing causing leaks or that the cement is missing and there is no way to access the last open hole section. The traditional method is to remove the casing by section milling but this is a complex operation which the industry is trying to avoid if they can due to associated disadvantages.

Section milling is an operation which aims to create a clear section of formation where a WBE can be set by grinding away a specific interval of the casing and contamination behind it. Figure 4 illustrates the operation. During the operation a tool is run into the well to a desired depth. Once positioned, a rotational force will make the tool will cut into the casing body by utilizing knives/blades. Once the cut is completely through, the milling is initiated. Usually milling is done downwards so that the weight applied from the drill-string pushes the tool down [12].

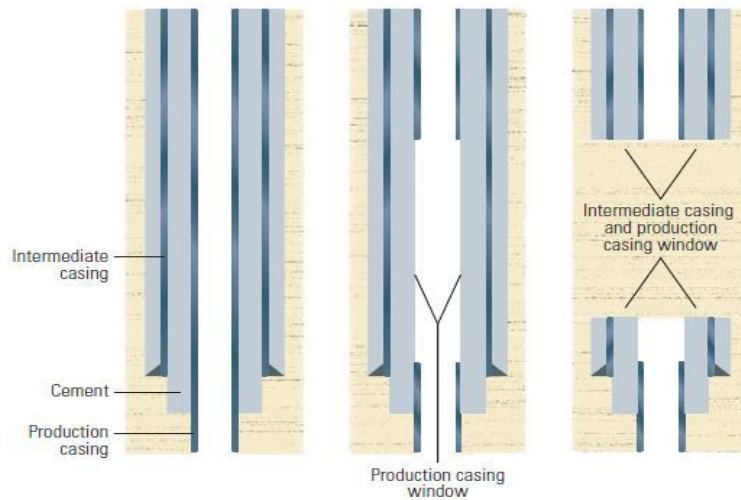


Figure 4: Section Milling operation [13]

As mentioned one does not wish to perform section milling if it can be avoided. This is due to reasons such as [14]:

1. It is time consuming which will lead to high cost.
2. It generates swarf. Swarf is the cuttings/metal shavings that accompanies the milling operation. Swarf is difficult to handle and can potentially cause serious problems downhole in addition to harming equipment such as the BOP when circulated out. To avoid well integrity issues because of a failed BOP, it has to be dismantled, inspected and repaired at considerable expenses after milling operations.
3. The operation causes excessive vibrations that could harm equipment in the bottom hole assembly (BHA).
4. HSE challenges are created due to the swarf and debris handling and disposal. The metal returns have sharp surfaces which means that personal protective equipment must be worn to avoid damages to eyes and hands. Environmental issues arise from the point of collection on the rig to the final disposal site. Issues include material documentation and classification, handling, containment, tracking and transport.

Due to the negative implications associated with section milling several new technologies has been developed in recent years which eliminates the need to perform section milling in P&A activities. The alternatives are described in section 0.

3.3.7 Cooperation within market

P&A has been a somewhat neglected part of offshore oil and gas operations in terms of coming up with new, and more cost-effective solutions for several years. But as the field has been given more attention from the public and authorities in terms of requirements, and with the increasing number

of wells in need of P&A, the industry has realized that attention to the field is long overdue. Based on this several efforts have been made to develop new technologies and increase the sharing of knowledge across company, and country, borders. Some examples are the initiative to start yearly P&A seminars where challenges and recent development can be presented and discussed, and Joint Industry Projects (JIP) to both develop and test new technologies on pilot wells. These initiatives for sharing of knowledge is a key to overcoming the challenges related to P&A.

3.3.8 Temporarily abandoned wells

Previously there has not been any regulations for how long a well can be temporarily abandoned. In the newest revision of the NORSOK D-010 this has changed and temporary abandonment is defined as with or without monitoring. If a well is temporarily abandoned with monitoring, there is no maximum abandonment period. If a well is temporarily abandoned *without monitoring* however, there is a maximum period of three years. The lack of regulations in the past has led to a number of wells being temporarily abandoned, even though they are not planned to be re-used, because there is no value creation with P&A. It has been easy to postpone permanent P&A operations and focus more on value creating areas like drilling.

Now that the regulation for temporarily abandonment has changed, it means that there are several wells which has been temporarily abandoned for a long time that are now in need of permanent abandonment within a relatively short period of time. To avoid situations like this in the future there are some measures identified by the PSA that operator should take such as [15]:

- New wells (exploration wells) should be permanently P&A as soon as finished if they are not planned to be re-used in the future
- Temporary P&A should be temporary and not be a long-run solution for wells
- Wells that are temporarily abandoned should be evaluated on a regular basis where the integrity status and potential plans for future use should be evaluated.

3.3.9 Regulations and requirements

Different countries, and parts of countries, has different governmental requirements and regulations that the operators need to deal with when performing P&A, in addition to company specific requirements. This means that operators, and their associations, may need to alter their methods for performing P&A based on where in the world the well is located.

In addition, the current regulations/standards might be a challenge for the new technologies that are being developed. The new technologies/methods may not fit entirely within the scope of/be covered by the current standards and regulations. As a result, the companies cannot apply the requirements directly even though methods have been proven to work in a safe manner through pilot-wells and other testing. This means that the system need to go through a qualification process before it can be implemented on a live subsea well to perform well intervention or P&A.

As an example, Island Offshore is using DNV-RP-A203 as guidance for the qualification process of their new Open Water Coiled Tubing (OWCT) system, with the figure below showing the pathway [16]. The process is done in close collaboration with DNV GL and PTIL to ensure that the steps and measures taken are documented and can be traced back to evaluate the approach used. Interwell is also cooperating closely with DNV GL. Both these systems will be explained later in this thesis.

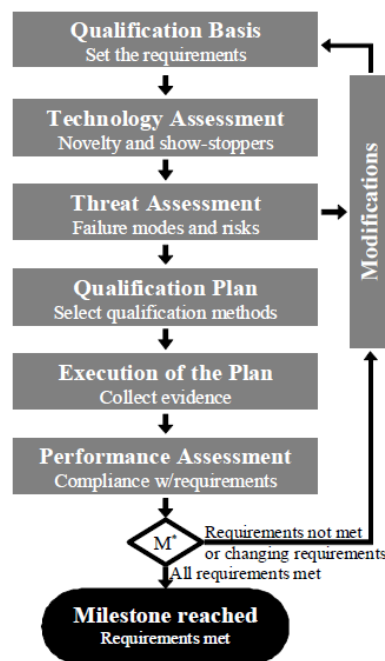


Figure 5: DNV GL qualification process [16]

This thesis will not cover the qualification of new technologies but will devote a significant portion to the differences that exists between guidelines on the UKCS and the NCS. In addition, a new perspective on P&A operations delivered by DNV GL will be discussed. The traditional way of regulating P&A is from a prescriptive point of view whereas DNV GL is proposing to look at it from a risk-based perspective. This topic will be further addressed in chapters 4 and 5 .

3.4 New technology

As mentioned there has been an increased focus on P&A operations in recent years as the demand have become more evident. The development has focused on challenges like eliminating the need for rigs and section milling in addition to introducing alternative plugging materials. This section will present some of the new technologies that has emerged, with some of them already being proven while others are still in the design/qualification/testing phase.

3.4.1 Perforate, wash and cement to establish well barrier

Perforate, wash and cement (PWC) is a technology which eliminates the need for section milling in P&A operations. The operational sequence, given in the name, is to perforate the casing rather than to mill it, to wash away cement and/or formation behind it and then to set a cement plug. The operation is performed by drill-pipe or coiled tubing [14]. The method eliminates swarf generation and the casing will be left primarily intact, allowing for a re-entry on a later occasion. The production tubing is cut and pulled, and if there are more than two casings they also have to be removed before the PWC operation can commence.

In this thesis, the PWC system developed by HydraWell will be used to describe the general system and the savings it provides as this system has been accepted and proven in the industry.

Figure 6 below illustrates the time saved when doing PWC compared to section milling. A traditional plugging operation, using section milling, took an average of 10,5 days but when HydraWell introduced PWC the plugging time was reduced by 7,5 days to only 3 days. This saves tens of millions per plug and has changed the way of doing P&A, with one of the biggest time savers being that there is no need for milling the casing [17]. The plug is verified by a pressure test and tagging.

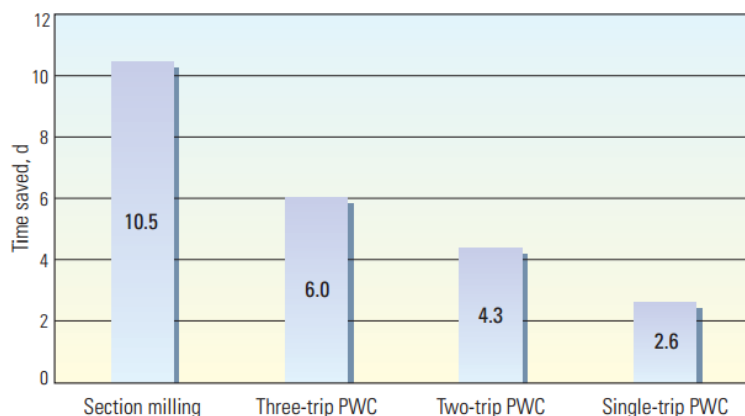


Figure 6: Time saved using PWC compared to Section Milling [17]

The method can clean and cement the annuli in up to two casing strings and uses a tool made of tubing-conveyed perforating guns attached below a wash tool, which sits below a cement stinger.

The tool is run to plug-setting depth and then the guns are fired to perforate the casing. The guns have a disconnect function which drops it after firing. Now, the wash tool is located at the bottom of the BHA. This tool has bypass channels for running in and elastomer cups to direct the flow during washing. Above the wash tool a cement stinger is placed for cementing the section after it is cleaned [13].

The wash tool is used to wash and clean out debris, old mud, barite, old cuttings and cement traces in the annulus behind the casing. The washing is illustrated in Figure 7, with mud flowing from the bottom elastomer cup to clean the annulus and return the debris to surface.

Once washing is complete the tool is moved to the bottom of the perforations and a cement spacer is pumped into the annular space as the tool is pulled upwards. The wash tool is then disconnected from the cement stinger, and the wash tool is pushed to the bottom of perforations and will serve as base for the cementing operation. The wash tool is designed to maintain contact with the casing inner wall.



Figure 7: The HydraWash tool [18]

Following this, the interval is cemented through the stinger. The cement is squeezed into the perforations. Unlike section milling, this system provides a plug that can be verified in the annulus. If this is needed, the plug is drilled out after it has set and a log is run to verify the bond in the annulus. After, a new cement plug has to be placed inside the casing with a new verification according to regulators requirements [13].

HydraWell states that they have run 1 of 200 plugs on CT, the other has been run on drill-string. The challenges with running on CT are [19]:

- Pump rate – creating the necessary lift in well to get the washings out of well
- Rotation during washing. Currently a hydraulic rung indexing tool which rotates the BHA 30 degrees is being used

- Rotation during cementing. HydraWell is working on developing a hydraulic down-hole engine which can rotate the BHA during cementing
- From boat, with or without riser, it must be ensured that the washings from behind the casing is lifted from the well to the boats mud system.

As outlined, the benefits of using a PWC operation over section milling are many. PWC allows for the verification of annulus cement and possibility for re-entry to the well, it provides a safer working environment for the operating personnel and it limits the exposure of swarf and metal associated with milling. It also reduces the need for additional surface handling equipment due to the milling debris, the need for BOP inspection and meets all regulatory requirements. And, it has been proven that significant time and money are saved by using the PWC technique over section milling [17].

Comment: Another potential benefit (to both systems) is if PWC can be incorporated in a rig-less coiled tubing system. This will however be limited by lubricator and toolstring length and the ability to cut if needed in addition to the CT challenges listed above. If using CT, the TCP guns are installed in multiple runs. More on rig-less coiled tubing will follow in section 3.4.5.

3.4.2 Alternatives to cement as barrier

Cement is traditionally used for barrier material but it is not necessarily the best option in terms of properties. Especially as cement is a material which can crack and create leak paths in case of changing pressures and temperature. Alternatives has been investigated and in some cases implemented in recent years. This section will give a presentation of some alternatives to cement as barrier material.

3.4.2.1 Use formation as barrier

A phenomenon which has been noticed and taken advantage of in recent years is that formation can be used as part of external barrier. It was discovered after several bond logs showed solid material behind the casing far above the expected top of cement. In most cases it has been good correlations between shale/clay zones and zones showing bonding which indicates that the shale has sealed off the annular region and that it is the presence of such formation material that resulted in a good bond log response [8]. The formation can be used as part of well barrier if there is a sufficient amount of formation packed on the outside of casing. On a seminar in 2012, Statoil stated to have used this method on more than 100 wells with an 15 MNOK average cost reduction per well [20]. The approach can replace critical operations like section milling and casing pulling but there is a challenge to find logs which can accurately prove and verify the formation as barrier. Also, the presence of

bonded shale cannot be predicted and due to this it shall always be planned for using cement as back up even though formation as barrier is the preferred solution.

3.4.2.2 *Sandaband and ThermaSet*

Sandaband is a sand-slurry which contains a wide variety of particle sizes. The volume of Sandaband is roughly 30% liquid and 70% solid where the liquid is coating the solids particles, and the solids move relatively to each other after the material is in place, and no segregation will occur. The material has Bingham-plastic properties which means that it will act as a fluid when shear stresses exceed the yield stress, this is illustrated in Figure 8. As illustrated the material acts as a solid below the yield point and as a liquid above it. This will cause the material to reshape instead of fracture once subjected to shear stresses above yield point [21].

The material is pumped as a liquid but sets as a solid mass once in place. Because Sandaband is non-reactive, gas tight, not able to fracture and there is no volume shrinking the material avoids well integrity issues. Also, the verification of the plug can start immediately after the total volume has been displaced. This has the potential to save lot of time compared to cement which has to wait for the slurry to set. Verification is performed by mud circulation above and below the expected top of slurry while observing the return over the shakers.

Sandaband is mainly made of quartz and water, making it HSE friendly and it remains unaffected by downhole fluids due to quartz being a thermodynamic stable material. A challenge with Sandaband is that it cannot be set on top of a fluid and thus need a foundation [22].

To summarize, the benefits of using Sandaband in P&A include;

- No need for milling which saves time.
- It is easier to place than cement which save time.
- Does not set up prematurely, meaning less risk is involved.
- There are no losses to formation.
- Non-hazardous and environmentally friendly.
- Ductile and adaptable, no fracture, no leaks.
- No issue with downhole fluid contamination.
- Robust and non-complex, it relies purely on physical properties.

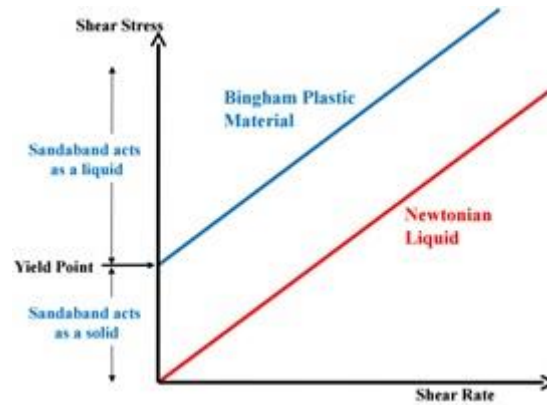


Figure 8: Sandaband yield properties [21]

ThermaSet is another material that can possibly replace cement in P&A operations. ThermaSet is a non-reactive polymer which is 100% particle free and is activated by downhole temperature. Depending on the design it can take from minutes to days for the plug to be thermally activated to set. It is a fluid when pumped but as it hardens it changes properties completely. Compared to cement, ThermaSet has much higher tensile strength, it is more elastic, tolerate temperature expansion and does not crack [23]. ThermaSet can be conveyed by wireline, drill-string, or coiled tubing and be used in all areas of P&A. The biggest challenge with ThermaSet is that it is more expensive than cement. According to a presentation held by WellCem As at the 2012 Plug and Abandonment Seminar in Stavanger the following benefits is valid for ThermaSet [24];

- It is reliable – permanent sealing of reservoirs and plugging of casing/annulus
- Effective – reduction of permeability
- Superior - mechanical properties
- Lasting – high durability.

Comment: The following update has been posted on Sandaband web page [25] and the ramification of this is unclear; “As of April 2017 The company Sandaband Well Plugging has not been able to sustain operations in today's business environment. The Mother Company, Sandaband AS, which is the patent holder will now be point of contact, with the same management in place until further notice.

3.4.3 Pulling of tubing by using wireline/coiled tubing

An approach that was presented at Plug and Abandonment Seminar in 2013 by (then) Aker Well Services is a method that proposed to pull tubing by using wireline or coiled tubing. The author has not succeeded in discovering if the method is still valid after Aker Well Services was sold to EQT VI and restructured to Altus Intervention and Qinterra Technologies in 2014. However, the method will be presented as an option for pulling tubing during P&A operations.

The method presented eliminates the need for using a drilling rig or other heavy equipment. The system presented need a pipe handling system for when tubing come to surface in addition to general wireline equipment. The essence of the method is to inject gas to displace heavier fluid and generate buoyancy effect which will aid in pulling the tubing [26].

The method has the following operational sequence:

- 1) The tubing is cut right below the tubing hanger and the tubing hanger is removed.
- 2) A plug with check valve functionality is installed at the bottom of the cut tubing.
- 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 pulled to surface.

3.4.4 Interwell rig-less P&A

Another advancement within the field of P&A is Interwell ongoing development of a rig-less approach which does not require removal of tubing prior to P&A operation and has no need for drill pipe when placing primary/secondary barriers. The solution is designed and optimized to be conveyed on E-line, wireline or coiled tubing. This unconventional technology aims to restore a reservoir barrier with properties similar to the original cap-rock by essentially melting the in-situ material such as metal, cement and in part formation in an exothermic process. The goal is that this will provide a barrier which is solid in an eternal perspective. The general idea is based on natural magma processes occurring in the earth and trying to copy what happens when magma moves around in the inner channels of the earth before becoming solid rock [27].

The technology is in the development phase and at the time-being Interwell is using pilot wells for testing the system. The testing is being done in close collaboration with DNV GL and regulatory agencies. According to commercial manager at Interwell they are planning to perform approximately 15 pilot wells onshore and the first offshore pilot well on a North Sea platform by end of 2017 or start of 2018. The biggest challenge identified by Interwell is for the technology to fit within the framework of regulations and getting sufficient track record and documentation in place [28]. The following description of the technology is extracted from patent WO 2013135583 A2 which is the only publicly available written material on the technology.

The method can be used for permanent well abandonment or removal of a well element arranged in a well by use of a thermite mixture and consist of the following steps [29]:

- Provide a sufficient amount of heat generating mixture where the amount is customized according to desired operation
- Position the heat generating mixture at the desire depth in the well
- Ignite the mixture and thereby melting the surrounding materials in the well.
- When mixture has burnt out, the melted materials will solidify and form a plug against the formation, comprising of the melted materials.

The method may comprise of positioning a minimum of one high temperature resistant element close to the melting area to protect parts of the well which lie above, below and/or contiguous to the melting position. For P&A operations it may also be placed a permanent plug (e.g. bridge plug) in the well with a high temperature resistance plug above/below it to aid in positioning and protect the rest of the wellbore.

For igniting the heat generating mixture, a timer may be used in connection with the igniting head. Such a function might be useful when several wells in close proximity to each other are being abandoned, e.g. from same template, and the timer in each well can then be set to ignite at the same time, or different times, after the vessel has left location. This will reduce safety risk to personnel.

Comment: The patent states that as the plug created will have other properties than the cement usually used in abandonment, the NORSOK standard requirements may not be relevant for all applications and operations. This is an interesting point and should be seen in relation to the challenges that exist with current regulations and discussion that will follow in this thesis.

3.4.5 Open Water Coiled Tubing

Open water coiled tubing (OWCT) is an approach to P&A and well intervention which has been investigated in recent years but is yet to be utilized on a live well. As the name suggest OWCT is when the CT is run through open water without being protected by a riser. This means that the CT itself is acting as a riser and it is now subjected to environmental loads, and it is a barrier between the well and its surroundings.

Island Offshore Subsea (IOSS) is the company who is believed to have developed the OWCT technology the furthest. IOSS has proven that OWCT can be performed successfully from a monohull vessel through the Rogfast project and a pilot hole drilling for Centrica [30]. For the Rogfast project IOSS drilled core samples using OWCT and for Centrica they drilled a pilot hole to check for shallow gas. The technology had never been utilized in the offshore petroleum-industry before and proved to be a safer and cheaper alternative to traditional drilling. Centrica estimated that they saved about 30 - 50% by using this riser-less method on the Butch field project. These projects did however not require any well integrity control.

If OWCT can be proven successfully on live wells it could be beneficial to utilize the technology for both well intervention and P&A operations, which could make OWCT a preferred solution [31].

For the system being developed by IOSS they believe it can be utilised in the applications presented in Table 1 below.

Table 1: Applications for open water coiled tubing

RLWI services	Scale and sand cleanout
	Stimulation, circulation, fracturing and acidizing
	Cement squeeze
Plug and abandonment	Circulation and cleaning
	Cementing
	Milling
CT drilling	Drilling and coring
	Pilot hole drilling
	Side track and drilling in shallow reservoirs

The basic topsides elements of a CT system are more or less the same whether it's a conventional platform system with dry tree or an OWCT with subsea tree. But, for the OWCT system the pressure control components are moved subsea and placed on top of the XT and wellhead at seabed in contrast to a conventional system which has all the necessary equipment at surface since the wellhead and XT is placed at surface. A basic illustration of this is showed in Figure 9 below.

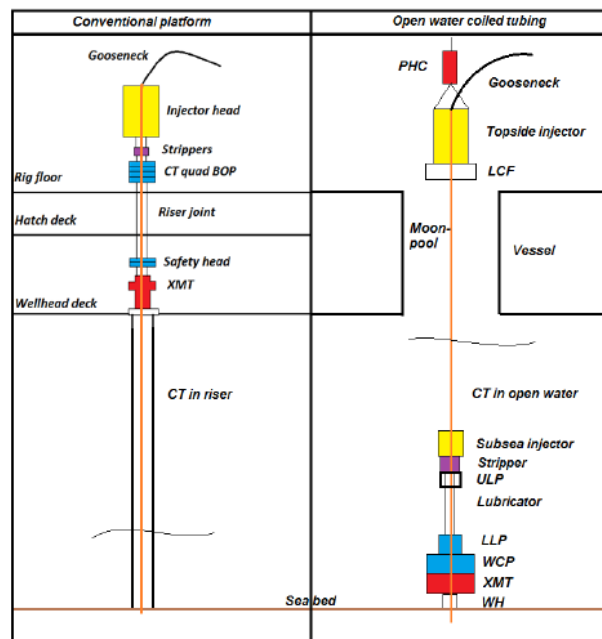


Figure 9: Conventional versus open water coiled tubing [32]

If the OWCT system can be qualified and implemented it can be used to install and place the cement barriers in the annulus or establish a cement plug inside casing when cement behind the casings is verified. By using riserless CT less contamination of the cement will be expected to occur and hence one can obtain improved quality of the cement plug. During the 2016 Plug and Abandonment Seminar, Island Offshore gave a presentation where they outlined the challenges for P&A on subsea completed wells from LWI vessel to be as shown in Figure 10 [33]. In addition to the challenges shown in the figure Island Offshore also pointed out that the methodologies should be challenged, specifically why things are different in the UKCS and the NCS. Some of these challenges has been addressed previously and they will not be further elaborated on in this section although they might need to be solved differently for the OWCT system than for other methods.

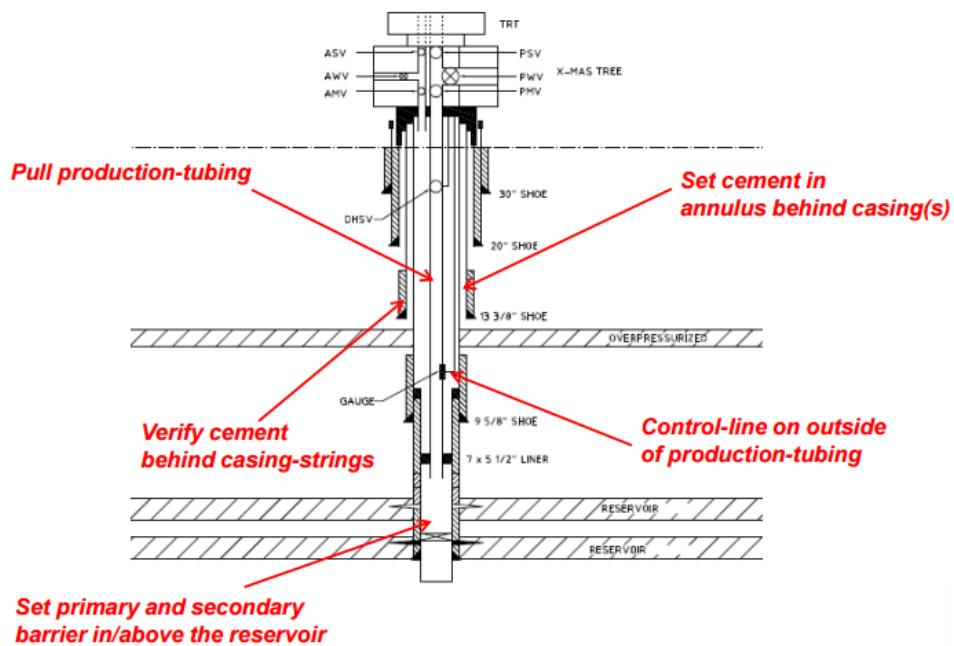


Figure 10: Challenges for doing P&A from LWI vessels on subsea wells [33]

4 Requirements and Regulations

This chapter will give a presentation of the current guidelines and standards being utilized on NCS and UKCS. In addition, a new risk-based perspective being suggested by DNV GL will be presented.

For the NCS the governing standard is the NORSOK D-010 rev 4, *Well integrity in drilling and well operations*. On the UKCS the guideline *Guidelines for the abandonment of wells, issue 5* is used. In 2016 DNV GL published a recommended practice, DNVGL-RP-E103 *Risk-based abandonment of offshore wells* which also will be described in this chapter. Further, the three will be discussed and compared in chapter 5, aiming to propose changes that could be made to the NORSOK D-010 to increase cost-effectiveness of P&A.

4.1 NORSOK D-010 – Well integrity in drilling and well operations

“The NORSOK standards are developed by the Norwegian petroleum industry as a part of the NORSOK initiative and supported by the Norwegian Oil and Gas Association and the Federation of Norwegian Industries. NORSOK standards are administered and issued by Standards Norway. The purpose of NORSOK standards is to contribute to meet the NORSOK goals, e.g. by replacing individual oil company specifications and other industry guidelines and documents for use in existing and future petroleum industry developments.” [6].

NORSOK D-010 focus on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities. The standard focus on establishing well barriers and also covers well integrity management and personnel competence requirements.

The standard is divided into four main scenarios for abandonment activities [6]:

- Suspension of well activities and operations
- Temporary abandonment of wells
- Permanent abandonment of wells
- Permanent abandonment of a section in a well (side-track, slot recovery) to construct a new wellbore with a new geological well target

This thesis will concentrate on the permanent abandonment of wells. However, it is worth mentioning that the standard separates between temporary abandonment with and without monitoring where it states that if there is no monitoring the maximum abandonment period is three

years. If monitoring exists there is no maximum abandonment period. This provides an additional incentive to develop better solutions for permanent abandonment.

4.1.1 Definitions

The following definitions are taken from NORSOK D-010 [6].

Cement – collective term for cement and non-cementitious materials that is used to replace cement

Permanent abandonment – well status where the well is abandoned permanently and will not be used or re-entered again

Permanent well barrier – a well barrier which permanently seals a source of inflow

Reservoir – a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water

Source of inflow – same definition as reservoir

Shall – a strict requirement that are to be followed and no deviation is allowed unless accepted by all involved parties

Should – indicates that among several possibilities one is recommended without mentioning or excluding others, or that a certain course of action is preferred but not required

4.1.2 Abandonment design

The NORSOK D-010 states that all sources of inflow *shall* be identified and documented and all WBE used for plugging of wells shall withstand the load and environmental conditions they may be exposed to for the abandonment period. For permanently abandoned wells the period is eternity.

The design basis should include the following:

- a) Well configuration including depths and specification of formations, casing strings, casing cement, wellbores and side-tracks.
- b) Stratigraphic sequence of each wellbore showing reservoir and information about current and future production potential
- c) Logs, data and information from cementing jobs
- d) Formations with suitable WBE properties
- e) Specific well conditions such as scale build up, casing wear, H₂S, CO₂ etc.

Further the standard gives guidelines for which uncertainties should be accounted for in relation to WBE, different load cases to design for, design factors for temporary abandonment and well control procedures, actions and requirements.

Cutting/perforating the casing and retrieving seal assemblies *shall* be performed with active pressure control equipment in place to prevent uncontrolled flow.

4.1.3 Well barrier

A permanently abandoned well *shall* be plugged with an eternal perspective. When plugging one shall take the effects of any foreseeable chemical and geological processes into account and the eternal perspective with regards to re-charge of formation pressure *shall* be verified and documented. The number of well barriers depends on the source of inflow. NORSOK D-010 states that one well barrier is sufficient for the following situations of inflow;

- Undesirable cross flow between formation zones
- Normally pressured formation with no hydrocarbon and no potential to flow to surface
- Abnormally pressured hydrocarbon formation with no potential to flow to surface

Two well barriers shall be in place when there is;

- Hydrocarbon bearing formations
- Abnormally pressured formation with potential to flow to surface

Table 2 below, copied from NORSOK D-010, states the individual or combined well barriers which shall be installed during P&A [6]. Multiple reservoirs/perforations located within the same pressure regime can be regarded as one reservoir for which a primary and secondary well barrier shall be installed. A well barrier can function as a shared well barrier for more than one wellbore.

Table 2: Well Barriers depth position

Name	Function	Depth position
Primary well barrier	To isolate a source of inflow, formation with normal pressure or over-pressured/impermeable formation from surface/ seabed	The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below
Secondary well barrier	Back-up to the primary well barrier, against a source of inflow	As above
Crossflow well barrier	To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.	As above

Open hole to surface barrier	To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.	No depth requirement with respect to formation integrity
------------------------------	--	--

Permanent well barriers *shall* extend across the full cross section of a well, include all annuli and seal in both horizontal and vertical direction as shown in Figure 11. The well barrier shall be placed adjacent to an impermeable formation with sufficient formation integrity to withstand the maximum expected pressure. Control lines and cables shall not be part of the permanent well barrier, hence these and other downhole equipment must be removed when they can cause loss of well integrity [6].

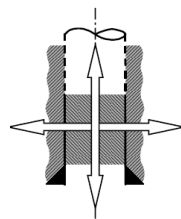


Figure 11: Illustration of cross-sectional requirement for permanent well barriers [6]

4.1.3.1 Material

NORSOK D-010 does not state which material to use, but cement is most common. The standard states that the suitability of plugging material shall be verified and documented. Any degradation of the casing should be considered. The standard states that a permanent well barrier should have the following characteristics:

- a) provide long term integrity (eternal perspective)
- b) impermeable
- c) non-shrinking
- d) able to withstand mechanical loads/impact
- e) resistant to chemicals/ substances (H₂S, CO₂ and hydrocarbons)
- f) ensure bonding to steel
- g) not harmful to the steel tubulars integrity

4.1.3.2 *Casing cement in primary and secondary well barriers*

The same casing cement can become WBEs in both the primary and secondary well barrier if the acceptance criteria for casing cement (EAC 22) are fulfilled. The EAC requires 2 x 30m measured depth (MD) intervals of bonded cement which shall be obtained by logs and verified by qualified personnel. The casing cement is not defined as a common WBE.

Common WBE can be accepted in some cases when it is not possible to establish two independent well barriers but should be avoided if feasible. A risk analysis shall be performed and risk reducing measures applied when a common WBE exists.

4.1.4 *Well barrier element*

Well barrier elements are physical elements which in themselves does not prevent flow but in combination with other WBE’s form a well barrier. To clarify, the previously mentioned well barrier is an envelope of one or several WBE preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the surrounding environment [6]. Both well barrier and WBE shall be designed so that a single failure of a well barrier or WBE cannot lead to an uncontrolled flow of wellbore fluids/gases to the external environment.

NORSOK D-010 includes a specific chapter, 15, devoted to Well barrier element acceptance criteria (EAC). This section contains 59 tables including criteria for cement plug, casing cement, in-situ formation and material plug amongst others. Each table contains information as shown in Table 3. In addition to the EAC in section 15, there are some additional requirements and guidelines for WBE in a permanently abandoned well which will be presented in the following sub-sections.

Table 3: Content of well barrier element acceptance criteria tables [6]

Features	Acceptance Criteria	See
A. Description	Description of the WBE	
B. Function	Describes the main function of the WBE	
C. Design (capacity, rating and function), construction and selection	For WBEs that are constructed in the field (e.g. drilling fluid, cement), this should describe <ul style="list-style-type: none"> a) design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used, b) construction requirements for the WBE or its sub-components, and will in most cases consist of references to normative standards. For WBEs that are pre-manufactured (production packer, DHSV), the focus should be on selection parameters for choosing the right equipment and proper field installation	Name of specific references
D. Initial test and verification	Describes the methodology for verifying the WBE being ready for use and being accepted as part of a well barrier	

E. Use	Describes proper use of the WBE in order for it to maintain its function during execution of activities and operations	
F. Monitoring (regular surveillance, testing and verification)	Describes the methods for verifying that the WBE continues to be intact and fulfils the design criteria	
G. Common WBE	Describes additional criteria to the above when this element is a common WBE	

4.1.5 Length requirements

The standard differentiates between external and internal WBE.

The external WBE, for instance casing cement, shall be verified to ensure a vertical and horizontal seal. At the base of the interval there is a requirement of 50m formation integrity. If the casing cement is verified by logging, it requires an interval with acceptable bonding of minimum 30m for it to act as a permanent external WBE.

The seal of the casing cement shall be re-verified if sustained casing pressure is observed.

The internal WBE, e.g. cement plug, shall extend to the entire interval where there is a verified external WBE and shall be minimum 50m if set on a mechanical plug/cement as a foundation. Otherwise according to EAC 24 of NORSOK D-010, rev 4. EAC 24 provides extensive acceptance criteria for the cement plug. Table 4 below, extracted from EAC 24 explains the length requirements for a cement plug in different scenarios.

Table 4: Cement plug length requirements [6]

Open hole cement plugs	Cased hole cement plugs	Open hole to surface plug (installed in surface casing)
100 m MD with 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 above and below casing shoe.	50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD.	50 m MD if set on a mechanical plug, otherwise 100 m MD

In Figure 12 an example of a simple permanent abandonment is shown. This illustrates if the cement behind the casing is good, where minimum 50 m of cement is known to be in place, or 30 m of cement is verified by logging. The primary plug is set in an open hole, above the reservoir. The plug must be minimum a 100 m long, and it is verified by tagging since it is in an open hole. The secondary plug must be placed inside the casing, across the casing shoe. Minimum 50 m of cement must be

placed in the open hole and minimum 50 m of cement inside casing. This plug is pressure tested since it is placed inside the casing.

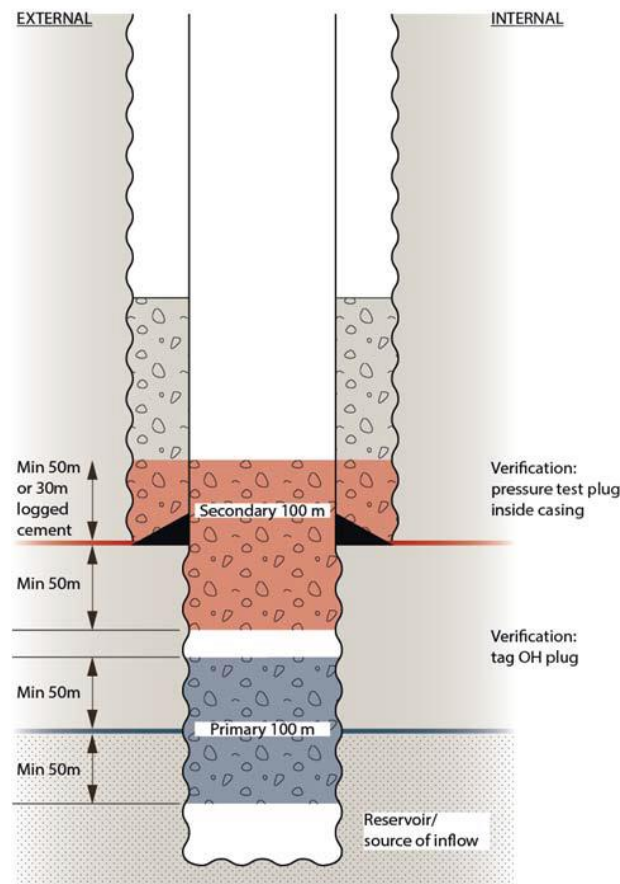


Figure 12: Permanent abandonment of an open hole and inside casing plugs [6]

4.1.6 Verification

The integrity of an installed WBE shall [6]:

- be verified by means of pressure testing by application of differential pressure, or
- when a) is not feasible, be verified by other specified methods

WBE's that require activation shall be function tested. A re-verification should be performed if:

- the condition of any WBE has changed, or:
- there is a change in loads for the remaining life cycle of the well (drilling, completion and production phase)

It is required that the casing cement is verified through logs or using documentation from original cement job like volumes pumped, returns during cementation, etc. The cement sealing ability shall be verified through formation integrity test.

4.1.7 Removing equipment above seabed

For permanently abandoned wells there should be no equipment left at the seabed, nor should any be revealed in the future. Because of this, the wellhead and casings shall be removed below the seabed at a depth which ensures no stick-up in the future [6]. The required cutting depth shall be such that there is no conflict with other marine activities, and one must consider local conditions such as soil and seabed scouring due to sea current when deciding on the cutting depth. In deep water wells it may be acceptable to leave or cover the wellhead. The preferred method for removal of casing/conductor is to use mechanical or abrasive cutting, however the use of explosive is acceptable if the risk to the surroundings is at the same level as conventional cutting

4.1.8 Well barrier schematics

Well barrier schematics (WBS) are practical illustrations of the well showing the different barriers and where they are located. WBS shall be prepared for every well activity and operation, and a final verified WBS shall be in place for the well status upon completing operations. The WBS should contain information such as [6];

- Drawing of barriers and where they are located
- Formation integrity when it is part of the barrier
- Potential sources of inflow
- Listing of WBEs with requirement for verification
- All casing and cement
- Well information such as field, type, name, status etc.
- Any WBE failures
- Important well integrity information

The following examples of WBSs, shown in Figure 13 and Figure 14 are copied from the standard and they represent one possible solution for defining and illustrating the well barriers with WBE [6].

- The primary well barrier is shown in its normal working stage, where the WBEs are exposed to the wellbore pressure. This is shown in blue.
- The secondary well barrier is shown in its ultimate stage, where a WBE (e.g. shear/seal ram/valve) is activated to close the well barrier envelope. This is shown in red.
- An open hole to surface barrier shown in green.

On the side of the illustrations in the standards there is a written statement of which elements are included in the well barriers with reference to the well barrier elements acceptance tables.

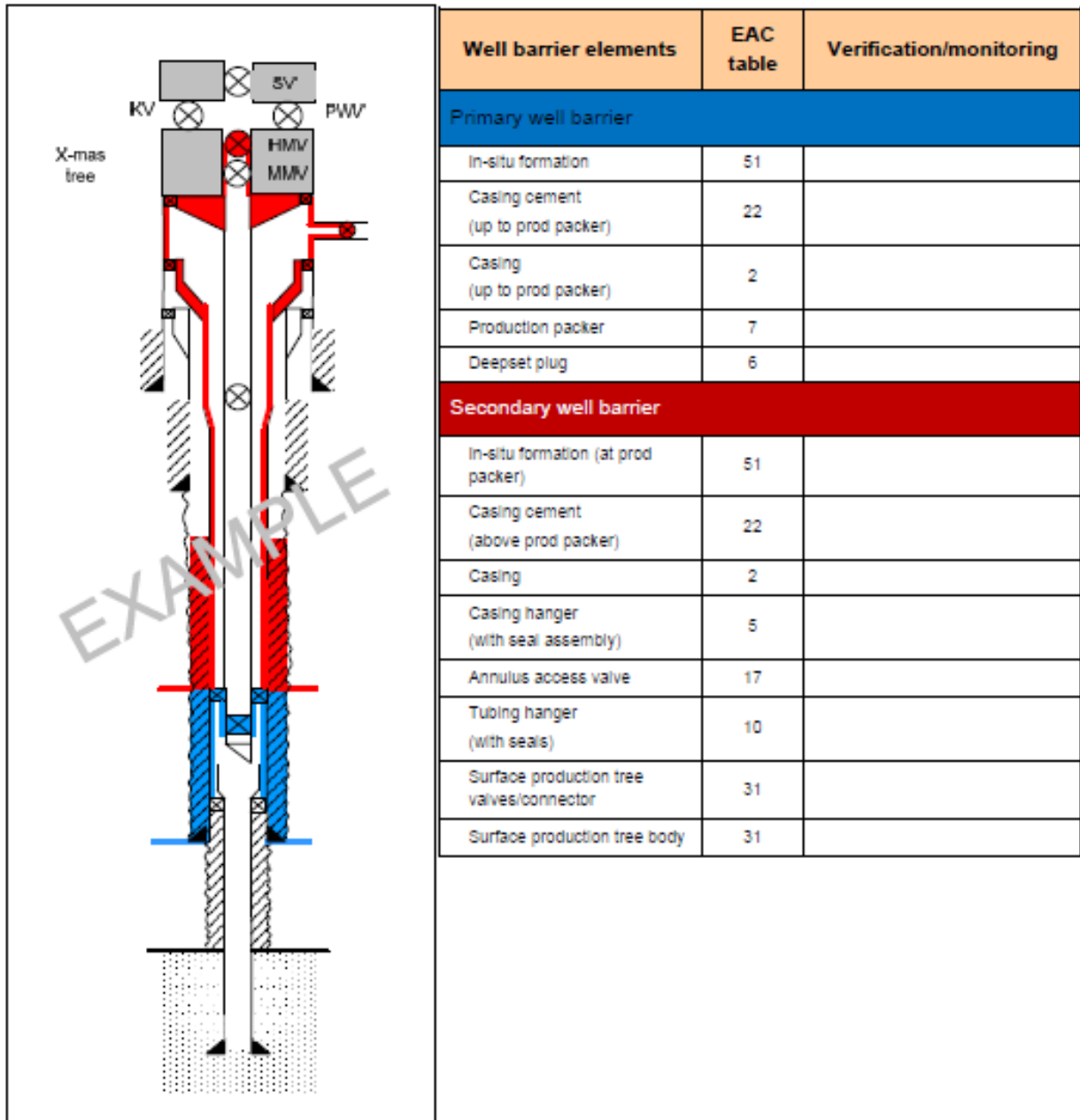


Figure 13: Example WBS with EAC referral [6]

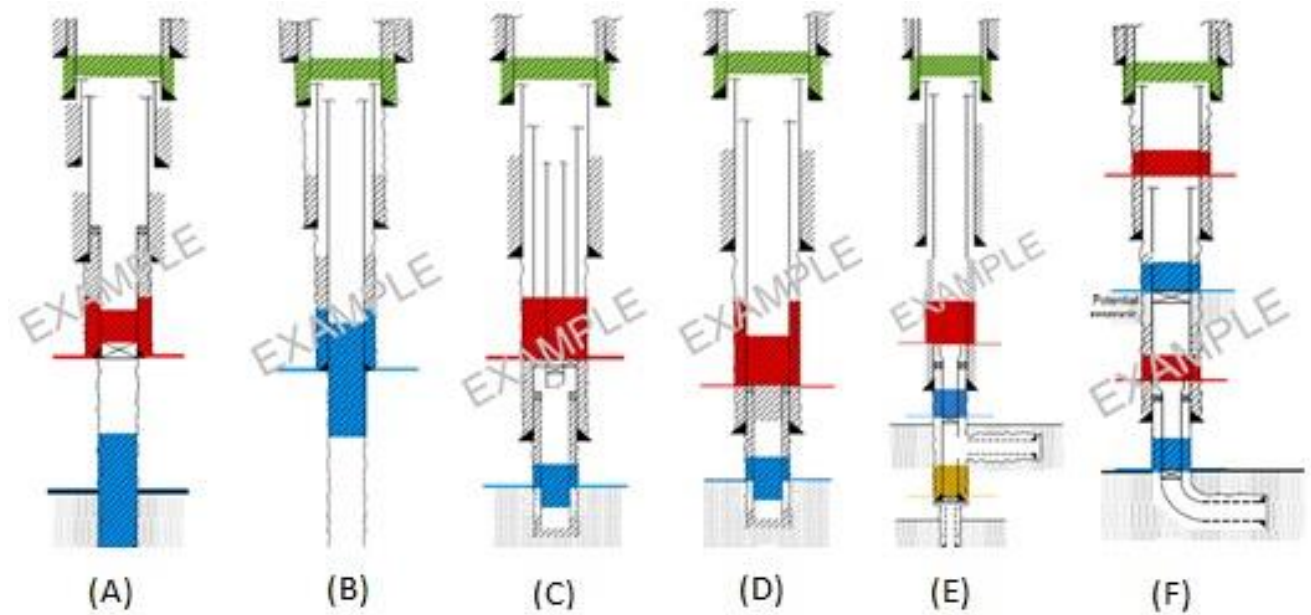


Figure 14: Example of WBSs [6]

Explanations to Figure 14:

- (A) Illustrates a WBS for the scenario of an open hole P&A
- (B) Illustrates the situation for an open hole P&A with casing used when there is no source of inflow.
- (C) Illustrates a perforated well with tubing left in hole.
- (D) Illustrates a perforated well with tubing removed.
- (E) Illustrates a multi bore well with slotted liners or sand screens. The orange plug illustrates a cross flow barrier.
- (F) Illustrates a well with slotted liner in multiple reservoirs

4.1.9 Examples of different options for setting the plug

When abandoning a well there are several options for where in the wellbore to set the plugs. Some possibilities are that one can set an open hole cement plug across the reservoir, back-to-back cement plugs from the reservoir or combine cement plug with a mechanical plug as foundation above the reservoir. These different options are illustrated through 1-4 in Figure 15 and explained below.

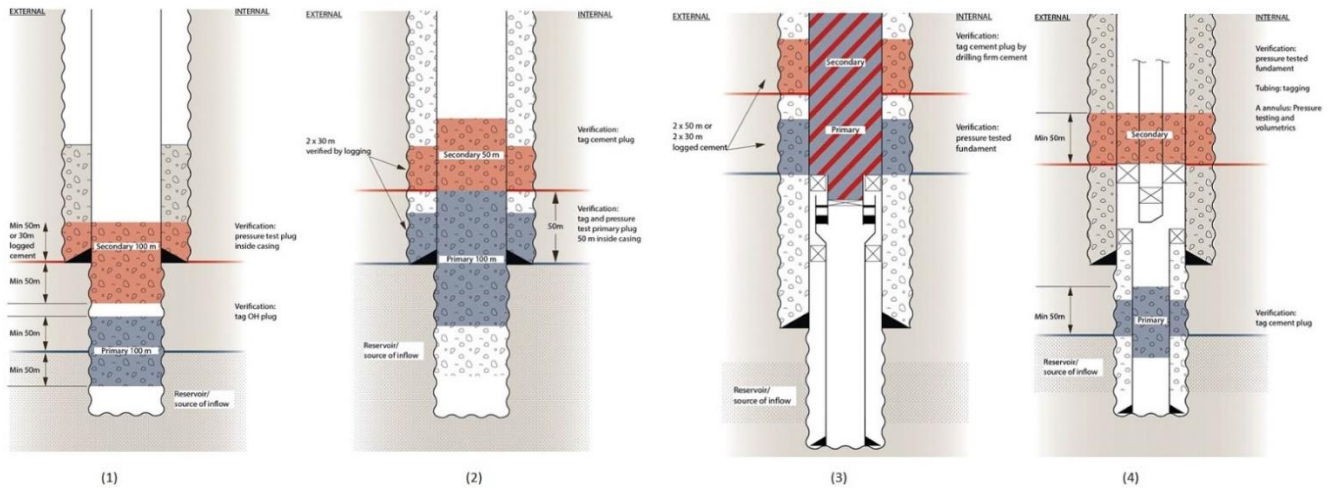


Figure 15: Examples of different options for setting plugs for permanent abandonment [6]

- (1) – An open hole cement plug across/above the reservoir is set to abandon the last open hole section of a wellbore. An additional cement plug is set from the open hole into the casing. Requirement is to have sufficient formation integrity at the base of both well barriers.
- (2) – Two back-to-back cement plugs from the reservoir (or as close as possible to the reservoir) is set to abandon the last open hole section of a wellbore or a perforated casing/liner. This is an option provided the cement in the annulus is verified. The internal cement plug length covers the logged interval in the annulus.
- (3) – A mechanical plug serves as foundation for a single cement plug to abandon a wellbore. The internal cement plug length covers the logged interval in the annulus.
- (4) – The last section of a perforated casing/liner or wellbore is abandoned by setting a primary cement plug above the reservoir (or as close to the reservoir as possible) and the secondary cement plug is set within the tubing and tubing annulus.

4.1.10 Methods to establish cement plug

The standard illustrates roadmaps to establish a permanent well barrier for wells with poor casing cement or no access to the last open hole section in order to establish contact between plug and formation. The alternatives shown in NORSOK D-010 is section milling to set a cement plug, squeeze cement perforations and circulation of the casing annulus to create a clean, water-wet interval for bonding followed by placing a continuous plug from fundament to 50m above perforation.

4.1.11 Other topics

Other topics that are covered in the standard are risks and removal of vertical XT (VXT) and horizontal XT (HXT). Regarding risks NORSOK D-010 states that design and operational risks shall be assessed and it lists the following typical risk which could be present;

- a) Pressure and formation integrity uncertainties;
- b) time effects:
 - 1) long term development of reservoir pressure;
 - 2) deterioration of materials used;
 - 3) sagging of weight materials in well fluids.
- c) scale in production tubing;
- d) H₂S or CO₂;
- e) release of trapped pressure;
- f) unknown status of equipment or materials;
- g) environmental issues.

4.2 Oil and Gas UK – Guidelines for the abandonment of wells

The current Guideline for the Abandonment of Wells was published in July 2015 and is the 5th issue of the guidelines. The guidelines have been established to provide support to well-operators with regards to abandoning a well by outlining considerations that needs to be taken. The guidelines are a set of minimum criteria to ensure full and satisfactory isolation of the fluids existing within the wellbore and surrounding formations [34].

The guidelines are made in compliance with *the Offshore Installations and Wells Regulations 1996*, referred to as DCR, which amongst other topics cover well integrity, design for abandonment and materials. The DCR lay down the minimum standard that should be achieved and requires well-operators to prevent that fluids escape from the well on a permanent basis. There should be allowance for deterioration of some well components over time, and the possible recovery of hydrocarbon-bearing formations to virgin pressure. Further, the regulations require that the risk should be reduced to as low as reasonably practicable (ALARP) as a general practice. The guidelines only take UK legislation into consideration.

“The intent of the guidelines is to provide the framework for the decision-making process that should accompany any well abandonment activity. Some of the requirements are prescriptive, in that barriers must be provided. However, the requirement for each barrier should be identified, and conversely, the case for omitting a barrier must be justified, on a well-by-well basis.” [34].

The guidelines apply to all exploration, appraisal and development wells that are being abandoned or plugged. Each well should be evaluated on an individual basis as all wells are unique.

In addition to the Guidelines for the Abandonment of Wells, Oil and Gas UK have made guidelines on the qualification of materials to be used and for cost estimation for abandonment of wells. These two additional guidelines will be presented in brief in this thesis. For simplicity, the term “*UK guideline*” or “*main guideline*” will in this chapter refer to the *Guidelines for the Abandonment of Wells*, the term “*material guideline*” will be used for *Guidelines on the Qualification of Materials for the Abandonment of Wells*, and the term “*cost guideline*” refers to *Guidelines on Well Abandonment Cost Estimation*.

4.2.1 Definitions

The following definitions are extracted from the glossary in the guidelines [34]:

Fluid – Refers to both liquids and gases

Good Cement – cement that has been verified as to position, quantity and quality as stated in Section 7 of the guidelines.

Permanent abandonment – The permanent isolation from surface and from lower pressured zones, of penetrated zones with flow potential in any well that will not be re-entered

Permanent barrier – A verified barrier that will maintain a permanent seal. A permanent barrier must extend across the full cross section of the well and include all annuli. When considering isolation from surface, the first barrier above the point of potential influx is referred to as the *primary barrier*; the next barrier above the potential influx is referred to as the *secondary barrier*.

Plugged – Mechanical plugs provide isolations between reservoir and wellbore

Shut in – tree, wellhead and/or downhole valves are shut

Suspension – Relates to suspension of an activity or operation on a well. It is the construction or operational activity that is suspended, not the well.

Well – A well is a single wellbore or aggregation of wellbores from a single well origin. It includes original wellbore, any side-track from it and any hole section as defined by Regulation 2, DCR.

Well Origin – The location where the drill bit penetrates the earth to establish a well

Wellbore status – the guidelines separates between three wellbore statuses called phases;

- Abandoned Phase 1 – The reservoir has been permanently isolated
- Abandoned Phase 2 – All intermediate zones with flow potential have been permanently isolated
- Abandoned Phase 3 – Well is abandoned after removing the wellhead and conductor

Zone with flow potential: sequence of rock that is capable of flow of fluids

4.2.2 Material requirements for permanent barriers

As mentioned, Oil and Gas UK has published a separate guideline on the qualification of materials to be used in P&A. In this sub-section highlights of that document, in addition to the material section in the main guideline will be presented.

According to the UK guideline the characteristics of the barrier material should be as follows [34]:

- Very low permeability, to prevent flow of fluids through the bulk material
- Provide an interface seal, to prevent flow of fluids around the barrier
- The barrier material must remain at the intended position and depth in the well
- Long-term integrity, long-lasting isolation characteristics of the material, not deteriorate over time; consider risks of cracks and de-bonding over time

- Be resistant to downhole fluids, such as CO₂, H₂S, hydrocarbons, brine, at foreseeable pressures and temperatures.
- The mechanical properties should be suitable to handle loads at foreseeable temperatures and pressures.

When placing the barrier material, it is extremely important to consider the downhole placement technique and a support for the cement plug (e.g. bridge plug or viscous pill) is recommended to prevent slumping of the slurry. In cases where the existing material in the well is planned to be part of the permanent barrier, it should be checked with respect to suitability and condition, e.g. scale, corrosion, mud solids. There should be a way to verify the barrier once it been set.

With respect to the barrier material, cement is the prime material chosen for permanent barriers. This does however not exclude any other material from being used provide it in principle comply with the requirements mentioned above. In the separate guideline on the qualification of material, several other material types are presented with relevant properties, test requirements, acceptance criteria etc.

4.2.2.1 Guidelines on qualification of Materials for the Abandonment of Wells

The current material guideline is the 2nd issue and was updated and published together with the UK guideline in 2015. The material guideline has been issued to give a reference to well-operators, manufacturers and regulators on material qualification within P&A and it compiles the current industry expertise.

Cement is the primary material used in the industry today mainly due to that it is considered to have similar properties as the rock it is replacing. However, cement does have its limitations and alternative materials have been developed which might have better suitability and advantages for use in permanent well barriers. The problem with the new materials is that they have been applied very little or not at all in abandonment mainly due to uncertainty with respect to the eternal perspective they should have. Following this issue, the main objective of the material guideline is to stimulate the industry to consider a wider range of materials by covering the steps that should be taken in a qualification process to ensure the long-term integrity of the materials. With respect to material requirements the guideline states that there are very few differences with NORSOK D-010.

The document contains 103 pages and give extensive guidelines on the following topics [35]:

1. General considerations for qualification of new technologies
2. Functional requirements of permanent barriers
3. Operating condition

4. Potential failure modes and root causes
5. Material types
6. Approach to defining acceptance criteria for mass transport properties
7. Experimental work plan – both general and for specific material types
8. Appendices containing topics such as chemical environment, radiation, pressure estimation, flow rate calculations, typical caprock properties, diffusion calculation, relevant standards etc.

The material guideline will not be presented in detail in this thesis. However, it is worth noting that the following material types are listed as potentially suitable barrier materials; cement/ceramics, grouts, thermosetting polymers and composites, thermoplastic polymers and composites, formation gels, glass and metals.

4.2.3 Zones with flow potential

The main objective of abandonment is to isolate zones within the rock formations which have flow potential. Hence, it is important to have a thorough investigation of the flow potential in individual formations penetrated by the well when designing the well barriers [34]. Rock with low or no permeability (like chalk and shales) may also have flow potential if for instance it is fractured, and should in such cases also be isolated.

When assessing flow potential, it should account for future scenarios such as recharging of reservoir, re-development for hydrocarbon extraction, use for geothermal projects, or storage of energy or CO₂. The assessment is based on drilling records (gains/losses/gas levels), log evaluation and well annuli pressures. Flow potential may only be revealed once the abandonment operation is started and therefore sufficient pressure control is a precaution required in operations.

For formations of similar fluids and/or pressures inter-zonal isolation may not be required and a group of formations can be isolated by a common barrier, or dual barrier if required. When evaluating measures to mitigate the possible consequences of flow potential the ALARP approach should be taken.

The evaluation of flow potential will require an assessment of the risk of harm to both environment and people and these considerations should include cross-flow between formations and outflow at surface. Typically, such an assessment will consider formation fluids, pressure, formation strength, sustainability and rates of potential flow, environmental impact, feasibility of remedial actions and response time [34].

4.2.4 Permanent barriers

4.2.4.1 Number of barriers

The guidelines states that all penetrated zones which has identified flow potential and requires isolation should be separated from each other and seabed/surface by minimum one permanent barrier or two when appropriate.

Two barriers are necessary if the zone in question are hydrocarbon-bearing or over-pressured and water-bearing where one is the primary and the other the secondary barrier. Provided it accomplish the same level of effectiveness and reliability two barriers may be combined into a single large barrier. Verification should comply with section 4.2.5 and decisions on number of barriers and whether to combine them or not should be fully risk assessed and documented.

Figure 16 illustrates a schematic of a permanent barrier, barrier elements and recommended practises including the barrier envelope, in red dashed lines, to restore the caprock.

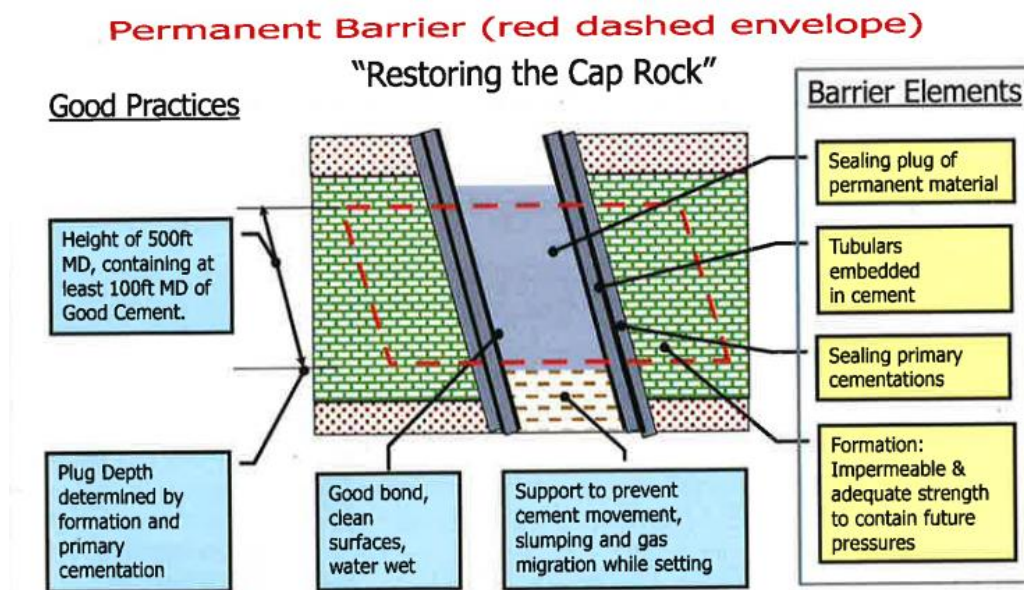


Figure 16: Schematic of permanent barrier [34]

4.2.4.2 Position requirement

The UK guideline states that the primary barrier should be set above the zone with flow potential across a suitable caprock which is impermeable, laterally continuous and with adequate strength and thickness to contain the maximum pressure expected. If the barrier is set inside a liner or casing it should have overlap with the annular cement and the setting depth is determined by the formation fracture pressure at the base of the barrier, if the base is considerably above the point of inflow.

In situation requiring a secondary barrier, this should also be set in suitable caprock and act as a backup to the primary barrier. The same consideration applies to the secondary barrier as the primary, meaning that the formation fracture pressure at the base of the barriers should be higher than the maximum expected pressure from the zone being isolated. As illustrated in Figure 17, a barrier can act as a secondary barrier to one zone with flow potential while it is the primary barrier to another zone [34].

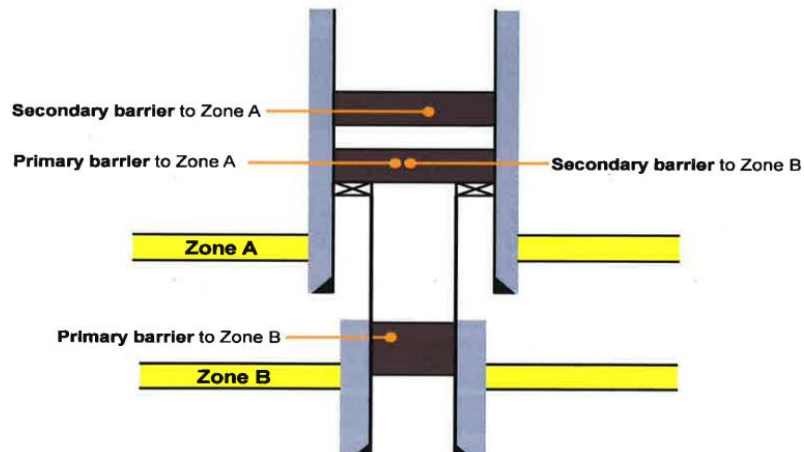


Figure 17: General requirements for well abandonment [34]

In Figure 18 a different scenario is illustrated where no barriers are shared between formations. This is determined by the geological setting and in the illustration the main reservoir and both sandstone formations are considered hydrocarbon-bearing and/or over-pressured. This scenario shows that the caprock L does not have sufficient strength to hold the maximum expected pressure from the main reservoir and caprock K cannot hold the pressure from sandstone B, and hence the barriers cannot be shared. To prevent slumping of the cement slurry down the well or gas migrating upwards as the cement is setting, the barriers are positioned on a packer or bridge plug to provide firm support.

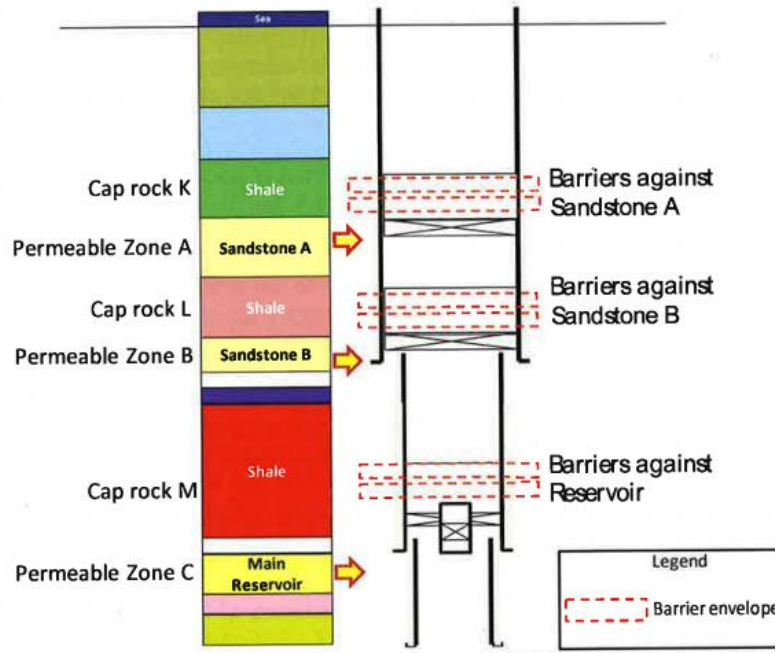


Figure 18: Illustration of geological setting for permanent barriers [34]

4.2.4.3 Length requirements

The UK guideline states that good industry practise is to have at least 100ft (~30,5m) measured depth (MD) of good cement but in general, where it is possible, 500ft(~152,5m) MD are set. The primary barrier should contain good cement over an interval of at least 100ft MD above the highest point of potential inflow.

If distinct zones with flow potential are less than 100ft MD apart, then the maximum practical interval of cement should be placed between them.

For wells where the casing is part of the barrier, there should be at least 100ft MD of cumulative good cement on both the inside and outside of the casing which must be adjacent to each other.

In situations where two barriers are replaced by a combined one the requirements are similar to the ones mentioned above, with the difference that the length is now an interval of at least 200ft (~62m) MD good cement to act as permanent barrier. An 800ft (~244m) MD interval is generally set. The two different situations are illustrated in Figure 19.

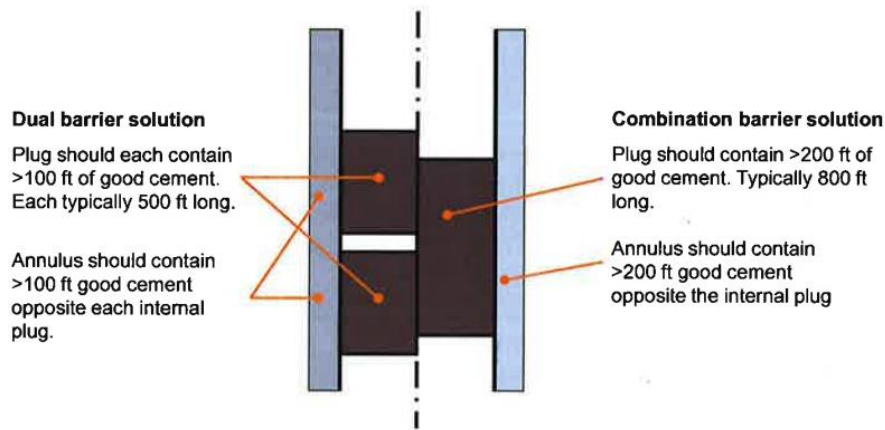


Figure 19: Length requirements for permanent barriers [34]

4.2.4.4 Open hole requirements

The guideline describes four different scenarios for open hole P&A where both dual barrier solution and combination barrier solution is shown. The requirements outlined in previous sections apply for open hole abandonment but there exist different ways of implementing them depending on the conditions found downhole. There is a requirement to set a permanent barrier in cased hole or extending at least 100ft of good cement into cased hole and this barrier shall fully isolate the open hole and allow for a pressure test. If the permanent barrier is not set in a cased hole, a risk assessment should be performed.

The first scenario outlined in the guideline is when the permanent barriers are fully set in the cased hole as seen in Figure 20. This is allowed due to the potential internal pressure not exceeding the casing shoe fracture pressure.

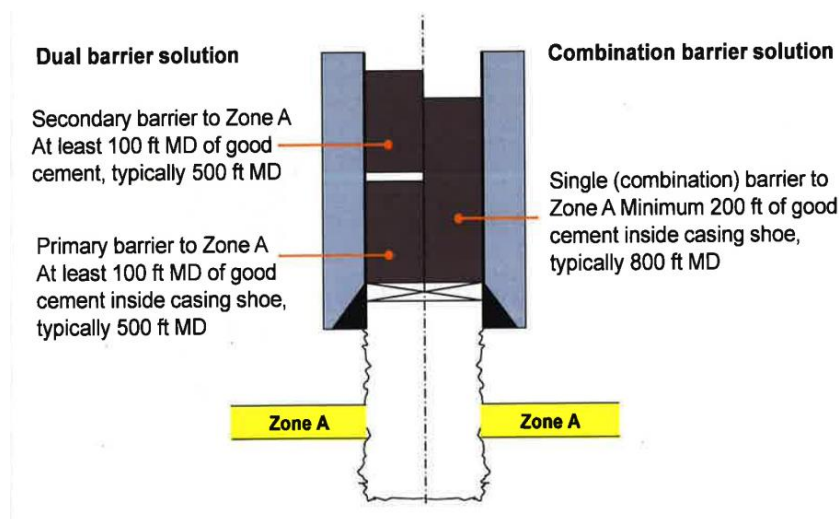


Figure 20: Open hole P&A where internal pressure is less than casing shoe fracture pressure [34]

The second scenario illustrated in Figure 21 is an example of a well with two flow potential zones in different pressure regimes which need isolation from each other but where the potential pressure from zone A does not exceed the casing shoe fracture pressure. Generally, each zone should have two permanent barriers each but as the pressure from zone A is lower than the casing shoe fracture pressure it is sufficient to have only one permanent barrier between the two zones.

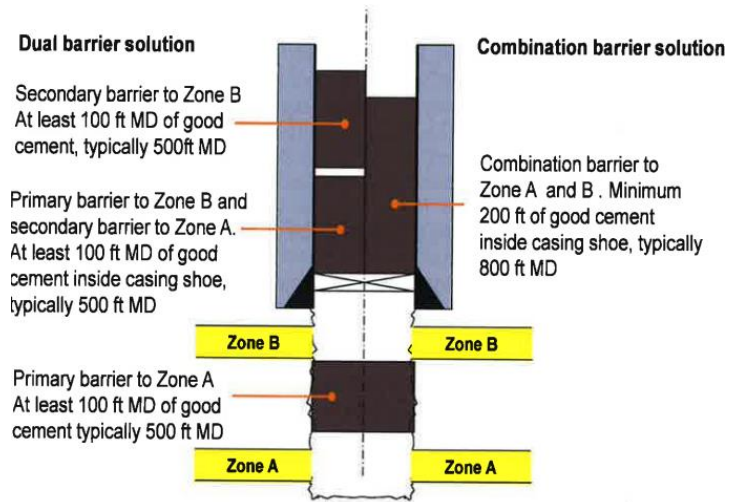


Figure 21: Example of open hole barriers where two zones need isolation from each other but does not exceed the casing shoe fracture pressure [34]

The third scenario, Figure 22, illustrates open hole permanent barriers where the potential internal pressure exceeds the casing shoe fracture pressure. In this case, two permanent barriers are required within the open hole (with the potential internal pressure not exceeding the fracture pressure at the base of the barriers) in addition to a barrier set somewhere within the casing to fully seal the open hole. The topmost barrier can be compared to the surface barrier found in NORSOK D-010

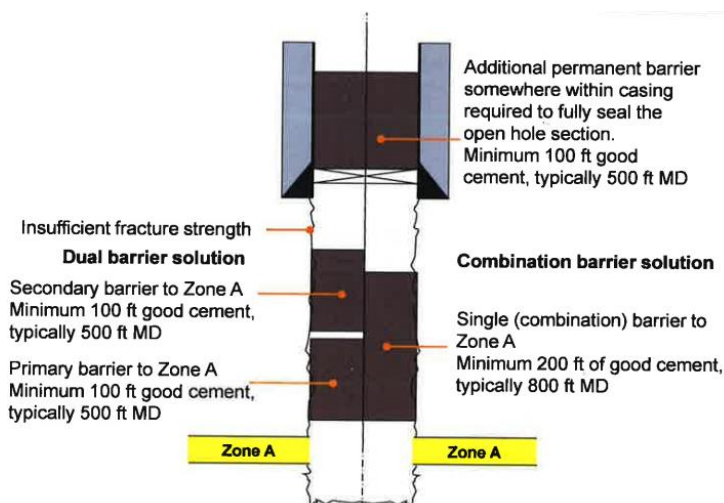


Figure 22: Example of open hole barrier where potential internal pressure exceeds casing shoe fracture pressure [34, 36]

The fourth and final scenario outlined in the UK guideline is the case when a side-track to the original wellbore exists with abandoned open hole section, as seen in Figure 23. In this case an open hole has been side-tracked and cased across the kick-off point without achieving a top of cement into previous shoe. Then a cased hole barrier should be set above the side-track point. If a cased hole barrier to the side-track is not installed, a risk assessment should be done for the final abandonment of the well.

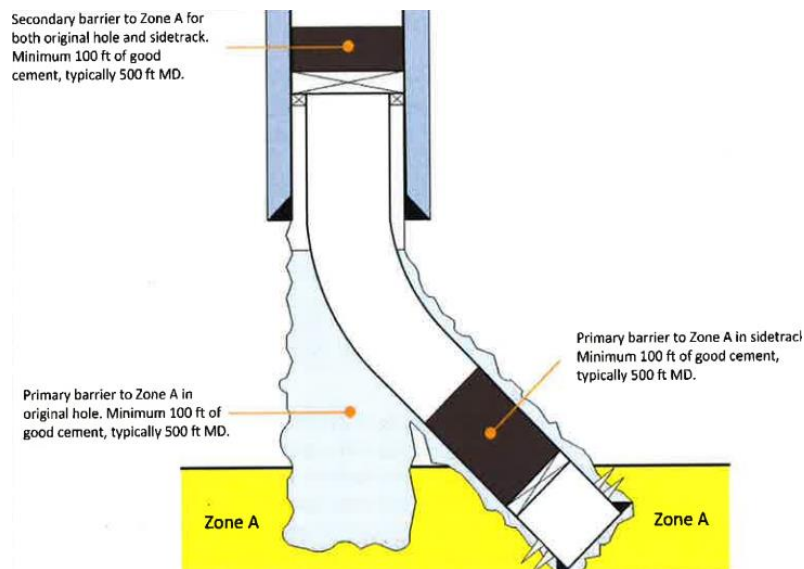


Figure 23: Example of side-tracked well with open hole section [34]

4.2.4.5 Cased hole requirements

According to the UK guideline, cemented casing cannot act as a permanent barrier in the lateral direction due to potential poor cement jobs that results in leakages through the cement sheet as illustrated in Figure 24. However, cement casing *is* considered satisfactory as barrier in the vertical direction if there is sufficient confidence in the quantity and quality of the annulus cement. An interval of 100ft MD of good cement in the annulus is considered sufficient for it to act as a permanent barrier.

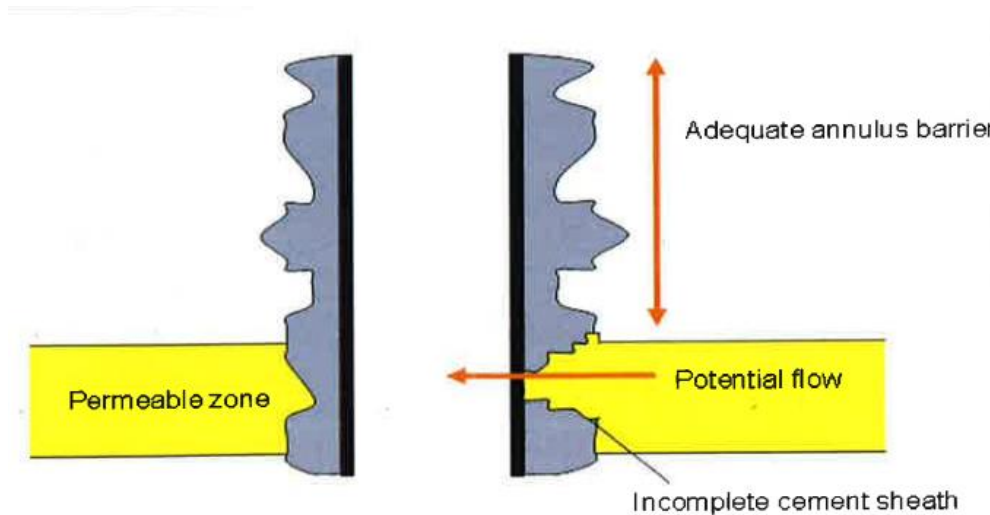


Figure 24: Casing alone is not accepted as lateral permanent barrier [34]

TOC in the annulus can be verified by different logging tools or by documentation of the original cement job (i.e. measured volumes, differential pressure, etc.). If the original documentation is used for verification, it requires a longer cement column in annulus to account for uncertainty. In this case, the cement column in annulus should extend 1000 ft. (~305m) above the base of the primary permanent barrier. This length may be reduced or increased depending on the confidence in TOC for each well.

If the records show any problems during the initial cement job or in the wells life cycle, it may indicate lacking annulus barrier. In this case, remedial actions may be necessary to ensure the quality of the cement behind the casing. Such actions may be retrieving the casing, placing cement in annulus by perforating or circulating, or section milling.

An overview over a cased hole abandonment is illustrated in Figure 25. The general requirement is that formations should be internally separated by one permanent barrier. However, if cross-flow is deemed acceptable (e.g. formations within same pressure regime) it is not necessary to install barriers between the different zones as seen in the figure. In the figure, 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 (100ft column).

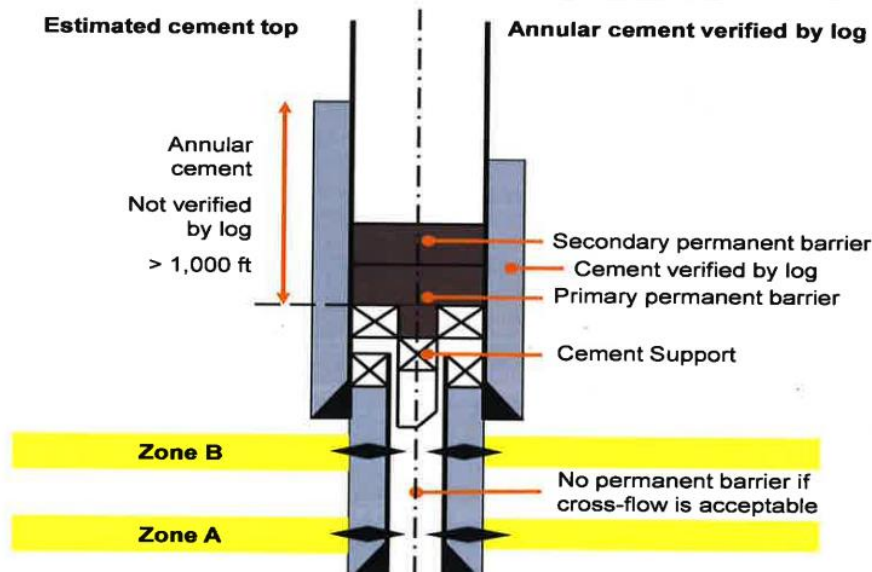


Figure 25: Example of cased hole abandonment [34]

4.2.5 Verification of a permanent barrier

Verification should be done to ensure that all permanent barriers is positioned at the required depth and have the required sealing ability. Each well and job design will have different acceptance criteria and requirements and should be treated as such. The UK guideline gives instructions for verification of wellbore barrier and annular barrier, and refers to the Well Cycle Integrity Guidelines for requirements regarding pressure and inflow testing.

Wellbore barrier: the wellbore barrier should be verified by several individual measures. There should be documentation and records for the actual cement operations which includes parameters such as volumes pumped, water-wetting pills and returns during cementing. The depth of the cement plug should be verified by tagging or measurements.

Further, there should be a pre-job testing with representative component samples cured at expected downhole pressure and temperatures to confirm the strength development of the cement slurry. If using surface samples caution should be taken to rely on them as they will not be a replicate of the downhole pressures and temperatures. Verification method for the cement plug depends on whether it is entirely in open-hole or in cased hole.

If the cement plug is in *open hole* it should be verified by a weight test which typically is 10-15 klbs. (~ 4,5 to 7 ton) if deployed on drill-pipe. If deployed by coiled tubing, wireline or stinger the weight will be limited by the tools and geometry.

In *cased hole*, barriers should be verified by a documented pressure or inflow test. For pressure testing, it should exert a minimum of 500psi above the injection pressure below the barrier.

Inflow test should be run to at least the maximum differential pressure expected for the barrier.

If a tagged and pressure tested mechanical plug or previous cement plug is used as foundation in cased hole, pressure testing may not be meaningful and tagging of the barrier may not be necessary if the cement job goes as planned. This is due to that it is impossible to determine if it is the mechanical plug/previous cement or the installed barrier that is sealing. However, a risk assessment should be conducted to document and evaluate the rationale behind deciding not to tag.

Annular barrier: Logs (e.g. cement bond, temperature, sonic) or estimation based on records from the cement job (e.g. volumes pumped, returns during cementing, differential pressure) should be used to verify the top of cement for the annular barrier.

With respect to the *sealing capability* of the annular cement, this should be assessed and verified with support from the following:

- Logs
- Absence of sustained casing pressure during the life cycle of the well
- Leak-off test performed when the casing shoe was drilled out
- Absence of anomalies during the original cement job
- Consider issues such as centralization, washouts, lead/tail slurry, annulus pressures, field experience and excess.
- Pressure test

The UK guideline provides two tables which aims to help with the verification methods for cement and annular barrier. The tables cover both single and combination barrier and can be found in Appendix A and B.

4.2.6 Special considerations for abandonment

The UK guideline mentions several special considerations for P&A, being more thorough than NORSOK D-010 and these will be outlined in this section.

4.2.6.1 Well design

There exist clear regulations in the UK [36] which states that a well *shall* be designed and constructed so that as far as it is reasonable practicable it can be suspended or abandoned in a safe manner and there can be no unplanned escape of fluids from it or the reservoir beneath it after abandonment/suspension. In addition, the UK guideline states that the key to a simple abandonment is the initial well design and that well-operators must consider abandonment as part of the design and modification to account for future effects of the decisions.

4.2.6.2 Partial abandonment for side-tracking or for other reasons

The requirements for barrier explained in the previous sub-section applies to the original wellbore when side-tracking but the guideline allows for temporary abandonment if there is high confidence that permanent barrier can be set when final permanent abandonment of the entire well.

4.2.6.3 HPHT wells

The UK guidelines states that in addition to following the requirements outlined for standard wells, due to the increasing complexity and criticality of these types of wells there should be special emphasis on recharging to high pressure, caprock depletion, thin pressure transition zone, liner deformation, temperature cycling and subsidence etc.

4.2.6.4 Multilateral wells

The following considerations may be valid for multilateral wells:

- Future abandonment in the well design as it might be very difficult to regain access to the wellbore
- The lateral branches might have different pressure regimes
- Cementing off annuli above the laterals (as barriers might already be installed here)

4.2.6.5 Overburden competence due to reservoir compaction/subsidence

When selecting the position and properties of permanent barriers there should be a risk assessment conducted which assess the overburden formations and whether they are prone to formation compaction and/or subsidence of the seabed.

4.2.6.6 High angle and horizontal wells

P&A of horizontal and high angle wells are in principle the same as standard wells. A high angle well is defined as a well having an angle higher than 70°. The difference is that it is more difficult to

achieve satisfactory isolation and the means of ensuring isolation differs. The main problem is situations where there is more than one zone with potential flow. To account for this situation, the completion design should consider future abandonment and in general the abandonment requirements should be established at the planning/completion design phase of the well. The zones may then be isolated in accordance with the guidelines with minimum effort.

If there is only one zone with flow potential, a mechanical device such as a bridge plug is set just above the start of the reservoir with a cement plug on to as a first permanent barrier. It must extend to the full cross-section. This is illustrated in Figure 26 below.

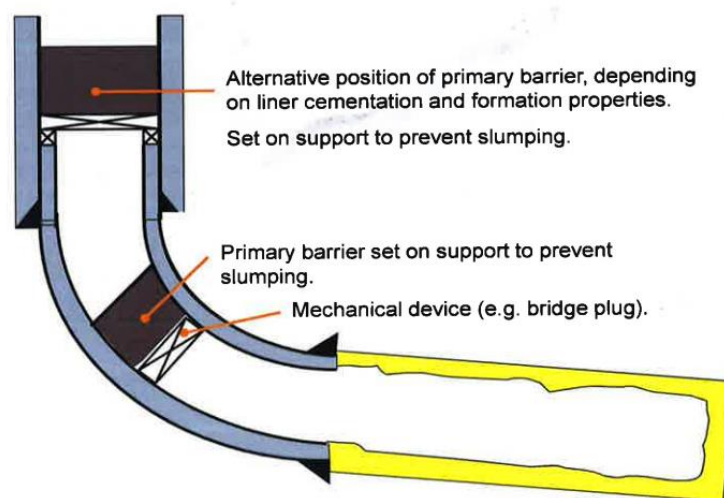


Figure 26: Abandonment of high angle well [34]

4.2.6.7 Sealing formations

Over time, some formations are known to move due to stress differences. These formations can be accepted as replacement for good cement in annulus if it can be demonstrated that the seal against the casing is impermeable and have sufficient strength to withstand the anticipated future pressures. The qualification for using formation as seal in a well should be documented and requires:

1. Documentation that the formation has sufficient fracture strength to hold against the expected future pressures.
2. Verify that the seal has an interval of at least 100ft per barrier where the bond log response must be equivalent to good cement or better. This must be verified by two independent logging tools and interpreted by a qualified log specialist.
3. Validation that at the anticipated future pressures the bond log response can be interpreted as not leaking. A means of achieving this is to run a pressure test between 100ft spaced perforations.

4.2.6.8 Liner laps

According to the guideline a liner lap should not be part of a permanent barrier unless at least 100ft of good cement has been verified across it, as it is for all barriers. If the cement quality in the liner lap cannot be assured, the barrier should be set above or below it. Figure 27 illustrates liner lap cementation.

The reason is that common practice makes it impossible to distinguish whether it is the packer or the liner lap holding the pressure as the packer is set straight after cementation and they are tested together. This is sufficient for the production life but it not considered adequate for permanent abandonment barriers.

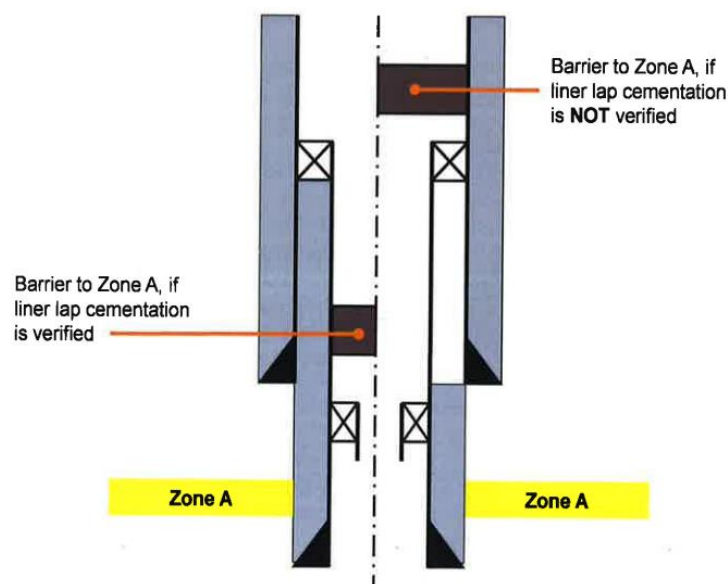


Figure 27: Liner lap cementation [34]

4.2.6.9 Trough-tubing abandonments

Through tubing abandonments is when well completions are left in the hole and permanent barriers are to be installed through and around the tubular. In these situations, reliable methods and procedures for barrier placement and verification should be established. Allowances should be made for the possibility of cement slumping or fingering in the annuli to ensure full cross-sectional barrier. There is no accurate method available for determining TOC in both tubing and annulus, and thus a method of tagging combined with quality control through e.g. measurements of cement job and pressure testing of both annulus and tubing is recommended. Figure 28 illustrates an example of through-tubing abandonment where a combination barrier is used. Barriers in the A-annulus is set by punched tubing (induced holes in tubing followed with

cement squeezing). 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.

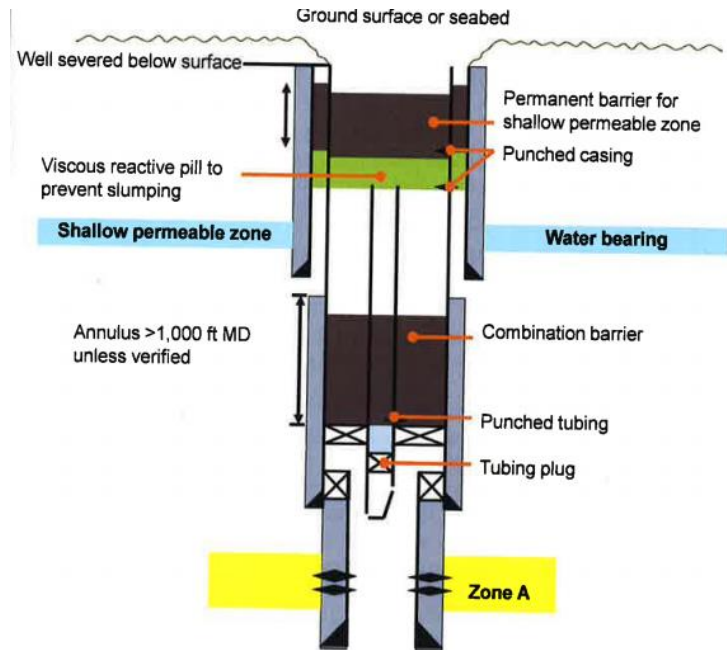


Figure 28: Through-tubing abandonment [34]

4.2.6.10 Removal of subsea equipment

When permanently abandoning a well there should be no redundant subsea equipment left which can present hazards to other users of the sea. Retrieval of all casing strings to a minimum of 10ft below seabed is seen as good practise but must be reviewed on individual well basis accounting for local conditions such as sand waves and scouring. Where practicable all subsea equipment and debris should be removed and a seabed clearance certificate should be issued. If there are any large structures permanently left at seabed in vicinity of the well (e.g. concrete) no casing strings should extend above the remaining structure.

4.2.6.11 Additional special requirements

In addition to the requirements mentioned separately above, the UK guideline provides some advice or reference to the following issues:

- *Irretrievable radioactive sources;* advice should be sought from the Environmental Agency or Scottish Environment Protection Agency (SEPA).
- *Casing cuts;* trapped gas or sources of pressure may be present behind the casing and precaution should be taken before cutting the casings. Also, as casings usually are in tension, cutting it will cause the lower part to drop which may result in trapped gas to be released.

- *Removal of downhole equipment*; provided the required isolations in the guidelines are achieved it is not required to remove downhole equipment.
- *Control lines, ESP, gauge cables*; these components should not be part of the permanent barriers as they may be potential leak paths. Hence, they should be removed (at least for the intervals where the barriers are set)
- *Wells containing H₂S*; the barriers should be chosen and designed to withstand the corrosive environment
- *Wells containing CO₂*; applies to wells naturally containing CO₂. The barriers should be chosen to withstand the potential effects the gas can have on cement (degradation in presence of water), steel components (corrosion) and subsurface formations (thermal fracturing).
- *Wells containing magnesium salts*; magnesium salts are a potential risk as it may degrade the cement by lowering its mechanical strength and increase its permeability.
- *Gas wells and high gas oil ratio (GOR) wells*; these types of wells have an additional concern in potential gas migration through barriers and it is recommended that barrier material and deployment technique is carefully chosen.
- *Annular fluids*; Fluids that cannot be legally discharged and are located in the uppermost section of the well should be removed or contained before removal of wellhead as this will expose them to the environment.
- *Shallow water-bearing zones*; in some cases it will be necessary to isolate shallow water-bearing zones in a well but this depends on local conditions and needs to be evaluated on a well-by-well basis.
- *Hydrocarbons of biogenic nature*; this is hydrocarbons which are found anywhere and originates from shallow formations. The presence of these substances does not necessarily indicate a barrier failure. Composition analysis can be run to identify the biogenic hydrocarbons and evaluate whether there is any indication of barrier failure or not.
- *Trawlability*; as partially abandoned wells (phase 1 and 2) normally does not have exclusion zones (500m) it is important to notify relevant agency of the presence of a wellhead. Wellhead protection should be considered to provide protection for both wellhead and trawlers depending on local conditions.

4.2.7 Phases of well abandonment

The UK guideline separates the abandonment of wells into 3 different phases which are distinguished by the operations performed and installation of barriers [34].

Abandoned Phase 1: The reservoir has been permanently isolated which requires that barrier material is positioned to permanently isolate all reservoir zones used for production or injection from the wellbore. The tubing may be left in place, partially or fully retrieved.

Abandoned Phase 2: All intermediate zones with flow potential have been permanently isolated. This phase is completed when there is no need for further permanent barriers meaning that tubing may need to be pulled if not done already in addition to isolating liners, milling (if necessary), retrieve casing and setting a permanent barrier (cement or other material).

Abandoned Phase 3: After removal of wellhead and conductor the well is considered to be fully abandoned and it is never to be re-entered or used again. The well origin at surface is removed and so is any subsea equipment.

4.2.7.1 *Well re-entry considerations*

“Phase 1 and phase 2 abandonment must be carried out so that the well can be re-entered safely, and then secured using pressure control equipment without compromising the barriers in place.” [34]. In order to make re-entry of the well as smooth as possible, consideration should be given to ensure sufficient depth of the shallowest barrier.

4.2.7.2 *Inspection scheme for phase 1 and phase 2 abandoned wells*

Regulation 18 in DCR [36] requires all well-operators to perform well examination on all wells. This applies throughout a wells life cycle and thus operators should consider physical inspection schemes for phase 1 and 2 of abandonment.

4.2.8 Appendices

The UK guideline contain 7 appendices, A-G, which provides additional information on topics mentioned within the document. The appendices provide information regarding the following:

Appendix A – Statutory notifications, approvals and record keeping: states which regulations apply for the different issues such as HSE, permits that may be required and Oil and Gas authority requirements.

Appendix B – Basic well data required for well abandonment: this include parameters such as well configurations, the stratigraphic sequence of each wellbore with information about reservoir fluids and pressures, logs etc from primary cementing job, estimated future formation fracture gradient and specific well conditions like scale, collapse casing and so on. These are the same as for NORSOK D-010.

Appendix C – Barrier integrity – potential issues and mitigations: this appendix provides examples of potential issues and possible mitigating measures that well-operators may consider when performing a risk assessment. The list (table) should be used in combination with good engineering judgement as it cannot cover every possible scenario that may arise.

Appendix D – P&A code: the guideline includes a P&A code which is used to categorize the work scope of plug and abandonment operations. It is valid for any well and all work phases and is used for high level cost estimation and benchmarking. More on this P&A code is outlined in subsection 0 on the cost estimation guideline.

Appendix E – Irretrievable radioactive sources – SEPA: Gives instruction on how to deal with radiation sources located within the well and which agencies that should be notified.

Appendix F – References and further reading

Appendix G – Background to the guidelines

4.2.9 Guidelines on Well Abandonment Cost Estimation

In addition to the guidelines for the abandonment of wells and material qualification, Oil and Gas UK has also issued a guideline for the cost estimation of well abandonment [37]. This is a document of 41 pages which covers cost estimation techniques in different scenarios for both well and entire fields and a classification system for wells (P&A code). The current document is the 2nd issue and was published in 2015. The aim of the guideline is to give specific guidance on how to estimate well abandonment cost as a subset to the overall estimates in the Decommissioning guidelines. The guideline is fairly extensive and therefore this thesis will be limited to presenting the highlights of the document.

The objective of the guideline is to outline best practise based on industry experience and aid UK operators of both offshore and onshore wells to generate good estimates by providing the following [37]:

- A template that operators can use to prepare their well abandonment cost estimates.
- A checklist of activities in order that an estimate can built on which is both consistent and complete.
- A methodology which requires that duration of activity and market rates are clearly understood and stated in the cost estimate.

- Recognition that more detailed estimates will be required as Cessation of Production (COP) is getting closer.
- Aiding in creating a greater level of confidence when determining decommissioning costs for asset acquisition or divestment.
- Provide a basis for comparing estimates from different sources and capture the operators experience.
- A framework for benchmarking

4.2.9.1 Regulatory Requirements

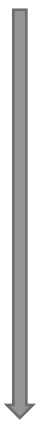
The cost guideline states that all activities shall be in accordance with the governing accounting protocols and standards in use in the country the company is registered. The offshore oil and gas sector is governed by the Petroleum Act 1998, which says that the obligation for decommissioning offshore infrastructure belongs to the owners of the site. As part of decommissioning responsibilities, companies have to include cost estimations in their normal accounting process where the accuracy of the estimates increases as the abandonment date approaches. The Petroleum Act 1998 states that an abandonment programme *shall* include a cost estimate of the activities and it shall either specify the time/time interval for the measures to be taken or make provision with regards to how the times are to be determined. Further, the regulations stated in UK Guidelines for abandonment of wells shall be followed.

4.2.9.2 Well abandonment cost estimation

For the cost estimation process the guideline emphasises that the guideline provides guidance on what should be considered when generating estimates through tables without including decisive numbers. It further states that uncertainties must be taken into account and all background documents and assumptions made must be recorded. It also put emphasis on the fact that the estimates will change over time and that they become more accurate as the end of production is approaching.

In relations to estimates accuracy the guideline acknowledges that the level of detail and accuracy will need to increase as the cessation of production (COP) 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. This is illustrated in Table 5 below which is copied from the cost estimation guideline [37].

Table 5: Level of accuracy required as COP approaches [37]

Increasing level of accuracy required 	Time to COP	Approach recommended to review wells	Proportion of wells required for review	Expected accuracy range
	> 10 years	Field-wide review of representative wells	10-25%	-30% to +50%
	5 to 10 years	Well-by-well review of sample to define concept design	All	-15% to +30%
	< 5 years	Detailed, full, well-by-well review. Timing of abandonment phases may need to be considered	All	-15% to +15%
	Imminent	Detailed well-by-well review of status, integrity, work units required + services cost	All	-5% to +15%
	For AFE	AFE estimates are out with the scope of the guidelines	All	

4.2.9.3 Classification System for well abandonment

As mentioned previously the UK guidelines provides a means of classifying wells based on location, abandonment complexity and abandonment phases. This is done to establish a common approach for all operators to limit the potential misunderstandings which may arise from different approaches being used. The method is called P&A coding and it consist of 2 letters followed by 3 digits. The two letters indicate the location of the well and the three digits represent the phase and complexity of each phase.

Location:

- PL – platform well
- SS – subsea well
- LA – land well

Phases: the phases are separated as outlined in 4.2.7.

Complexity: the complexity is divided into 5 types depending on the work required.

- *Type 0 – No work required.* A phase or phases of abandonment work may already have been completed
- *Type 1 – Simple rig-less abandonment.* Using wireline, pumping, crane, jacks. Subsea will use light well intervention vessel and be riser-less.
- *Type 2 – Complex rig-less abandonment.* Using CT, HWU, wireline, pumping, crane, jacks. Subsea will use heavy duty well intervention vessel with riser.

- *Type 3 – Simple rig-based abandonment.* Requiring retrieval of tubing and casing
- *Type 4 – complex rig-based abandonment.* May have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs.

Table 6 below illustrates how a matrix can be used to record the abandonment methodology for the three phases. The matrix can also be used for summarizing the number of wells within each type of abandonment if multiple wells are considered.

Table 6: Matrix for categorizing well abandonment [37]

Location			Abandonment complexity				
			Type 0	Type 1	Type 2	Type 3	Type 4
Phase	1	Reservoir abandonment					
	2	Intermediate abandonment					
	3	Wellhead conductor removal					

Table 7 shows an example where the P&A code would be PL 2/3/0. This would be the case for a platform well with reservoir abandonment using CT, then using a rig to for the second phase & no conductor removed (e.g. removed by HLV).

Table 7: Example of well categorization [37]

Platform well 17/19-A59			Abandonment complexity				
			Type 0	Type 1	Type 2	Type 3	Type 4
Phase	1	Reservoir abandonment			X		
	2	Intermediate abandonment				X	
	3	Wellhead conductor removal	X				

For evaluating the complexity of the abandonment the guideline refers to 3 tables, one for each phase, containing certain characteristics or conditions. Operators can use these as checklists and by following the sequence of the tables the complexity can be determined.

4.2.9.4 Well abandonment duration estimation

Determination of how long each phase of an abandonment operation will take is usually done by benchmarking against similar operations or by deterministic modelling. Each method is acceptable but assumptions made must be clearly stated. The estimate should include non-productive time, waiting on weather and extreme events. They should also establish the degree of skew within the dataset used and determine key factors such as P10, P50, P90 and mean within the distribution.

4.2.9.5 Well abandonment phase costs

The cost estimate of a phase is found by multiplying expected duration of a phase and the applicable spread-rate. The spread-cost can be determined top-down analysis of actual

abandonment data or by bottom-up analysis from the assumed utilisation and cost/day of the required equipment. The assumptions made must be stated, for instance if current or expected rig rates are used.

4.2.9.6 *Field well abandonment cost*

Once a well has been evaluate and given associated estimates for costs related to location, phases, complexity and phase spread cost it is fairly simple to integrate the factors to determine a likely duration and cost for the abandonment of the well and summarizing all wells to get an estimate for the entire field. The process can be summarized as illustrated in Figure 29.

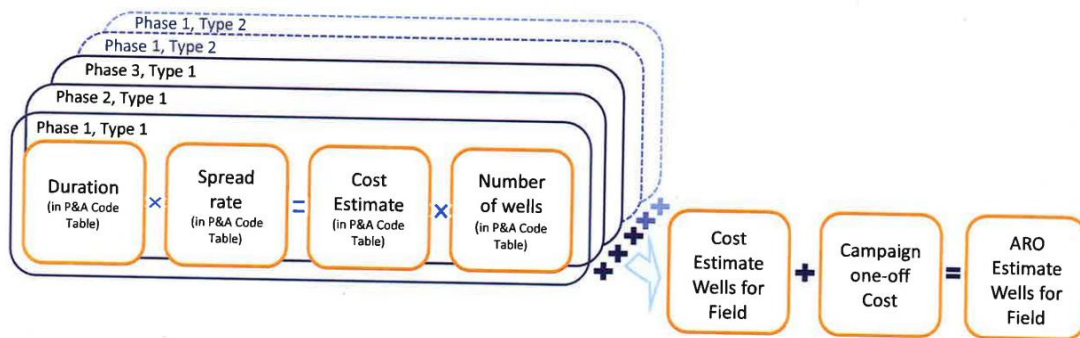


Figure 29: Illustration of cost estimation process [37]

4.3 DNV GL – RP-E103 – Risk based abandonment of offshore wells

In April 2016 DNV GL published a new, globally applicable recommended practice (RP) for permanently abandoned well which gives a risk-based perspective on P&A. This is a contrast to the traditional prescriptive methodology demonstrated in the previously described standard and guidelines. The background for developing a different approach to P&A is that no wells are equal and DNV GL suggest that they do not all need the same number, type and size of barriers to be deemed safe and protect the environment. By introducing a risk-based approach, tailor-made design solutions can be made which better fits the different wells and allow cost-savings to be gained for the least critical wells. Estimates suggest potential cost savings of more than USD32bn on the NCS alone, and even more globally [38]. Systematic assessment of the well abandonment design against defined acceptance criteria to ensure safety to environment and maintain safety standards is the objective of performing a risk-based abandonment assessment.

“The recommended practise is intended to provide an alternative approach, based on functional requirements and risk acceptance criteria to assess abandonment designs. This is consistent with offshore engineering practice and is intended to facilitate cost efficient solutions including the development of new technology. By calculating the risk levels for the proposed solutions and cross-checking them with the risk acceptance criteria, more cost-effective solutions can be identified and implemented.” [39].

Advantages to the methodology are that it has:

- Explicit criteria for environmental protection
- P&A spending concentrated on higher-risk wells
- The ability to optimise well abandonment design
- Flexibility to implement new plugging technology in the future
- Site specific considerations

The RP is divided in 2 sections where the first section is an introduction and the second is a risk assessment framework for well abandonment.

4.3.1 Section 1 – introduction

In general, the RP is meant to be a basis for decision-making and it presents practices and principles for:

- establishing site specific environmental risk acceptance criteria
- confirming compliance with safety criteria for the installation/field
- how to determine the functional requirements for materials used in permanent well barriers

- how to differentiate the environmental risk exposure relative to hydrocarbon composition.

The RP covers permanently abandoning offshore wells and is not applicable for neither onshore, suspended or temporarily abandoned wells. The requirements presented are intended to be subordinate to local regulations.

The RP differentiate between the three verbal forms *shall*, *should* and *may*.

Shall – indicates a mandatory requirement to be followed for fulfilment of compliance with the RP.

Should – verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but no necessarily required.

May – indicate a course of action permissible within the limits of the document.

The definition of these verbal forms is equal to the NORSOK D-010 definitions of the same terms.

4.3.1.1 System description

The RP gives a description of the systems referred to in the RP which include offshore wells, their surrounding geology and marine environment. This is illustrated in Figure 30, copied from RP-E103.

Marine environment: The marine environment includes the seafloor, the water column and the sea surface. All wells interact with the marine environment to some degree, including abandoned wells. When wellbores are in place they create a preferred pathway for gas migration which results in natural seepage tending to concentrate around wells. Seepage can also occur from hydrocarbon located deeper in the well, and the main focus for P&A is to prevent the heavier hydrocarbons from reaching the marine environment. Hydrocarbons may be naturally occurring in the ecology, i.e. methane gas which provides nutrition, or they may be heavier types for which there is a limit for how much is allowed in seawater/sediment.

Geology: The geological sequence above an oil or gas reservoir is referred to as overburden, which may contain quantities of hydrocarbons in certain formations. Hydrocarbons, as well as all pore fluids, are able to move within the geological sequence but is limited by sealing formations that have low permeability relative to other formations. These seals may be compromised by natural processes such as faulting or overpressure, or they could be man-made by drilling activity.

Wellbore: The wellbore provides a conduit for production from, or injection to a reservoir. A well penetrates the overburden when accessing a reservoir and it provides a potential passageway for pore fluids to migrate to the seabed.

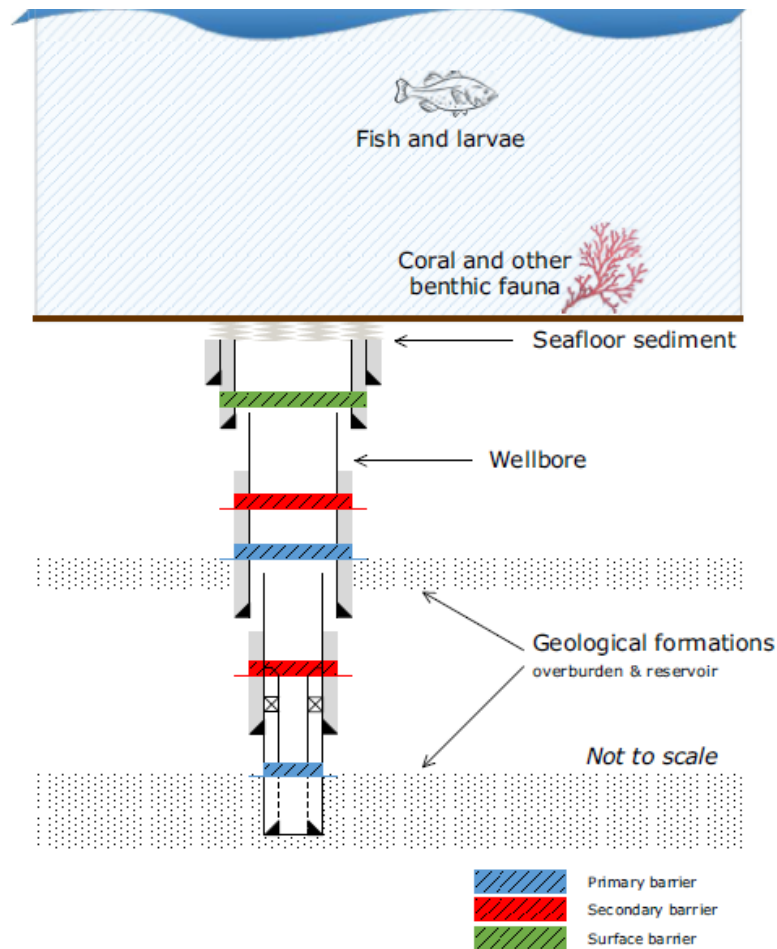


Figure 30: The main system components of P&A wells [39]

4.3.2 Section 2 – Risk assessment framework for well abandonment design

Risk based approach to well-integrity is already being advocated for in international standards where they suggest that this approach is used to assess the wells relative to their potential loss of containment. By issuing the RP-E103, DNV GL applies this approach to the permanent abandonment of offshore wells by including threats to long-term well integrity.

4.3.2.1 Establishing the risk context

Risk assessment of well abandonment establish, analyse and evaluate the risks involved. A systematic approach is used to identify main factors of the risk profile. The analysis will provide a result which may find the proposed design suitable, or mitigating measured might need to be implemented, but either way it gives valuable knowledge. The assessment may be qualitative or quantitative but either way it should include both environmental and safety risks. The focus of RP-E103 is a quantitative approach.

It is important to establish the context before any of the elements included in the risk assessment period is started/executed. The context should also be updated throughout the process. For P&A purposes, an evaluation of flow potential of the producing reservoir, in-situ formations and between formations (cross-flow) as well as permanent well barrier solutions should be performed.

Figure 31 illustrates the main elements in a well abandonment risk assessment and the main categories for input are:

- Well specific data
- Geology data
- Environmental data
- Met-ocean data

The RP provides a sample input of data in its appendix which is copied and showed in Appendix C. When performing the risk assessment, documentation of the activities should be provided in a manner which is traceable, transparent and consistent. The assumptions, inputs and results of the analysis should be quality assured as part of the risk assessment.

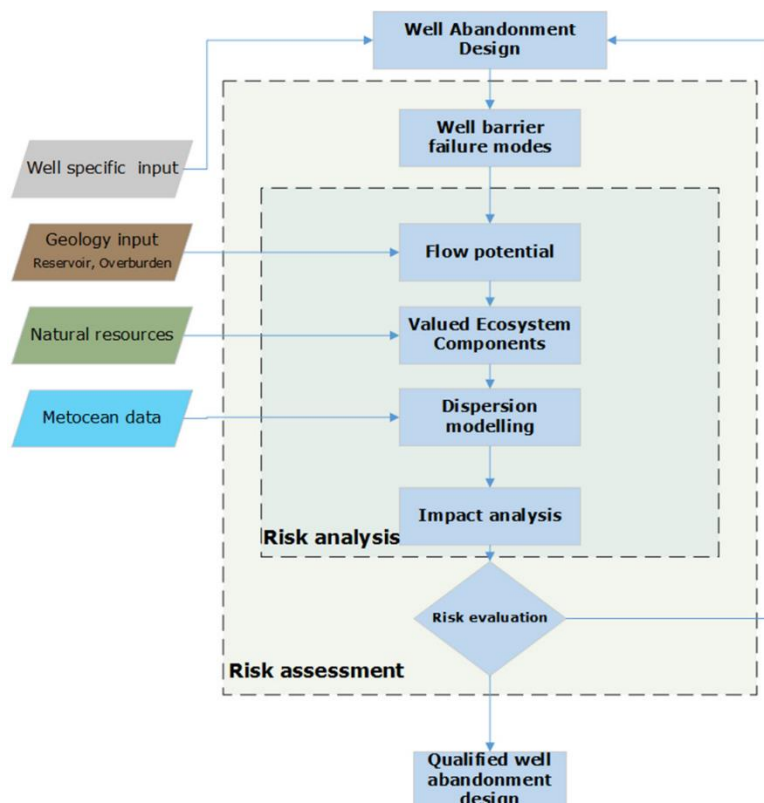


Figure 31: Risk Context for P&A [39]

4.3.2.1.1 Well abandonment design

With regards to the well abandonment design RP-E103 states that the main objective should be to prevent environmental harm until the original geological barriers are re-established at the same time as ensuring safety standards are satisfied. The design should be as detailed as reasonably practicable, be based on the risk context and maximum expected flow and it should be recognized that all wells are unique when abandoning multiple wells.

4.3.2.1.2 Flow potential sources

An overview of formations that identifies, examines and describes hydrocarbon-bearing formations with their associated flow potential should be made. In this context, flow potential is defined as “*a hydrocarbon-bearing formations containing moveable hydrocarbons large enough to have a potential environmental or safety impact.*”[39]. Table 8 shows how the flow potential should be categorized.

The categorization should be performed for a distribution of the expected flow potential for the identified hydrocarbon-bearing formations, including re-charge, re-development for hydrocarbon extraction or other issues such as geothermal project and storage of energy or CO₂. Potential consequences to the environment should be mitigated with permanent well barriers in compliance with ALARP principles for formations categorized with moderate or significant flow potential. The RP refers to the *UK Oil & Gas Guidelines for the Abandonment of wells* for further guidelines on this subject.

For multiple hydrocarbon-bearing formations located within the same pressure regime, they may be treated as one formation *if* the cross-flow is in accordance with the environmental acceptance criteria. In general, cross-flow between formations should be prevented.

Table 8: Categorization of flow potential in hydrocarbon-bearing formations

Categories of flow potential	Definition
No or limited flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future cannot under any circumstances have an environmental or safety impact
Moderate flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future may have an environmental impact, but no safety impact
Significant flow potential	Hydrocarbon-bearing formations where moveable hydrocarbons present or in the future may have both environmental and safety impact

4.3.2.1.3 Permanent well barrier principles

When designing the permanent well barrier, it should be made fit-for-purpose and consider the effects of any reasonable foreseeable chemical and geological processes. The function of a

permanent well barrier is to control formations with moderate or significant flow potential, the duration requirement for the barrier should be site specific and depend on the barrier's design. One element of the permanent well barrier should be the surrounding formation which should have a higher integrity than the potential pressure below it and be impermeable at the depth of the barrier.

Depth requirement to the barrier is that the formation should be strong enough to contain the hydrocarbon-bearing formations. The barrier may consist of any material or combination of WBE provided it fulfil the following functionalities [39]:

- withstand the maximum anticipated combined loads to which it can be subjected
- function as intended in the environments (pressures, temperature, fluids, mechanical stresses) that can be encountered
- prevent unacceptable hydrocarbon flow to the external environment.

Comment: The RP use the phrasing “any reasonable foreseeable” and not the phrasing “eternity” for describing the permanent well barrier design – different to NORSOK. It also states duration of barrier should be site specific – not eternal perspective

4.3.2.1.4 Number of well barriers

The illustrations in Figure 32 below shows examples of different well abandonment design with different flow potentials. As seen in the figure the number of barrier depend on how big the flow potential is, which is evaluated based on risk analysis. The RP recognizes that having multiple independent barriers can increase the level of reliability. The primary and secondary barrier can be combined into a single barrier provided it maintains the same level of effectiveness and reliability as two individual would. There should also be a surface barrier in place to isolate flows from the wellbore in addition to the primary and secondary barrier

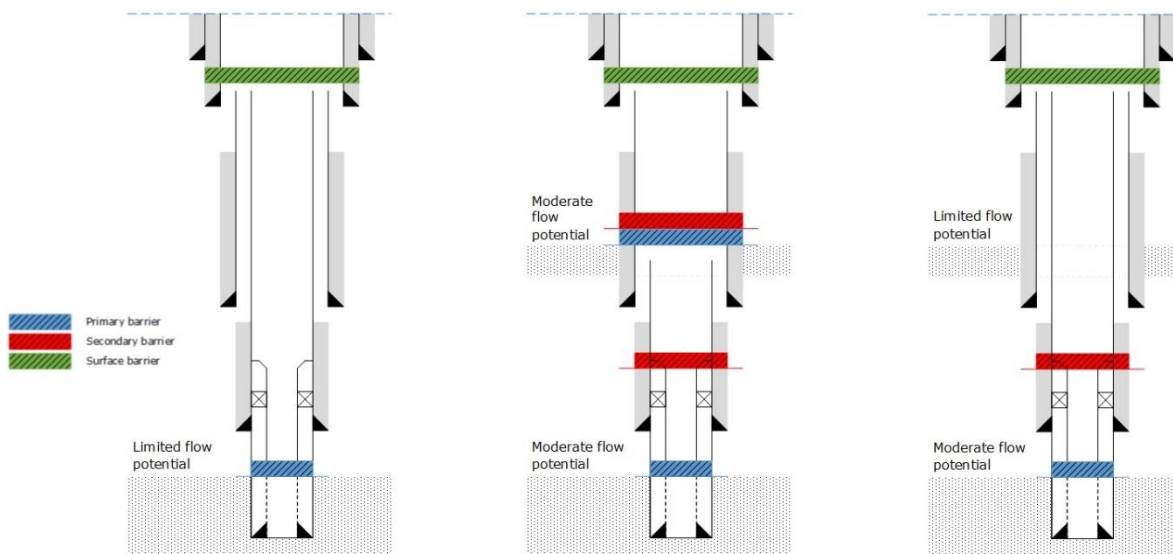


Figure 32: Examples of well abandonment designs in DNV GL- RP-E103 [39]

4.3.2.2 Permanent well barrier failure modes

There should be a failure mode identification for each well abandonment design where the process should consider all relevant failure modes, and document identified threats, events and consequences in a structured manner. The process of failure mode identification should include evaluation of potential cost savings, and other upside potential in addition to the following which is taken from DNV GL-RP-E103 [39];

- identification of failure and degradation mechanisms and categorisation of threats according to established consequence categories
- identification of additional threats related to unique aspects of the well abandonment design, for example:
 - o unique features of the subsurface under consideration
 - o technical or organisational aspects that are outside the well operator’s experience.
 - o well completion design and integrity.
- identification of interdependencies between different failure modes, including the potential for cascading
- identification of effects that may increase likelihood of occurrence or severity of consequences

Appendix D is copied from DNV GL-RP-E103 and lists potential failure modes for analysis.

4.3.2.3 Risk analysis

The aim of a risk analysis is to increase understanding of risks meaning the characteristics of the risk itself, the likelihood of occurrence and the severity of the potential consequences. For P&A purposes the risk analysis should include safety and environmental risks and should be performed on the failure modes identified. If reliable sources of data are available they should be incorporated in the analysis and if there is limited data, or the data is uncertain, assumptions may be utilized. If assumptions are applied, they should be conservative.

The risk analysis should contain an analysis of the *flow potential* to determine the maximum flow potential and hydrocarbon content/composition within formations penetrated by the well and use this in the assessment. The objective is to estimate the magnitude of the consequence of hydrocarbon flow. The likelihood of flow should also be part of the risk analysis in order to characterise the identified failure modes with respect to likelihood of occurrence. Level of detail depend on whether it is a qualitative or quantitative analysis. The RP refers to *ISO 31000* for guidance on qualitative vs. quantitative risk analyses.

The next step is to perform an analysis of the *valued ecosystem components* (VEC's) which aims to create a site-specific map and categorization of the geographical distribution of valued resources and habitat around a well. The results are used in the risk analysis.

To calculate the transport of the identified hydrocarbon flow potential, three-dimensional dispersion modelling should be used which calculate and records the distribution of mass and concentration of hydrocarbons in the water and sediments. A probabilistic approach should be used to give insight on how potential seepages will behave under a wide range of ocean conditions.

The last part of the risk analysis is to perform an impact analysis. The consequence part of the risk picture is a combination of the results of the flow potential analysis and the dispersion modelling. The likelihood portion is produced and incorporated in the analysis of the flow potential.

The environmental risk picture can be built by assessing the potential environmental impact from the degree of overlap between hydrocarbon concentrations and defined VEC's. The safety risk picture should be compiled from the likelihood and consequence of safety risk for the well abandonment design.

The output from the consequence analysis (flow potential, mapping and valuing of VEC's and marine dispersion) and the likelihood analysis gives the risk result for each specific well abandonment design.

4.3.2.4 Risk evaluation

After the analysis is done the results need to be evaluated against defined risk acceptance criteria with the purpose of aiding decision-making. Re-analysis and revision of the well abandonment design may be necessary should the result of the risk evaluation be that the design is not applicable and measures to reduce risk are required.

Risk acceptance criteria should be made both with regards to environment and safety. The environmental risk acceptance criteria should be based on the proportion of VEC(s) exposed to a defined threshold value for hydrocarbons and the probability that the proportion of VEC(S) is exposed to a concentration above the defined threshold value.

The safety risk acceptance criteria depend on whether it is a platform or subsea well. After completing P&A on a subsea well, safety risk may not be relevant whereas for a platform well the established risk acceptance criteria for the platform should be applied. There should be a categorisation of wells planned to be permanent abandoned based on their potential for adverse safety consequences.

Environmental and safety risk evaluations should be done to compare the risk acceptance criteria and the results of the risk analysis. Various designs may be compared to the risk acceptance criteria and to each other before deciding which solution is the optimum one, and if changes need to be done to the design before moving forward. If changes are made, the design should go through another risk assessment process to quantify the impact the changes have. The results may also function as support for decision-making in a cost-benefit analysis.

4.3.2.5 Treatment of uncertainties

As with any other risk analysis there will be uncertainties present and care should be taken to ensure that the results of the risk assessment possess reasonable accuracy. If there are significant uncertainties present, sensitivity or scenario analyses should be performed. Depending on their influence, critical parameters might be pressure, hydrocarbon volume and temperature.

With respect to quantification of uncertainty a set of weighted probabilities might be interpreted through a probability distribution. How to establish a fitting distribution will depend on the knowledge available and if it changes over time.

Available data for planning P&A should be studied for each potential well and if critical pieces of information which may reduce uncertainties exist, it should be identified and recorded.

4.4 Matrix summarizing requirements in different documents

The matrix presented in Table 9 summarizes the main differences found in the three documents. These differences will be further discussed in chapter 5, with the focus being on discussing differences between NORSOK D-010 and the three UK Guidelines.

Table 9: Matrix summarizing main differences in documents

	NORSOK D-010	UK Guideline	DNV GL RP-E103
<i>Structure</i>	Prescriptive. Intended to replace company regulations. Covers several topics	Prescriptive. Intended to support development of company regulations. Covers only P&A	Risk-based. Intended to support decision-making in companies. Covers only P&A
<i>Phrasing/wording used</i>	Lot of strict wording (shall) and unrealistic perspective (eternal)	More suggestive wording (should) and realistic perspective (foreseeable)	More guiding wording, but some strict words used for certain areas. Realistic perspective
<i>Well Barriers</i>	Strict requirements to length and number. Same requirements for all wells.	Strict requirements to length and number. Slightly different requirements than NORSOK. Opens for some risk evaluations.	Length and number should be decided by a risk-based approach. Each well treated individually.
<i>Material used as barriers</i>	Cement and formation. Other materials may be used but are not described.	Cement, formation and other materials. Separate guideline on materials qualification.	Any material may be used provided it fulfil the required functionalities.
<i>Verification of barriers</i>	Logging or original records. Not very detailed descriptions.	Logging or original records. Provides detailed tables for verification process.	
<i>Categorization of wells</i>	No categorization	P&A code for determining work scope	
<i>Cost Estimation</i>	No guiding on how to perform cost estimation	Separate guideline on cost estimation	
<i>Risk considerations</i>	Risk briefly mentioned	Risk assessments mentioned to a larger degree than NORSOK	Purely risk-based approach
<i>Considerations of initial well design</i>	Briefly mentions importance of initial design	Emphasises the importance of initial design	

5 Discussion

So far in this thesis three different documents providing regulations and guidelines for P&A operations has been presented, in addition to challenges and technological advancements within the field. This chapter aims to discuss the differences found in the regulations and the potential the new technologies might have.

5.1 Differences in regulations and guidelines

When reading and comparing the different regulations and guidelines to each other there are several similarities and differences that can be pointed out. This section will first discuss the issues that the author finds most interesting when reading and comparing the UK guideline on abandonment of wells and the chapter on abandonment activities in NORSOK D-010. The DNV recommended practice will mainly be discussed at the end of this section and in relation to the NORSOK D-010.

5.1.1 Structure and intent of the documents

NORSOK D-010 is an extensive document covering well integrity in all drilling and well operations where well abandonment is only a small portion of the entire document. The chapter on abandonment covers both temporary and permanent abandonment with the focus of this thesis being permanent abandonment. The part of the NORSOK which covers permanent abandonment sums up to roughly 30 pages whereas the UK guideline is a 47-page document dedicated to well abandonment, with two additional documents used as reference for cost estimation and material qualification.

The UK guidelines covers a wider range of special considerations and well conditions that may exist in a well while the NORSOK focus more on the well barrier elements and their acceptance criteria. Another issue is that the UK Guideline is just that, a guideline. Hence it is more advisory in its nature and is meant to guide the operators so that their operations will be in compliance with *The Offshore Installation and Wells (design and construction) Regulations*. The UK Guideline is equal to the NORSOK D-010 in that it provides minimum criteria/requirements to ensure full and adequate isolation of formations fluid when abandoning a well. However, where the UK Guidelines aim to support well-operators in the decision-making and anticipate that well-operators will wish to develop their own standards and procedure (with a basis in the guidelines), the NOROSK standards are developed to replace individual oil company specifications and provide a common standard to be used on the NCS. This basic difference in the intent of the two documents contribute to the differences that will be identified and discussed in this chapter.

The NORSOK standard is however also in its nature a recommended approach to interpret and fulfil regulatory requirements issued by the PSA, despite that it feels very definite and final when reading it. More on the phrasing/wording will follow in the next sub-section.

5.1.2 Phrasing/wording used

When reading the documents it's apparent that the NORSOK standard uses a more definite language for describing the requirements found in the standard by using the term *shall* frequently. The term *shall* is defined to indicate requirements strictly to be followed. However, due to that the entire standard is not an actual legislative requirement but a way of fulfilling the requirements, the term can be argued to be somewhat misleading. Here, the UK guideline is more suggestive by most often using the word *should* which indicates a recommended route but it is not necessarily the only right option. To be more suggestive instead of definite may open up for use of alternative, and new, methods and approaches resulting in the P&A being more effective and cheaper.

Another word that sets the two documents apart is that the NORSOK standard states that barriers should be functional for *eternity* whereas the UK guideline primarily uses the phrasing *foreseeable future*. The NORSOK use of the word *eternity* gives an unrealistic expectation to the integrity of the barriers. Nothing lasts forever and over a period of time nature will run its course and the barriers will be likely to degrade and/or the surrounding formation will re-establish the caprock as it is already known to be doing in the annuli between casings and formations.

A potential improvement to the NORSOK D-010 with respect to the structure and wording chosen, could be to issue a separate standard on the abandonment activities and make this document more thorough and comprehensive with respect to content, like the UK Guideline has in terms of the supporting guidelines on material qualification and cost estimation. This could be beneficial as P&A is becoming increasingly important and differs from other well integrity issues covered by NORSOK D-010 (most other activities require pressure control equipment such as BOP, XT etc).

It could also be beneficial to not use wording like *shall* and *eternal* but rather make the document more suggestive in its nature while maintaining fulfilment of the legislative requirements issued by PSA.

5.1.3 Well barriers

For when barriers are required the definitions in NORSOK and UK Guideline are relatively similar. The NORSOK D-010 states that well barrier is required to isolate *a source of inflow* from surface/seabed, where source of inflow is defined equal to reservoir, i.e. a formation which contains free gas, movable hydrocarbons or abnormally pressured water. Further, hydrocarbons are defined as movable unless they are residual or have extremely high viscosity, such as tar. In UK guideline, a

barrier is required to isolate all penetrated *zones with flow potential* from surface/seabed. A zone with flow potential is a sequence or rock capable of flow of fluids, and previously explained in section 4.2.3.

With respect to the number of barriers NORSOK states two barriers shall be in place for any hydrocarbon-bearing formations and for abnormally pressured formations with potential to flow to surface. In UK guideline two barriers are required if a zone is hydrocarbon-bearing or over-pressured and water-bearing. Again, the requirements are similar, though phrased differently. A comment on this requirement, valid for both, is whether it is necessary for two barriers to be in place when there is no hydrocarbon present even if the formation is over-pressured. This is an issue that could be further investigated and considered in future issues as eliminating a barrier for these wells/section of wells could reduce the costs and time associated with the abandonment activity. An approach that could be implemented is that this type of conditions should be risk assessed to evaluate the risk if some nonhydrocarbon-bearing flow was to escape from these sections and which potential consequences it would have.

The length and depth requirements for cement/plug material are in principle the same for both with respect to the need for formation integrity on outside of the casing etc, although they operate with different lengths (NORSOK requires 50/100 MD whereas UK Guideline requires 100ft typically 500ft) as outlined in chapter 4.1.5 and 4.2.4.3. To the author it appears that these requirements are not very well funded in research and have been chosen based on that it seems to be enough (empirically decided). It should be considered putting more scientific research into this field and update future issues of both UK Guideline and NORSOK. The length of a plug should not be considered very important as long as it serves the purpose of creating a permanent barrier. Again, there could be considerable savings of both cost and time if the cement/plug job did not need to be as extensive as it is today. Also, it might open up for the use of alternative methods/materials which may be easier to install in the well if the current length requirement was revised.

5.1.4 Materials used as barriers

As mentioned cement is commonly used as plug material but it is not necessarily the best material for this application and this is recognized in both standards, but to a different degree. Where the UK Guideline has a separate guideline that acknowledge and encourage development of alternative materials, the NORSOK mentions that other materials may be used as plugs but does not give any in depth description on types of materials or how to proceed if other materials are proposed used. NORSOK do contain a separate Well Barrier EAC table called “Material Plug” which refer to the UK Guidelines “package” containing all three UK Guidelines presented in this thesis. It is likely that it

mainly refers to the Qualification of Materials Guideline but the NORSOK standard could be clearer on this matter.

The oil and gas industry is to a large extent fairly conservative and this might be a reason for why the industry are cautious about testing and implementing alternatives to cement. “Why change something that is working” seems to be a mindset that is prevailing. With that being said, the operators on the NCS are to some extent known for being open to new technologies which has resulted in Norway being one of the best with regards to e.g. subsea technology. It seems however that there is larger reluctance towards testing and qualifying new technologies within P&A. This might be due to the strict requirements that exists in terms of keeping an *eternal* perspective and as recognized in the UK Material Guideline there are uncertainty with regard to the long-term integrity of alternative materials.

It could be beneficial to develop a separate NORSOK guideline concerned with the qualification process of alternative materials and methods for barriers/barrier plugs. This should be done in accordance with PSA regulations and it might be an idea to get some guidance from DNV GL which has experience in the field, in addition to using the UK Material Guidelines as a basis. Such a document should be updated on a regular basis and include the most recent methods developed with respect to material type and new plugging technology. If such a guideline existed it would be easier for companies/operators to properly qualify new materials.

A material that is gaining momentum in the industry is using formation as barrier for the annulus between casing and formation. This is as stated in section 3.4.2.1 something that cannot be predicted but is known to occur under the right conditions. Both NORSOK and UK Guideline recognizes this and has directions on which requirements and qualification methods to be used for formation to be accepted as part of a permanent barrier. The requirements and qualifications methods are similar for both, stating that the formation requires qualification through two different loggings, pressure testing and leak-off test. One difference is that that UK Guideline requires the length of the seal to be 100ft while NORSOK requires it to be 50m MD with 360 degrees of qualified bonding. Again, the numbers seem empirically decided and some research should be put into the length requirements as discussed above in section 5.1.3.

5.1.5 Verification of barriers

As it is required that well barriers extend to the full cross-section of a wellbore both UK Guideline and NORSOK states that verification of the cement on the outside of casing is necessary. For verifying the top of cement, both documents state this should be done by logs or by documentation from original cement job (and calculations) with the difference being that UK Guidelines suggest a longer

interval of continuous cement to account for uncertainties if previous documentation are used. If logging is used the length intervals are close to equal. The reason for the different length requirements are not clear. It might be a result of the UK Guideline just being more conservative on this matter to be on the safe side, or it could be that the NORSOK writers feel more confident in the accuracy of the original documentation than the UK Guidelines writers do. If the latter is the case, it could be some substance to it as the Norwegian industry is substantially younger than the UK one. The wells on the UKCS are older and hence there might have not been the same requirements to documentation established when they were drilled as to the younger NCS wells. Also, when starting drilling, Norway learned from relatively experienced foreigners but under Norwegian Government control and hence there might have been more stricter requirements to documentation already from the beginning of the drilling activity whereas the UK industry had to learn more as they went in the beginning.

For verification of the cement quality in the annulus the NORSOK is somewhat inconclusive. It states logging of cement shall be performed for casing cement but does not give any more detailed description. Here, the UK Guideline states that sealing ability of the casing cement should be evaluated through the methods described in section 4.2.5. In addition, the UK Guideline provides two tables for aiding in the verification process which can be found in Appendix A and B. The approach outlined in UK Guideline gives more clear guidance on how to qualify the sealing ability of the casing cement and future revisions of the NORSOK should consider adopting the formulations used in UK Guideline. From what the author gathers the 4th revision of NORSOK is clearer than previous revision which indicates that there is a process in place but there is still some improvements that could be done for the next revision.

As outlined in section 3.3.4 there are some challenges/uncertainties related to logging of cement and an alternative to logging for qualifying the sealing ability of the annulus cement could be to actually test the annulus. This is mentioned in the UK Guideline by stating the sealing capability should be assessed among other by *absence of sustained pressure during the life cycle of the well*. The interpretation of this is that if there is no pressure build-up observed during an annulus test then this can be considered as proof of the sealing ability. This could be argued to be valid especially for older wells which has been sealing for up to several decades already and there is no reason why they should not continue to maintain the seal. With respect to the *eternal* perspective in NORSOK this should be considered sufficient. Another possible alternative could be to perforate the annulus cement and run pressure test to see if the barrier holds a sufficient seal. These alternatives are just simple suggestions but should be further looked into by qualified persons and potentially included in

a revision of the NORSOK D-010 with the aim being alternatives to logging in cases where logging is difficult or do not provide a definite result.

5.1.6 Categorization of wells

In section 0 a system found in the UK Guideline for categorizing abandonment activities based on their location, complexity and phase is described. This system provides a mean of eliminating differences between operators and makes it easier to get an overview of the well status and work scope independent of which operator/company is in charge of the well. The reason why such a system is not already implemented in Norwegian standard is unknown and the author cannot see any good reason as to why the NORSOK standard on well abandonment should not develop such a classification system as well. A potential reason a system is not developed could be that the industry does not feel confident in developing it due to lack of experience within the P&A field. Another reason could be that it has not been considered important as P&A has not been very high on the agenda and thus development within the field has not been prioritized. To compensate for this, the system can be based on the UK Guideline which is more experienced than Norwegian operators and thus some of the potential uncertainty regarding *how* to develop such a system may be eliminated.

The benefits of implementing such a system could include but not be limited to;

- Giving a simple and efficient overview of the estimated work scope for P&A.
- It can be used as input in cost estimation and as experience is gained estimates for different types of categories can be updated if needed.
- Can be used for both single wells and for entire fields with just minor adjustments as in the UK Guideline.
- Provide guidance on when using a simpler monohull vessel is possible and when a rig is required.
- Evaluate P&A operations after completion and compare whether the work scope was correctly predicted or not. Use as reference for future operations of similar character.
- Avoid different systems in different companies and thus making it easier for hired sub-companies (service providers) to estimate equipment and time needed to carry out operations.
- If combined with an overview of all wells in need of P&A on the NCS it could provide a simple indication of the combined work scope and complexity in the years to come. This could give a clearer indication of which resources are necessary in terms of vessel and/or rig and equipment, and organize P&A campaigns in a more efficient way.

- Companies can use the categorization to compare the P&A operations both to other companies and within the company.
- Potentially easier for knowledge and experience transfer as a common code can be used for comparison and development.

5.1.7 Cost Estimation

As described in section 4.2.9 there is a separate guideline on cost estimation in relation to well abandonment that has been issued by UK Oil and Gas and can be seen as a supporting document to the UK Guideline on well abandonment. This guideline provides operators with a basis for estimating the cost and duration of operations when abandoning a single well or a field. The estimates are based on relatively simple methodologies and it is emphasized that the estimates must be updated and increase their level of detail as the abandonment date is approaching.

In NORSOK D-010 there are no such document which gives guidance on cost estimation, although the UK Guideline states that it is based on industry experience on both the UKCS and the NCS. As P&A is a high expenditure operation one should think that such a guideline would be beneficial to have for the operations on the NCS as well. The UK cost guideline utilize the previously discussed P&A categorization and hence the guidelines as a whole provides a more complete image of the abandonment activities and associated considerations than the NORSOK D-010 does. Current practice for several operators is to use the same methods for estimating well abandonment activities as for general drilling and well operations but this is not very accurate as P&A operations differs a great deal from said operations. Based on this, the Norwegian sector could benefit from developing its own guideline for cost estimation of P&A operations. The benefits could amongst other be better estimates as the method is tailor-made for the application which in turn with give a more realistic indication of the costs involved in a project/campaign. It is however important to remember that estimates can only be as good as their basis, and to account for uncertainties, risk and unpredictable events the method should use probabilistic modelling. This would also take into consideration that all wells are unique and the abandonment activities will vary on a well-to-well basis and they could be very complex.

As mentioned above, the estimates should also be updated on a regular basis (UK Guideline propose yearly) in order to account for changes and incorporate a higher level of detail as the end of production is approaching and more variables are known. However, this does not mean that cost estimates for well abandonment should be developed only in the last producing years of a well. Cost estimation of well abandonment should be incorporated in the well design from the beginning, which could potentially keep the final costs down if abandonment costs are considered in initial design.

Also, estimates will tend to be more accurate if started early and revised as COP is approaching. Due to this, the UK Guideline describes the estimation process to start more than 10 years before COP. The estimates are updated regularly and as COP approaches they become increasingly detailed and incorporate a larger pool of wells into the estimation process. This approach should be adopted for a NORSOK version as well where the Norwegian accounting regulations are taken into consideration in addition to PSA regulations.

5.2 Considerations of P&A in initial well design

When looking back it is evident that future P&A has not been high on the priority list when designing and drilling the wells. The cement jobs are often poor, or non-existent and documentation is very often lacking. This could be because it was never recorded in the first place or it has been lost during the decades since the well was drilled. This is often the case for wells that have changed owners during their lifespan. The result of this is that when the time comes for P&A of the wells, the external well barriers (casing cement) often need to be re-established. In order to do this, section milling or other operations are required to gain access to the annulus. These operations are as described both time consuming and costly. Due to this, the initial well design should take future P&A into consideration, especially when it comes to verifying and recording the quality of the initial cement jobs. This could potentially save significant amount of time and money during P&A as it could result in only an internal plug being needed to have full cross-sectional barriers.

In the most current revision this is included in both UK Guidelines and NORSOK D-010. For the section on well design, the NORSOK states that the design process shall cover the complete lifespan including permanent abandonment and the design basis should address P&A solutions. The UK Guideline recognizes that *“the key to efficient and effective abandonment operations often lies with the soundness of the initial well design and effectiveness of the primary casing cementations. The benefits of successful cementation will include an easier well abandonment ”* [34]. Further, that a well are designed so that it can be abandoned in a safe manner is a legislative requirement in UK.

These recognitions should result in wells being drilled in the future having P&A better incorporated in the initial well design and put higher emphasis on the initial cement job. Ideally it should also be planned where the future permanent barrier can be set, and ensure that annulus cement has good quality in these sections. Location of future barrier may also be considered with respect to solutions chosen, and positioning of control lines etc. If they could somehow be installed in a manner that would not require entire tubing and control lines to be pulled for P&A it would reduce the work scope of P&A significantly.

5.3 Incorporation of risk-based perspective

In section 4.3 an alternative to the traditional prescriptive methods used in P&A was described. This alternative is a recommended practice issued by DNV GL which presents a risk-based approach to abandonment of offshore wells. The RP challenges the current standard where the requirements are the same for all types of wells and is therefore in support of a paradigm shift happening in the industry which acknowledges that P&A should be differentiated on a well-by-well basis opposed to having strict prescriptive requirements.

In NORSOK the requirements are very prescriptive and risk is only briefly mentioned in relation to that design and operational risks shall be assessed. The standard does not consider that the entire P&A process can be viewed from a risk-based perspective and simultaneously maintain the PSA requirements. In the UK Guidelines, a risk-based approach is incorporated to a larger extent for some issues, but also here the prescriptive approach with set number, type and size of barriers is the governing approach.

The reason why NORSOK is such a prescriptive document could be several. One reason could be that risks traditionally have not been researched a lot resulting in risk and risk analysis not being properly understood and thus implementing such an approach is deemed to have a too high risk in itself. However, in recent years a lot of research has been put into understanding and identifying risks throughout the industry and now a risk-based approach should be considered a more valid approach than it has been.

When reading through the RP it is evident that it incorporates many of the same requirements that the NORSOK D-010 does but with a different approach. Like in NORSOK the overall objective of the RP is to prevent unintentional flow of hydrocarbons from a wellbore to the surrounding environments once a well is abandoned. Barriers must be placed in the wellbore to ensure that this is fulfilled but the RP states that the number, type and length of barriers should be based on the flow potential and other parameters identified in the risk assessment. Here it differs from both NORSOK and UK Guidelines which has strict requirements to the length of barriers and states that two barriers must be in place for any hydrocarbon-bearing or over-pressured water-bearing formations with flow potential. The RP acknowledges that these conditions might not constitute a need for two barriers in all wells, in addition to the surface barrier.

Further similarities to NORSOK is that the RP states that formation at the base of the barrier is strong enough to contain the hydrocarbon-bearing formations, but it does not give any requirement to the length of the interval with formation integrity like the NORSOK does. In addition, the RP states that the formation, with higher integrity than the potential pressure below, should be an element in the

permanent barrier and that the rest of the barrier may exist of any material as long as it fulfils the functionalities listed in 4.3.2.1.3. There is no requirement to the depth of the barrier as long as the formation is strong enough in the area. This differs from NORSOK which focus on cement as barrier material and only briefly mentions that formation may be used as part of the well barrier in the annulus.

Another difference which is commented on previously is that the RP uses the phrasing “*any reasonable foreseeable*” and not “*eternity*” when stating requirements for the barriers. The wording used in NORSOK have been discussed previously and will not be repeated here, but it is interesting that the RP, like UK Guidelines avoid using the term eternity.

The risk-based perspective could be beneficial to incorporate in the NORSOK as this acknowledge that all wells are unique to a greater extent than the current revision does. Also, risk assessments are gaining momentum as a sound approach throughout the oil and gas industry and it could potentially give huge cost and time savings in P&A operations. If the type, number and length of barriers could be decided based on a sound risk assessment it could result in less material used for plugs, less time on each location and vessels could maybe be used to a greater extent which would free rigs to go where they are truly needed.

A risk based-approach may also to a larger degree than NORSOK does account for uncertainties in the available data in that it is included in the nature of a proper risk assessment. To do a sound risk assessment and identify potential consequences for different scenarios and their associated likelihood would aid in evaluating the work scope needed for each abandonment. Further it could result in safer operations for personnel involved and for the environment. By acknowledging that each well is unique with its own set of consequences, likelihood of occurring and mitigating measures, the P&A activity could be tailor-made for each well. After experience is gained, there will be likely that some pattern arises for similar type of wells and this could be further used to make the P&A activities more effective and save costs. However, it is important to emphasize that an individual risk assessment should be carried out for each well and field.

There are several professionals with great experience within the field of risk assessment in the oil and gas industry and these should be included in the process if a risk-based approach is to be given more weight within P&A.

5.4 Technological developments

In addition to the main objective of comparing regulations, this thesis has described some new technologies which is being, or has been, introduced in recent years that aims to make P&A operations easier and more cost-effective to perform. These are aimed to overcome some of the challenges described in this thesis. Common for the technologies is that they aim to eliminate the need for a rig as they are associated with very high day rates and represent 40-50% of P&A cost, and should rather be used for drilling which has potential revenue for operators. This section will attempt to discuss potential benefits and issues with the technologies presented in section 0.

Within the industry as a whole there exist a certain reluctance towards adopting new technological advancements, due to that the current technologies are producing high profits. However, as mentioned, the Norwegian industry is one of the most innovative with respect to e.g. subsea technology and this mindset should be transferred to the P&A field. This should be done as P&A continue to be a high expenditure post for operators and unlike drilling activities there is no potential for revenue. With this in mind, there should be widespread wishes to make P&A operations as cost-effective as possible and implementing new technology should be a part of this.

5.4.1 Cooperation and combinations of technologies

As described in 3.3.7 there is an increasing cooperation within the market and ideally this should continue and expand so that different new technologies potentially could be developed as to fit together if possible. One interesting combination with respect to this could be combining e.g. the PWC tool and OWCT. The PWC tool is already accepted as an option to eliminate section milling but is commonly deployed on drill-string. If the OWCT and PWC tool could be made to accommodate each other, this could give additional savings in that a rig would not be necessary. Another potential cooperation would be to fit OWCT and the approach mentioned in section 3.4.3 which utilized gas injection to create buoyancy for pulling tubing by using wireline/CT. This combination could also eliminate the need for rig. The technological specifications of the systems are outside the scope of this thesis and as such there are several limitations/challenges to solve before this potentially could be realistic that will not be discussed here.

5.4.2 The PWC tool

As outlined in section 3.4.1 PWC is a method for establishing a cement well barrier without performing section milling to remove the casing. As mentioned, swarf can be very damaging for BOP and other equipment and when performing section milling it is thus required to have frequent inspections of equipment to ensure safety of personnel and environment. If section milling can be eliminated from P&A operations it would save time and money, due to both the actual operation and

less damage to equipment. The PWC technology is to date, one of the best options to section milling and it is increasingly gaining market in the industry. The technology has considerable future potential, especially if some issues could be resolved. These issues include, but are not limited to, the previously mentioned running it on CT/OWCT which could eliminate the use for drilling rig which is one of the focus areas in P&A technology. If the challenges with running on CT described in the section about PWC could be solved, it would give a basis for further development to making it possible to run the tool using OWCT.

Another issue in line with current trends is that more emphasis could be put on the risks involved with the technology. To the author it seems like all publications regarding the technology is only focusing on the upsides like time-savings and no swarf handling but very little attention is given the potential weaknesses of the system and which consequences this could have. Something that is a bit unclear to the author is whether it is possible to set two permanent barriers in one run. If this is not possible, this is something that should be considered as it could give additional time and cost-savings.

A final issue in relation to this technology is solving the challenge of logging through multiple casings as it would make the verification of the plugs set easier. This could also potentially eliminate the need for setting plugs in annuli if good cement is verified and thus PWC would not be necessary as only a plug within the casing is needed.

5.4.3 The OWCT system and potential combinations

As outlined in the section about the OWCT system the biggest advantage of developing this system is that it would eliminate the need for a rig for potentially all P&A operations. There are some challenges that need to be overcome for the method to reach its full potential as illustrated in Figure 10. Two potential challenges has already been addressed above. The first one is the challenge of setting cement in the annulus behind casings. This could potentially be solved by combining the OWCT system with the PWC technology. This would require further research and modification of both technologies and probably an operator, or other stakeholders, would need to be involved for financing the process. It would however be highly interesting if the challenges could be solved. This combination would also solved the issue of setting the barriers in the reservoir.

Another challenge which could be solved in combination with presented technology is the pulling of tubing. This could potentially be solved by the gas injection method that former Aker Well Services presented in 2013. As stated previously the author has not succeeded in finding information regarding this method published later than 2013 but the concept has potential and it illustrates how innovative thinking can make P&A more effective. The methods advantage is that it reduces the effective weight on the wireline caused by the tubing, which makes it possible to pull longer sections of tubing than

what would be possible using “normal” wireline. If tubing was to be pulled on traditional wireline it would require cutting the tubing into many small pieces and the amount of time spent on the operation would potentially not be worth it. This method could potentially be combined with other technologies making it possible to perform entire P&A operations without rig from monohull/RLWI vessels.

For the challenge of verifying cement behind multiple casings this has been addressed previously in this thesis and will not be repeated here. For dealing with the control lines outside the production tubing this is a challenge for P&A and several clever minds are attempting to come up with solutions that could solve this issue. These methods include cutting both tubing and control lines, cutting sections of it to allow for full cross-section barriers, cutting and pushing the debris down with a mechanical plug that can further be used as base for barrier to mention some. Several of these technologies are already designed to be run on wireline/CT so the challenge lies with potentially adapting them to be run with the OWCT system to place as many of the P&A operations on one vessel as possible. Alternatively, have a vessel which can deploy tools on both wireline and OWCT.

In addition the OWCT system in itself has its limitation as all systems do to ensure the safety of all personnel and equipment involved in the operation. There will be limitations with respect to vessel motions, operational window and due to the design of the system.

One limitation with the design is that the tool string length cannot be longer than the length of the lubricator section/tube. This is to ensure that the valves in the lubricator are able to close around the toolstring if necessary to control the pressure.

Another challenge is to apply optimum top tension to the CT string. Both too much and too little tension will have a negative effect on the CT string. Currently, there are no regulations which set a value for the top tension in the string but it should be as low as possible, at the same time ensuring positive effective tension in the entire CT string throughout operations.

Other known challenges with applying Coiled Tubing from a monohull vessel has been handling of equipment and the risk for personnel and handling of return with barriers in place in addition to fatigue. Fatigue is an issue for all CT systems (both with and without riser) due to the continuous reeling of the coiled tubing. The CT will be exposed to cyclic loading and it requires close monitoring to evaluate the remaining lifespan after each run. For an OWCT one will experience the “usual” fatigue over the gooseneck, which today's CT system to a large degree have optimized, but in addition an OWCT will experience fatigue when moving in and out of the injectors which keeps the CT in constant tension between vessel and subsea injector. This provides an additional challenge with regards to monitoring and controlling CT life span.

Island Offshore claims that they have overcome these challenges and are ready to use Coiled Tubing on a monohull RLWI vessel, provided that they can obtain finances from a customer/investor to test and qualify it on a live well.

5.4.4 Alternatives to cement as barrier

Previously this thesis has described some alternatives to cement including using formation, ThermaSet and Sandaband in addition to a completely new solution being developed by Interwell which utilises the materials already placed within the wellbore.

As discussed under section 5.1.4 one of the biggest issues with using alternative materials/methods is a reluctance in the industry towards changing something that works, in addition to the uncertainties in relation to the integrity of the materials in an eternal perspective.

According to the developers both Sandaband and ThermaSet has been verified to meet the requirements outline in NORSOK D-010 and their properties give them some clear benefits compared to the cement traditionally used.

The first alternative presented was Sandaband. The main benefit of this material is its Bingham-plastic properties which ensures that it can adapt to different conditions over time in the wellbore once its positioned. As described the material will not fracture but rather act as a fluid and reshape when exposed to shear stresses beyond the yield stress. This property is very important for P&A purposes as the conditions in a wellbore will change over time as natural processes run their course.

The other material presented was ThermaSet. This material has mechanical properties that highly outrange cement which result in it having better integrity for long-term purposes. As mentioned, the biggest obstruction for new materials are that cement has been in play for decades resulting in hesitation to implement other materials, even if they have better mechanical properties. Another issue is that cement is cheaper than the alternatives. However, with respect to long-term integrity and that it is operators' responsibility that wells are abandoned in a manner that ensures no future damage to the environment, the higher cost should be justified. If a well need to re-establish barriers this is a huge extra cost for operators. Based on this it should be in the operators' interest to test these materials, and others, in the field and over time establish experience and sufficient records for them to hopefully become the preferred solutions. As discussed earlier, there should also be issued a Norwegian guideline on alternative materials and how to qualify them similar to the UK Material guidelines, with Sandaband and ThermaSet included. Development of such a standard would make it easier to both encourage future developments and provide a recipe that developers can follow when investigating alternatives.

5.4.5 Interwell solution

As described this is a method that is in the qualification process by testing it in onshore pilot wells. The goal of the method is to melt the in-situ material located in a wellbore and thus creating a permanent barrier when the melt solidifies. According to Interwell, the results are promising although they are still adjusting the technology. If this technology can be proven to be safe, cost-efficient and reliable in a long-term perspective it is a potential game-changer in the P&A field. Restoring the cap-rock is the idea behind any permanent barriers and this method seem to be imitating and going beyond the original conditions by creating a solid that potentially is stronger than the original formations.

If the technology lives up to the expectations it would mean that the use of rig is eliminated, there would be limited need for removal of downhole equipment as most of it can be melted into a permanent barrier, and time consumed on each well would be drastically reduced resulting in significant cost-savings provided the method itself can be performed in a relatively cheap manner.

According to Interwell representative the biggest challenge for the technology is to fit the method within current regulatory framework and creating sufficient track record. Both these challenges have been addressed under different heading in this thesis. The current revision of NORSOK D-010 does not provide good directions on how to qualify alternative materials and methods nor does it seem to be encouraging the development of alternatives. With respect to generating sufficient track record this can be linked to the general hesitation within the industry towards implementing new and “uncertain” solutions.

As stated repeatedly in this thesis, the requirements should be altered to better take new methods/materials into consideration by e.g. eliminating the strict requirements to length and number of barrier and rather resort to a more risk-based perspective on these matters. This would potentially ease the challenge Interwell, and others, experience with respect to regulatory framework and make it easier to sell the idea to operators.

5.5 Eliminating the use of rig in P&A operations

One of the highest potential cost savers for P&A operations is eliminating the need for rig in P&A operations, and thus this has been focused throughout this thesis. The industry is attempting to develop solutions which can move operations from semi-submersibles to simpler vessels like the cat. A vessel, or modified versions of this. The main issues for using simpler vessels are that they are with current technology not capable of performing heavy operations like pulling of tubing and control lines, and there are still some gaps that need to be filled before these vessels will be the preferred solution on live wells. Currently the LWI vessel with riser can operate on live wells and circulate cement with CT, however the technology is not fully developed and thus it becomes an issue of weighting lower cost vessel with higher risk against more expensive vessels (semi-submersible) with low risk.

It might be an idea to have vessels which are dedicated to P&A operations. These vessels should be a compromise between the current vessels used in offshore operations making it able to perform some of the heavier operations while maintaining a cost-level which is significant lower than current cat. C vessels. It should incorporate ongoing development within P&A tools and methods making it a vessel for the future. As such, the vessel should preferably be designed with input from several of the companies in the industry. For the most complex subsea wells, eliminating the use of semi-sub might not be possible.

There are several issues that need to be resolved before a dedicated P&A vessel can become a reality and compete with the current preferred solutions. These issues include, but are not limited to, the following:

- The regulatory framework may need to be changed to allow for vessels to handle return flow from wells.
- Proper compensation of vessel motions, in particular heave motion.
- Qualification of safe ways to handle high pressure hydrocarbons combined with low pressure on deck.
- Placement of permanent barriers far down in wellbores. Some potential technologies have been presented with this in mind including the OWCT system and Interwell solution.
- Pulling of tubing and casing when this is necessary is a big challenge as this involves heavy lifting. Solutions to this issue could be further development of PWC to be valid for more than two casings, or the gas lift technology briefly mentioned previously.
- If tubing needs to be pulled, an additional problem might be deck space for the pulled tubing. A solution to this could be to have a separate vessel for storing the pulled material.

- Proper well control throughout operations when not using a riser.
- Being able to perform batch operations without the need to go back to shore for demobilization.

6 Conclusions and recommendations

This thesis has aimed to outline the current requirements to P&A found on the NCS and the UKCS and identify differences that exist within the regulations. The differences along with possible reasons to why they exist have been discussed, in addition to proposing improvements that potentially could make P&A operations on the NCS more cost-effective. As part of this some challenges and technological advances to handle these has been described and discussed. In this chapter, the proposed potential improvements to Norsok D-010 will be summarized based on the discussions in chapter 5.

6.1 General

After reading the regulations and investigating the ongoing technological development it is uplifting and clear that the challenges related to P&A are higher on the agenda in the industry. The field has been neglected for years due to the need not being present. However, now there is a plug wave approaching and efforts have been put into dealing with this in the best possible manner. Many clever minds are working on improving and challenging current practices. Still, there should be more research put into developing innovative solutions and cooperation within the industry to make P&A more cost-effective.

6.2 Recommendations for Norsok D-010

In the current revisions the Norsok and UK guideline are becoming more similar and thus the differences in requirements are reduced. However, there are still some possible improvements that could be made to Norsok D-010 and they are as follows:

- Separate abandonment activities from Norsok D-010 in an own standard, like they have in the UK. This should be done because the field is becoming increasingly important and it differs from other well integrity issues covered in Norsok D-010 (other has pressure control equipment as BOP etc).
- Make the P&A standard more suggestive and comprehensive rather than the prescriptive and definite style it has now.
- Rewrite the standard to better allow for alternative technologies to fit within the framework.
- Remove strict wording like the term *shall*. Instead, the term *should* should be more used as it is more suggestive and present an alternative. This encourages companies to follow best

practice and does not put the same limits on implementing potential new methods/technologies which does not fit within the exact framework of the standard.

- Remove the term *eternal* as it in reality presents a near impossible demand. The ramifications of a failed barrier are clear to all operators and they will install barriers with a very long-term perspective regardless. A better wording could be the *foreseeable future* term used in UK guidelines and in DNV GL.
- Do more research on well barrier length. The existing requirements seems to be empirically decided and emphasis should be put on finding what height is actually needed for maintaining barrier integrity. This should be done for both internal and external plug, and for when formation is used as barrier.
- Develop a material qualification guideline as part of NORSOK which is updated regularly and encompasses the newest advancement within P&A materials. The UK material guideline could be used as basis and it should be developed by experienced representatives of the industry.
- Verification of cement in the annulus. Alternatives to logging for verifying the sealing ability in casing cement should be developed for situations where logging is difficult or are not conclusive.
- Issue a document that presents novel methods and technologies within P&A operations with the aim of encouraging operators, and others, to develop and implement alternatives to the established practises. Such a document should be updated regularly (~every year) and describe the current best practices.
- A categorization system similar to the one found in UK guidelines should be developed to better get an overview of well status and work scope for operations. Such a system should be used in relations to developing a cost estimation guideline.
- Develop cost estimation as part of NORSOK which provides basis for a common industry approach to the process. Could be based on the UK cost guideline and should be developed by professionals within both economics and engineering to provide realistic methodologies.
- Incorporate a risk-based approach similar to the DNV GL-RP-E103. That every well is unique and thus may not require the same type, number should be recognized to a larger degree. A risk based approach may also account for uncertainties in a better way than the prescriptive method found in NORSOK D-010.
- Put more emphasis on the initial well design and future P&A. Have a plan for how and where to place permanent barriers in the future.

6.3 Recommendations for technology and methods

That technological advancements are the best solution for making P&A operations more cost-effective and optimum have been mentioned several times throughout this thesis. Some new and alternative technological solutions have been presented in relation to overcoming known challenges. This section will summarize what was learned and give recommendations on how the industry should proceed.

- The technologies should be further developed – operators should “take a chance” on new methods and aid developers in qualifying new technologies like OWCT and Interwell rig-less P&A solution.
- Eliminate section milling. A good alternative is to use PWC as standard operation whenever possible, at least until something “better” might be ready for the market such as the Interwell solution.
- Identify and test ways of pulling tubing without the use of rig, the gas-lift technique presented is one alternative.
- Test alternative materials to cement for use in permanent barriers with the aim of finding more suitable solutions. Two materials with properties superior to cement was presented, although these are not the only options.
- Eliminate the need for rig by developing technologies that can be run from LWI vessels such as gas injection for pulling tubing, OWCT and Interwell solution.
- Develop vessels and support that can perform full P&A operations on subsea wells while reducing the complexity of the operations. These should be able to perform batch operations without having to go to shore.
- Cooperation across companies, while ensuring ownership is maintained, to potentially combine some of the solutions.

References

1. Norwegian Petroleum Directorate. *6000 brønner på norsk sokkel*. 2017 [cited 2017 May 29]; Available from: <http://www.npd.no/no/Nyheter/Nyheter/2017/6000-bronner-pa-norsk-sokkel/>.
2. Norwegian Petroleum Directorate, *Exploration and Development wellbores*. 2017: Norwegian Petroleum Directorate Factpages.
3. Lasseigne, B., B.J. Lindsey, and J. Larke, *Performing Riserless Subsea Operations Utilizing Coiled Tubing in Open Water*. 2015, Society of Petroleum Engineers.
4. Noble, M. *Vessel-Based Suspended Well Abandonment*. in *3rd Norwegian Plug and Abandonment Seminare*. 2013. Stavanger: Norsk Olje og Gass.
5. Fjaertoft, L. and G. Sonstabo, *Success From Subsea Riserless Well Interventions*. 2011, Society of Petroleum Engineers.
6. Standards Norway, *NORSOK D-010, Well integrity in drilling and well operations*. Rev. 4, 2013, Standard Online AS: www.standard.no.
7. Straume, M. *Plug and Abandonment Forum*. in *Plug and Abandonment Seminar 2013*. 2013. Norsk Olje og Gass.
8. Valdal, M.B.L., *Plug and abandonment operations performed riserless using a light well intervention vessel*. 2013, University of Stavanger, Norway.
9. Oil and Gas UK, *Decommissioning Insight 2016*. 2016: Oil and Gas UK.
10. Kielland, C. *New DNV GL Guideline could save the oil and gas industry more than USD 32 billion*. 2015 16 June 2015 [cited 2017 10 April]; Available from: <https://www.dnvgl.com/news/new-dnv-gl-guideline-could-save-the-oil-and-gas-industry-more-than-usd-32-billion-27950>.
11. Weltzin, T. *Statfjor A PP&A*. in *Plug and Abandonment seminar 2012*. 2012. Stavanger.
12. Ringe, T., *Section milling during plug and abandonment of petroleum wells*. 2015, University of Stavanger, Norway.
13. Abshire, L.W., et al., *Offshore permanent well abandonment*. *Oilfield Review*, 2012. **24**(1): p. 42-50.
14. Ferg, T.E., et al., *Novel Approach to More Effective Plug and Abandonment Cementing Techniques*. 2011, Society of Petroleum Engineers.
15. Gundersen, J., *Well Integrity with focus on P&A*, Petroleum Safety Authority Norway, Editor. 2012.
16. GL, D., *Qualification of new technology*, in *Technology Qualification Process*. 2011, Det Norske Veritas: www.dnv.com.
17. Halliburton, *Saving rig time during plugging and abandonment*. 2013.
18. HydraWell, *The HydraWash system*. 2015.
19. Larsen, A.G., *E-mail correspondance*. 2017: E-mail.
20. Carlsen, T., *Formation as barrier during P&A*. 2012, Presented at Plug and Abandonment Seminar, Stavanger, Norway, June 2012.
21. Grannes, I., *Non-consolidating Plugging Material for Wellbore and Annulus*. 2011, Presented at Plug and Abandonment Seminar, Stavanger, Norway, June 2011.
22. Saasen, A., et al., *Permanent abandonment of a North Sea well using unconsolidated Well-Plugging material*. *SPE Drilling & Completion*, 2011. **26**(03): p. 371-375.
23. WellCem. *ThermaSet*. 2017; Available from: <http://www.wellcem.no/product-solutions>.
24. Beharie, C., *ThermaSet - An alternative plugging material*, S. Presented at Plug and Abandonment Seminar, Norway, June 2012., Editor. 2012.
25. Sandaband. *What is Sandaband*. 2017 [cited 2017 May 28]; Available from: <http://www.sandaband.com/modules/m02/article.aspx?CatId=56&ArtId=6>.
26. Tinne, B.M., *Plugging and Abandonment - Tubing retrieval on wireline or coiled tubing*. 2013, Norsk Olje og Gass.

27. Interwell, *The Superior P&A solution*. 2017, Interwell: Interwell.com.
28. Hauan, T., *Interwell e-mail correspondance*. 2017: e-mail.
29. Skjold, M., *Method of well operation*. 2013, Google Patents.
30. Offshore, I., *Next step for Island Offshore - riserless heavy well intervention*. 2016.
31. Valdal, M.B.L., *Plug and abandonment operations performed riserless using a light well intervention vessel*. 2013, M.B.L Valdal: Stavanger.
32. Opsanger, N.K., *Subsea live well intervention using a riserless/open water coiled tubing system- System overview and operational weather limitations*. 2016, University of Stavanger, Norway.
33. Offshore, I., *Riserless Coil Tubing for Plug and Abandonment, Subsea Wells*, in *Subsea Riserless CT Panda*. 2016, Norsk Olje og Gass
34. Oil and Gas UK, *Guidelines for the Abandonment of Wells*. 2015, Oil and Gas UK: Oil and Gas UK.
35. Oil and Gas UK, *Guidelines on Qualification of Materials for the Abandonment of Wells*. 2015, Oil and Gas UK: oilandgasuk.co.uk.
36. *The Offshore Installations and Wells (Design and Construction, etc) Regulations*. 1996.
37. Oil and Gas UK, *Guidelines on Well Abandonment Cost Estimation*. 2015, Oil and Gas UK.
38. Janbu, A.F., *Cutting well P&A costs by using DNV GL's new Recommended Practice*. 2016, DNV GL: dnvgl.com.
39. GL, D., *DNV GL-RP-103, Risk-based abandonment of offshore wells*. 2016, DNV GL: dnvgl.com.

Appendix

Appendix A: Verification of single permanent barrier – UK Guidelines for the abandonment of wells

Single permanent barrier (Primary and Secondary)				
Barrier type	Verification			
	Wellbore/tubing		Casing Annulus	
	Position	Sealing capability	Position	Sealing capability
Through tubing	Tag	Pressure test	Good cement bond, minimum 100ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 and 8.10 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
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	Good cement bond, minimum 100ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 and 8.10 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Cased hole	Tag	Pressure test	Good cement bond, minimum 100ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Cased hole on a mechanical barrier	Tag cement, or measure volume to confirm depth of firm barrier, subject to risk assessment	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 100ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Open hoke	Tag	N/A	N/A	N/A

Appendix B: Verification of permanent combination barrier – UK Guidelines for the abandonment of wells

Permanent combination barrier				
Barrier type	Verification			
	Wellbore/tubing		Casing Annulus	
	Position	Sealing capability	Position	Sealing capability
Through tubing	Tag	Pressure test	Good cement bond, minimum 200ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 and 8.10 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Through tubing on a mechanical barrier	Tag	Pressure test of mechanical barrier after release and pressure test cement in tubing and annulus separately	Good cement bond, minimum 200ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 and 8.10 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Cased hole	Tag	Pressure test	Good cement bond, minimum 200ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Cased hole on a mechanical barrier	Tag cement	Pressure test of cement barrier or mechanical barrier after release	Good cement bond, minimum 200ft, if previously logged or 1000ft above base of barrier if estimated from differential pressures	Refer to section 7.2 in UK guidelines ~ section on verification of permanent barrier (4.2.5) in this thesis
Open hoke	Tag	N/A	N/A	N/A

Appendix C: Listing of generic input needed for risk-based P&A – DNV GL-RP-E103

	Detail	Notes
General	Well details	number, field and location of wells type of well (production/injection) future usage plans for the well
	Field architecture	Subsea or platform, high level description
	Water depth	Water depth
Reservoir and overburden	Number of flow potential overburden formations	any formation which contains moveable fluids in the form of hydrocarbons or abnormally pressured water.
	Hydrocarbon-bearing formation 1	name & geological formation
		true vertical depth [TVD] range (top & bottom)
		contents of formation, including composition of hydrocarbons and volume capacity
	Additional hydrocarbon-bearing Formations	name & geological Formation, TVD range (top & bottom), contents formation, including hydrocarbon composition volume original, current and future pressures, cross-flow potential
	Subsurface factors	hydrogen sulphide [H ₂ S], carbon dioxide [CO ₂], geological faults, pore-and fracture gradients
Geological barrier formations	Formations that are or can be qualified as barrier	
Wellbore	Well history summary	Well barrier diagram and schematic
		Annuli fluids and annuli operating limits
		Primary well barrier status including status of tubular/casing/liner
		Secondary well barrier status including status of casing/cement including cement quality
		Previous abandonment activities, including side-tracks
		Wellbore stability diagrams, temperature plots, mud logs, pressure tests, open hole logs
		Challenges during well construction – caving, losses, washouts, cementing problems, borehole instability issues/geological challenges
		known well integrity issues – leaks, degraded components pressure containment issues
	Current and previous well operational status	well status details including the well’s operational mode and whether the well has additional equipment, for example, gas-lift.
Well flow assurance history	Wax, sand, hydrate and scale issues	
Site specific	Metocean data	Ocean current including salinity and temperature profiles
	Environmental resource overview	Uniqueness, rarity or importance of environmental resources of special importance for life-history stages of species
	Site specific safety	General or site-specific safety requirements

Appendix D: Generic well barrier failure modes for P&A wells – DNV GL-RP-E103

	Potential failure mode	Potential cause mechanism	Risk management strategy
Mainbore	Insufficient barrier length in mainbore	<ul style="list-style-type: none"> – low top of barrier – barrier slippage – density miscalculation 	include functional barrier length assessments into quantitative models
	Barrier function degraded in mainbore	<ul style="list-style-type: none"> – incorrect barrier density – operational issues – permeable barrier – high barrier shrinkage leads to increased porosity and stresses that may cause a microannulus to form 	perform sensitivity studies as to the flow potential through and around these barriers
Casing	Corrosion of casing	<ul style="list-style-type: none"> – well fluids exposure or long-term exposure 	perform sensitivity studies as to the flow potential through and around these barriers Include formation aspects and time perspectives
	Yielding of casing due to pressure in well	<ul style="list-style-type: none"> – well loading over time including geological forces – formation loads 	
Annulus	Insufficient barrier length in annulus	<ul style="list-style-type: none"> – slippage due to inadequate density or losses – not able to perform squeeze job 	include functional barrier length assessments into quantitative models with sensitivity studies
	Degradation of annulus barrier	<ul style="list-style-type: none"> – channelling/lack of bonding – CO₂ corrosion – H₂S corrosion – magnesium chloride degradation – thermal cracking and/or de-bonding (microannulus) due to Joule-Thomson effect during injection into, e.g., depleted gas reservoir – pre-existing channels – pre-existing micro-annulus 	perform sensitivity studies as to the flow potential through and around these barriers
	Contamination of annulus barrier	<ul style="list-style-type: none"> – poor mud and filter cake removal leaves a route for hydrocarbons to flow up the annulus – high barrier shrinkage leads to increased porosity and stresses that may cause a microannulus to form 	
Formation	Overpressure of formation	<ul style="list-style-type: none"> – build-up of pressure over time – injection nearby 	evaluate the formation characteristics, the need for crossflow prevention and natural leakage/seepage
	Fluid exposure	<ul style="list-style-type: none"> – degradation effects over time 	
	Geological barrier formation	<ul style="list-style-type: none"> – potential to use formations as an additional well barrier, if possible 	identify if compacting formations or aquifers can be used as permanent barriers.