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Christer Halvorsen

Abstract

In the North Sea, the average field age is increasing and a large number of wells needs to be plugged and abandoned in the future. P&A is regarded as an operation with no financial returns and is associated with significantly high costs. With a continuous increase in the number of wells that require abandonment and a falling oil price, the major focus for the oil industry is reducing costs while ensuring safe and reliable plugging of wells.

The conventional method for placing a plug in a cased hole with no external barrier has required section milling of the casing, underreaming the open hole, and placing a balanced cement plug. The conventional method is time-consuming and costly, and is associated with several challenges and risks concerning Health, Safety and Environment (HSE). To reduce the cost and increase the efficiency of P&A operations, more attention has been directed towards the subject of P&A in recent years.

This thesis has examined and presented the conventional section milling technology along with its limitations and challenges, and compared it with new technology's with respect to time and scope. The main focus has been the new perforate, wash and cement (PWC) technology developed by HydraWell, and its advancement in the P&A operation. A case study comparing the conventional section milling operation with the PWC operation has been performed. Other investigated alternatives include reverse/upward section milling and plasma-based milling.

This thesis also gives an insight into the process of plugging a well, including regulations and requirements, plugging materials, placement techniques, cement evaluation tools and challenges with the P&A process.

The main findings revealed that most of the challenges with the section milling operation can be led back to the generated swarf. The case study revealed that the installation of the reservoir and secondary barrier was the most time-consuming part of the P&A operation. It also revealed that by applying the PCW technology, the operational time used to install the reservoir and secondary barrier could potentially be reduced by 73 % compared to the section milling operation. Considering the impressive scope ahead, the PWC technology has potential to reduce cost significantly for operating companies and national authorities in the future.

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List of Abbreviations

ASV	-	Annulus Safety Valve
BHA	-	Bottom Hole Assembly
BOP	-	Blow Out Preventer
CBL	-	Cement Bond Log
EAC	-	Element Acceptance Criteria
ECD	-	Equivalent Circulating Density
HSE	-	Health, Safety and Environment
JIP	-	Joint Industry Project
LOT	-	Leak Off Test
N/D	-	Nipple Down
N/U	-	Nipple Up
NCS	-	Norwegian Continental Self
NORSOK	-	Norsk Sokkels Konkurranseposisjon
		(Competitive Standing of the Norwegian Offshore Sector)
NPD	-	Norwegian Petroleum Directorate
OBM	-	Oil Based Mud
P&A	-	Plug and Abandonment
POOH	-	Pulled Out of Hole
PSA	-	Petroleum Safety Authority
PWC	-	Perforate, Wash and Cement
RIH	-	Run in Hole
ROP	-	Rate of Penetration
RPM	-	Revolutions per Minute
SPF	-	Shots per Foot
TCP	-	Tubing-Conveyed Perorating
TOC	-	Top of Cement
USIT	-	Ultra Sonic Image Tool
VDL	-	Variable Density Log

WBE	-	Well Barrier Element
WBM	-	Water Based Mud
WBS	-	Well Barrier Schematic
WH	-	Wellhead
WL	-	Wireline
WOB	-	Wait on Bit
WOC	-	Wait on Cement
XLOT	-	Extended Leak-Off Test
XMT	-	Xmas-Tree

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1 Introduction

The life of a well comprises several phases. The phase that no one seems to enjoy facing is the final phase of the wells lifecycle. When the production has fallen and the operating expense is higher than the operating income, the well will be plugged and abandoned. The well can be temporarily abandoned, permanently plugged and abandoned, or the well can be re-used by permanently abandon the bottom of the well and performing a slot recovery.

In the North Sea, the average field age is increasing and there is a large number of wells to be plugged and abandoned in the future. P&A is generally not a straight forward operation and introduces several challenges. Documentation of wells drilled decades ago can be incomplete or missing, and the well status unknown. Also, as P&A was not included in the initial well design in the past, the abandonment design and execution can be challenging.

Well abandonment was in the past done quickly and with minimal expense as it was, and still is, considered as a nonrevenue operation. However, due to environmental issues, changes in the regulatory climate have caused operators to change their attitude. Regulations require that the well shall be plugged over the entire cross-section and to seal the wellbore for eternity. This have to be done to meet the objective to prevent free flow of pore fluids to surface and control subsurface pressures to protect the environment.

The Norwegian NORSOK D-010 standard states that a permanent barrier should be placed at a depth interval where the casing is well cemented and the formation outside has sufficient integrity. A sufficient length of good cement is however not always available and remedial actions have to be made.

The conventional method to create a competent barrier when the casing cement is insufficient is either to cut and pull the casing from the wellbore or mill away the casing. It is not always possible to pull the casing as it can be stuck, due to old cement and settled particles in the annulus. A section milling operation is then required to gain access to the formation. Conventional section milling is however considered time-consuming and costly, and causes several risks concerning Health, Safety and Environment (HSE).

During the last years, more attention has been directed towards the subject of P&A. The rising cost have provided motivation for change in the technology and methods used to do the work.

In this thesis work, the conventional section milling operation along with its challenges will be presented. A new perforate, wash and cement (PWC) method introduced by HydraWell will also be presented. This method is engineered to eliminate many of the problems associated with conventional section milling and is expected to be less time-consuming. An evaluation of time-consumption of this two methods are presented in a field case study. New technologies to permanently abandon wells is also included within in this thesis work.

1.1 Background

Since the first offshore well was drilled in 1966 and until today (13.06.16), 5886 wells have been drilled on the Norwegian continental shelf (NCS). Out of these wells are 4286 developments wells and 1600 exploration wells (1). There are no exact statistics at NPD`s fact page as of today about the amount of wells to be permanently plugged on the NCS. But, a study performed by (2) showed that as per 28.02.2015 were the total amount of 2552 wellbores to be plugged and abandoned on the NCS. At the time was 5768 wellbores drilled on the NCS. This does however not include the amount of new wells that will be drilled in the future.

According to Statoil ASA, the average P&A operation on the NCS took 16 days to complete in the period of 2000-2004. The average duration suddenly increased to 35 days in the period of 2004-2010 (3), as shown in figure 1. There are probably several factors influencing the sudden increase, but an interesting fact is that NORSOK D-010 rev. 3 was published in august 2004. This underlines that regulations and standards are major drivers for the whole P&A process.

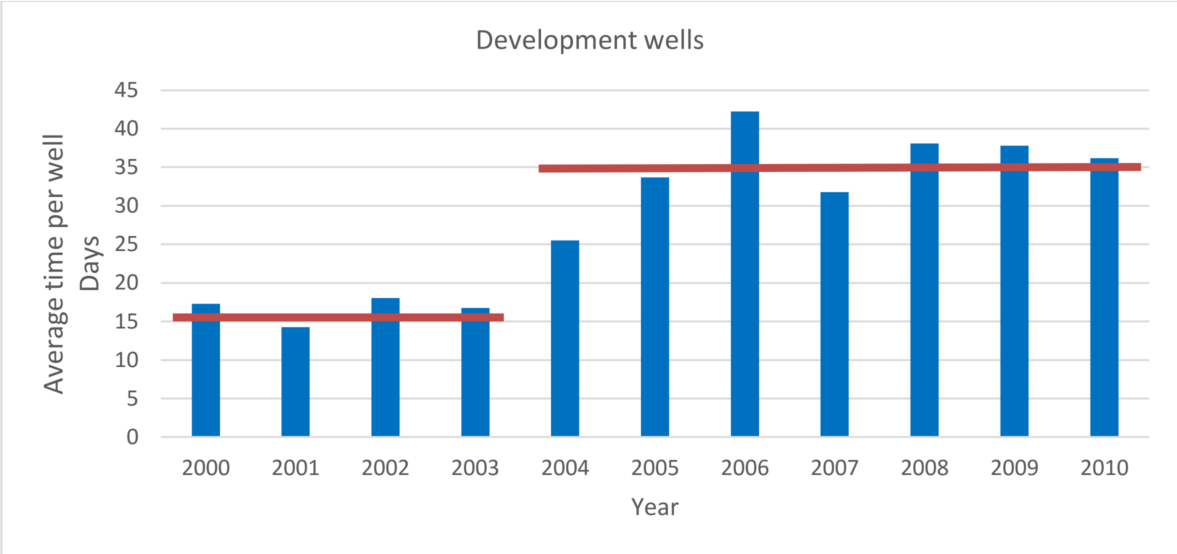


Figure 1 – Average operational time of P&A per well (3)

The example in table 1 illustrates how time-consuming permanent plugging operations will be on the NCS if conventional technology is used.

Table 1 – Estimate of time spent on P&A at the NCS in the future

Average time per well	35 days
1 rig will P&A 10 wells per year	350 days
15 rigs will yearly P&A	150 wells
Time to P&A 2552 wells	**17 years**
New development wells drilled each year	114 wells
New development wells in 17 years	2448 wells
Time to P&A 2448 at the same rate (150 wells/year)	**16,3 years**

This rough estimate shows that with the use of conventional technology, it will require the deployment of 15 rigs full-time to P&A the present and future wells over the next 36,3 years. Also, as time equals money, this time estimate is used to give a rough estimate of the total plugging cost on the NCS. Table 2 illustrates the total plugging cost.

Table 2 – Estimate of the total plugging cost at the NCS

Burn rate (rig rate + overhead) (4)		4,0 mill NOK/day
Yearly cost per rig	4,0 mill NOK x 365 days	1460 mill NOK
15 rigs	1460 mill NOK x 15 rigs	21 900 mill NOK
36,3 years	21 900 mill NOK x 36,3 years	**794 970 mill NOK / 795 billion NOK**

This estimate shows that the total plugging cost will be 795 billion Norwegian kroner. It is especially important to minimize the cost of permanent P&A in Norway as the state is obligated to fund 78 % of the cost, due to current tax regulations. Also, 78 % of the estimated cost is nearly equivalent to a tenth of the current value of Norway's sovereign wealth fund.

This means there is a strong financial motivation to push innovation in P&A forward. There are several challenges with the conventional P&A approached used today. The conventional section milling operation is time consuming and requires to be improved to be more efficient or it has to be replaced by new technologies. One way of reducing cost is by reducing the time-consumption. Improved and new technology has the potential to reduce the number of rig hours/days used for P&A, and can indirectly reduce cost.

With the impressive scope ahead several challenges need to be faced and solved in the near future. For P&A to be economically sustainable for operating companies and national authorities, new technologies, new procedures and new solutions are of crucial importance to be developed in the near future.

1.2 Scope and Objective

The primary objective of this thesis work is to investigate the conventional section milling technology along with its limitations and challenges, and compare it with new technology's with respect to time and scope. The activities are:

- Literature study on P&A regulations and requirements
- Literature study on plugging materials
- Include a general P&A procedure to give an understanding of the whole P&A operation
- Literature study on conventional technologies and new technologies
- Present a field case study on time-consumption of P&A operations performed with conventional technology vs new technology
- Investigate P&A challenges

Figure 2 displays a summary of the research methods.

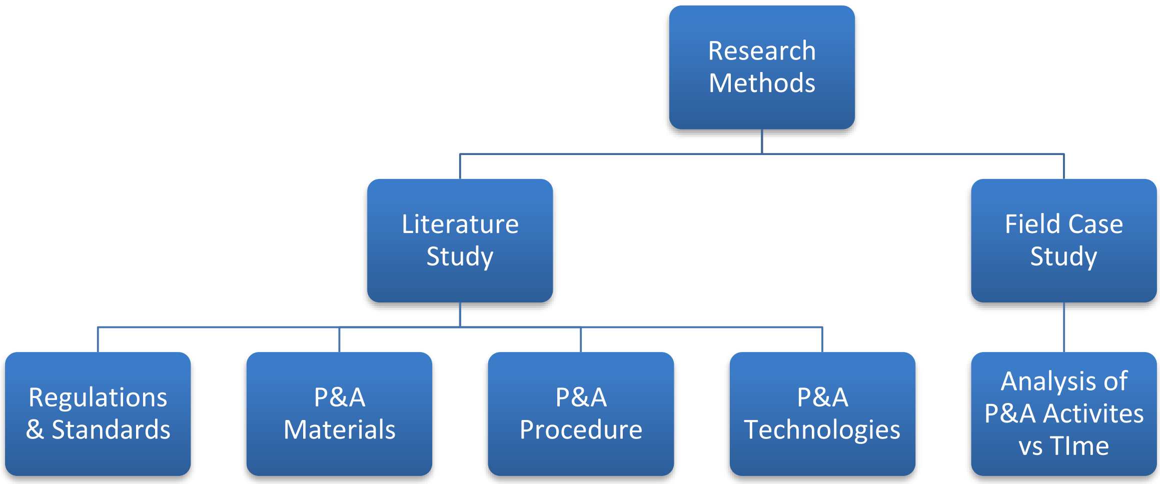


Figure 2 – Research methods

2 Definition of Plug and Abandonment

All oil and gas wells will at some point in their lifecycle be plugged and abandoned. The decision to plug and abandon a well is severely based on economics, but can also be necessary it there are problems that cannot be repaired.

P&A is a well operation where the well is sealed off and secured with one or more well barrier elements (WBE). This is done with the objective to restore the natural integrity of the formation that was penetrated by the wellbore. P&A must be performed in a safe and proper way, and must be done in accordance with local regulations and requirements.

The well can be abandoned it two different ways, either temporary or permanently.

A well is temporary abandoned if the operator has intention to re-enter the well at a later stage. In such a case, the well control equipment is removed and the well is secured to prevent leaks. If the well is considered as not useful in the future, it shall be permanently plugged. NORSOK D-010 states that if the well barriers of a temporary abandoned well are continuously monitored, there is no maximum abandonment period. For wells without monitoring, the maximum abandonment period shall be three years (5).

Permanent abandonment is a well status where the whole well, or part of the well, will be plugged and abandoned permanently. In some situations, only the bottom of the well is permanently abandoned and the well will be re-used by doing a sidetrack. The upper section is used to perform a sidetrack to access a new target in the reservoir. This is considered as economically attractive as the top infrastructure and the well slot can be reused. This method is also known as slot recovery.

For instances when the reservoir is considered as no longer profitable and the well has fulfilled its purpose it will be permanently plugged and abandoned. Wells that are permanently plugged and abandoned will not be used or re-entered again. The focus of this thesis is permanent P&A.

3 Regulatory framework and regulations

Worldwide, different countries and regions operate with specific regulatory frameworks, regulations and requirements for well abandonment. The North Sea has some of the world's most stringent and well-defined regulations. Norway and the United Kingdom are the two major actors in the North Sea with long-established producing areas that contain mature fields and aging infrastructure that are ready to get plugged and abandoned. The law in these two countries holds the owner or last operating company as the responsible party to permanently plug and abandon the well to ensure that no fluids leaks from the well. Insufficient P&A operations pose risk to the environment and exact a toll on the reputation of the company. The responsible party is also bound to clean up and repair in case of any failure, but remedial plugging operations are difficult and expensive. Plugging a well correctly at the outset is far easier, even if the initial financial outlay appears high. Regulations have changed and been updated considerably over the years to facilitate P&A operations in a safe and proper way. As regulations is one of the major drivers for the whole P&A process they have a big impact on the P&A operation.

This thesis will first present the regulatory framework that controls the P&A activities in Norway, and then take a look into regulations designed for abandonment in the Norwegian sector of the North Sea.

3.1 Norwegian state organisation of petroleum activities (6)

The petroleum industry of Norway is well organized, with clearly defined areas of responsibility.

3.1.1 Stortinget (the Norwegian Parliament)

The formal head of petroleum activities in Norway is Stortinget. Stortinget determines the framework for petroleum activities, partly through its legislative authority. All fundamental principles, including major development projects must be considered and approved by Stortinget.

3.1.2 The Government

Executive authority lies within the Government, which is responsible for the petroleum policy and to answer the Storting in this regard. The Government is assisted in the role of implementing petroleum policy by the ministers, underlying directorates and supervisory authorities. The layout of this structure is presented in figure 3.

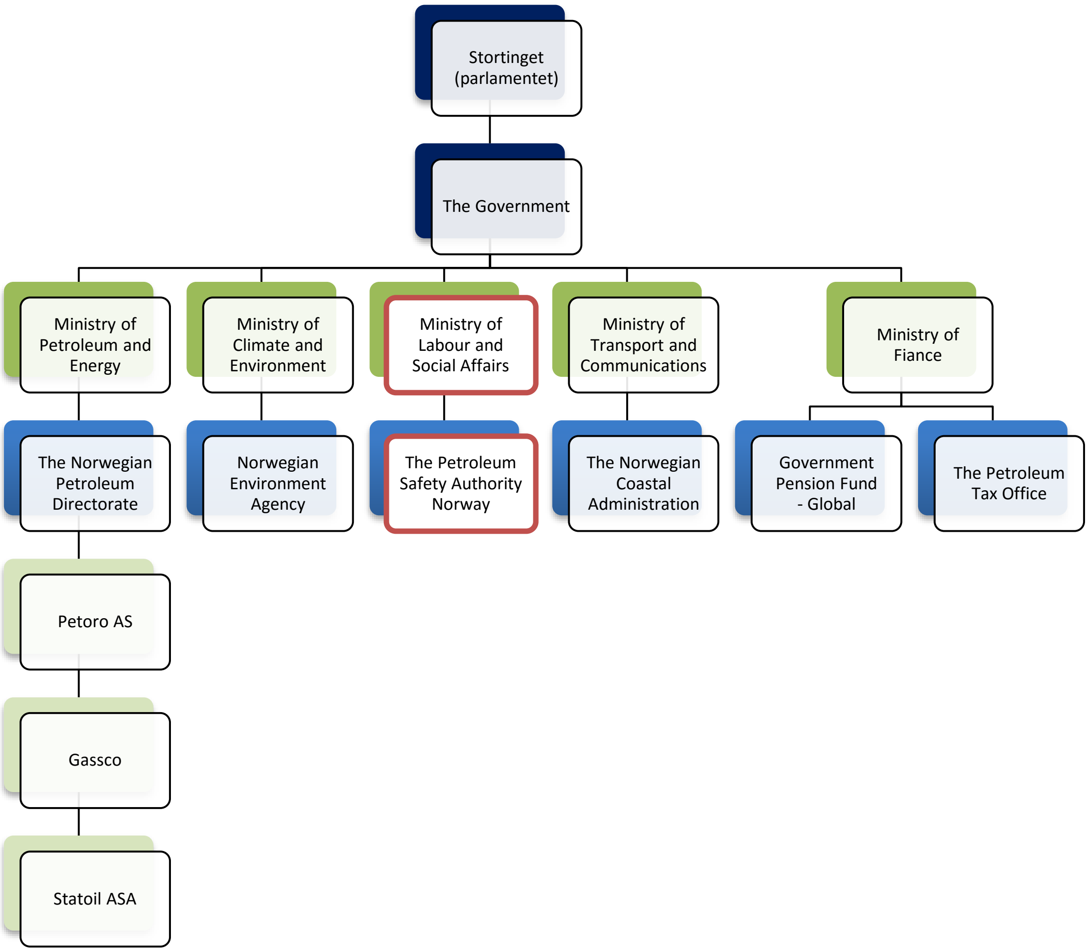


Figure 3 – Norwegian state organisation of petroleum activities (6)

3.1.3 The Ministry of labour and Social Affairs

The Ministry of Labour and Social Affairs has the overall responsibility for the working environment and for safety and emergency preparedness in the petroleum sector.

3.1.4 The Petroleum Safety Authority (PSA)

The Petroleum Safety Authority of Norway is a subordinate agency of the Ministry of Labour and Social Affairs.

The PSA is the regulatory body of Norway with responsibility for technical and operational safety, emergency preparedness, and the working environment throughout the petroleum activities.

The most central regulations for offshore petroleum activities are:

- The Framework HSE regulations
- The Management regulations
- The Facilities regulations
- The Activities regulations

The most important sections regarding P&A operations are stated in the facilities regulations and the activity regulations.

These regulations are generally formulated as functional requirements. This means they are performance-based and express the result (aspects, characteristics or qualities) which a product, process or service is to produce (7). This gives the responsible party the ability or freedom to choose a solution that fulfils these requirements, but it also gives them the full responsibility for being compliant with the requirements.

Regulations refers to recognized standards that provides solutions which fulfils the functional requirements in the regulations. The recommended standard provides one solution, and if the responsible party choose this solution the requirement in the regulation is considered fulfilled. PSA does however allow other solutions if they give a safety level just as good as or better than the recommended standard.

The NORSOK standards are some of the recommended standards which fulfil the functional requirements of the regulations.

3.2 The development of NORSOK - the Norwegian shelf's competitive position

In the 1990s, the oil industry in Norway experienced a rising cost of offshore development, while the price of oil was falling. The outlook for a considerable number of developments on the NCS were pessimistic, and therefore new initiatives were needed for the business to survive. As the oil industry provides a substantial income to the state of Norway, this was very much a political issue as well as an industrial matter.

To address the issue, the former Norwegian Minister of Industry and Energy, Mr. Finn Kristensen, established a Development and Production Forum for the petroleum industry in Norway. The goal of the forum was to improve the competitive standing of the Norwegian petroleum industry by identifying and implementing possible improvements. To achieve this, seven workgroups were launched within the forum, and one of these were to deal with standardization. (8)

When standardization work commenced, every petroleum company had its own set of standards which to a large degree were based on US originated standards such as standards from API, ASTM, ANSI etc. (9) Even though they were similar, they were different, and they were to some extend designed for other climate conditions than those encountered on the NCS. The large amount of standards made it difficult for suppliers who had to be aware of every companies' specific requirements, and could easily lead to confusion, prolonged deliveries and subsequently higher costs.

The solution became to develop a set of industry standards called NORSOK (the competitive standing of the Norwegian offshore sector) which would replace the individual oil company specifications and close the gap and shortcomings to the international standards. Standardization was considered as a key to achieve cost effectiveness, and according to Jacob Mehus (Managing director at Standards Norway), empirical data form the North Sea show up to 30-40 % savings on investments cost as a result of companies using standardized solutions instead of company specific solutions (10).

Today, Standards Norway facilitates petroleum standardization work by hundreds of Norwegian and foreign industry experts from operators, suppliers, service companies, the Petroleum Safety Authority and the maritime industry. Petroleum standardization in Norway is the product of voluntary tripartite cooperation with participants from employers' organizations, employee unions and the government.

There are currently about 79 national NORSOK standards in active use. NORSOK D-10 (Well Integrity in Drilling and Well Operations) is of specific interest for this thesis and will be discussed more in detail in the following chapter.

4 NORSOK D-010

The relevant NORSOK standard for this thesis is the NORSOK D-010 – Well Integrity in Drilling and Well Operations. The NORSOK D-010 should be used as a minimum standard in order to fulfil the functional requirements of the regulations. This standard defines the minimum functional and performance oriented requirements and guidelines for well design, planning, and execution of safe well operations. Operator develop their own sets of requirements and work processes that in minimum must follow NORSOK D-010.

NORSOK D-010 uses a terminology to distinguish between requirements and guidelines. *Shall* is a term used to indicate requirements that are strictly to be followed, and where no deviation is permitted, unless accepted by all involved parties. *Should* is a term used to indicate a solution that among several possibilities are recommended as particularly suitable, without mention or excluding others. This means *should* is used where a certain action is preferred, but not necessary required (5).

In 2013 revision number four of D-010 was released. Revision four is the standard currently in use, and it provides more information particularly regarding plugging and abandonment. The most central chapters regarding P&A are:

- Chap. 4.2 – Well barrier principles
- Chap. 9 – Requirements for sidetracks, suspension and abandonment operations
- Chap. 15 – well barrier acceptance criteria's for 50 Well Barrier Elements (WBE)

This chapter focus on the NORSOK D-010 standard, and starts off with descriptions of generic principles regarding well barriers.


NORSOK Standard
D-010
Rev. 4, June 2013

Well integrity in drilling and well operations

Figure 4 – NORSOK D-010 (5)

Well Integrity – a definition

First, it is important to understand the well integrity term. Well integrity is defined in NORSOK as: "*application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well."* (5)

The purpose of well integrity is to maintain full control of fluids within a well throughout all phases of the wells lifecycle, from designing the well to after the well has been permanently plugged and abandoned. For the P&A phase, well integrity during and after P&A includes barrier material, barrier placement and subsequent monitoring of the well to detect potential leaks.

4.1 Well Barriers

Well barriers are implemented to a well to maintain well integrity and prevent unwanted flow of formation fluids to surface or other formations while performing well operations or while the well is inactive or abandoned. A well barrier is defined by NORSOK D-010 as *"envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment"* (5). The same standard defines a well barrier element as: "*a physical element which in itself does not prevent flow but in combination with other WBE's forms a well barrier"* (5). Therefore, is it imperative that the well barrier elements can withstand the pressure exerted by the reservoir, and form an envelope enclosing the well to ensure its integrity. If one WBE leaks or fails, there should always be a backup barrier to ensure integrity.

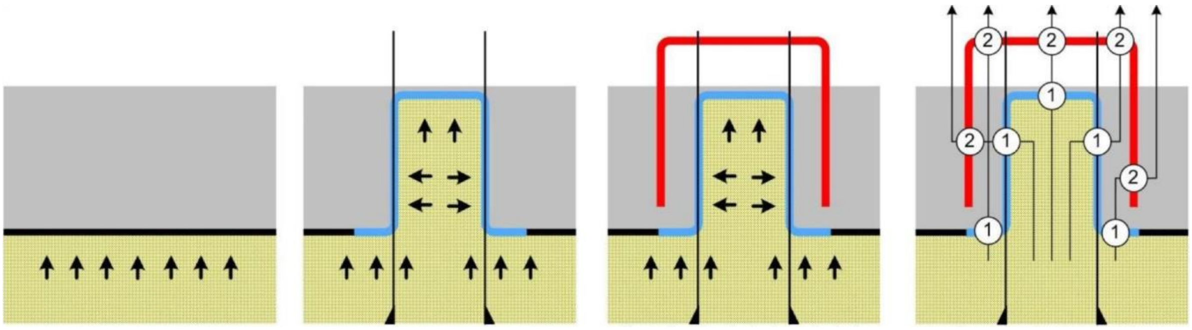
The well is normally operated with multiple barriers in an envelope, however there are cases where NORSOK D-010 only require one well barrier to be in place:

Table 3 – Minimum number of well barriers (5)

Minimum number of well barriers	Source of inflow
One well barrier	a) Undesirable cross flow between formation zones b) Normally pressured formation with no hydrocarbon and no potential to flow to surface c) Abnormally pressured hydrocarbon formation with no potential to flow to surface (e.g. tar formation without hydrocarbon vapour)
Two well barrier	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

When two well barriers shall be in place, NORSOK differentiate between primary and secondary well barriers. The first barrier envelope is the primary well barrier. This is the innermost barrier, closest to the potentially pressurized hydrocarbon zone and is the first well barrier that prevents flow from a potential source of inflow. The secondary barrier envelope is the secondary well barrier and is located outside the primary barrier envelope. The secondary well barrier is not necessarily the second defence in a sequence, but acts as a backup barrier or as a last line of defence if integrity of the primary well barrier is lost. The primary and secondary well barriers should be independent of each other and to the extent possible not have any common WBE’s. If a common WBE is present, a risk analysis shall be performed and risk reducing measures applied (5).

The advantage of using the envelope principle is that one can design two independent envelopes, one outside the other, like a “hat-over-hat” arrangement as seen in figure 5.



Pressure held in place by cap rock | Primary barrier containing pressure | Secondary independent of primary barrier | Secondary barrier providing redundancy for any situation.

Figure 5 – Barrier envelope – "hat-over-hat" arrangement (11)

4.2 Well Barrier Schematic

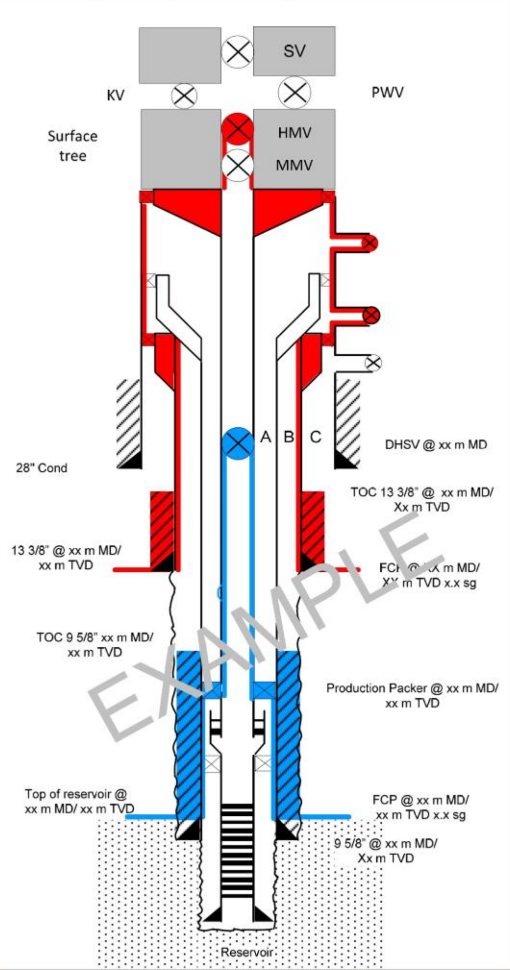
NORSOK states that "a well barrier schematics (WBS) shall be prepared for each well activity or operation (5)." WBSs is graphical illustrations of the well, showing the different WBSs that make up the well barrier envelope. The primary well barrier (envelope) is coloured in blue and describes the normal working stage. The secondary well barrier (envelope) is coloured in red and describes the ultimate working stage.

Regulations worldwide requires the use of WBSs, but operators are also mandating the use of WBSs as part of their internal requirements or best practices. The use of WBSs is not only driven by regulations requiring their use, but many operators sees the benefits of WBSs as a very practical method to convey to all stakeholders how they are safeguarding their wells.

When a well is ready to get plugged and abandoned information about the well status is vital. The WBSs will constitute as a key documentation element when the responsibility of the well is handed over from one party to another. The WBS offers a clear illustration of the well status and information about all stages of the well's life cycle.

Most operators have their own way of making WBSs which exceeds those seen in NORSOK. Figure 6 is an example of a WBS from NORSOK D-010.

Well information (as built)	
Field/Installation:	
Well name:	
Well type:	Producer
Well status:	Shut-in
Well design pressure:	xx bar
Revision number:	Version 1.0
Date prepared/revised:	
Prepared by: Verified/Approved by:	



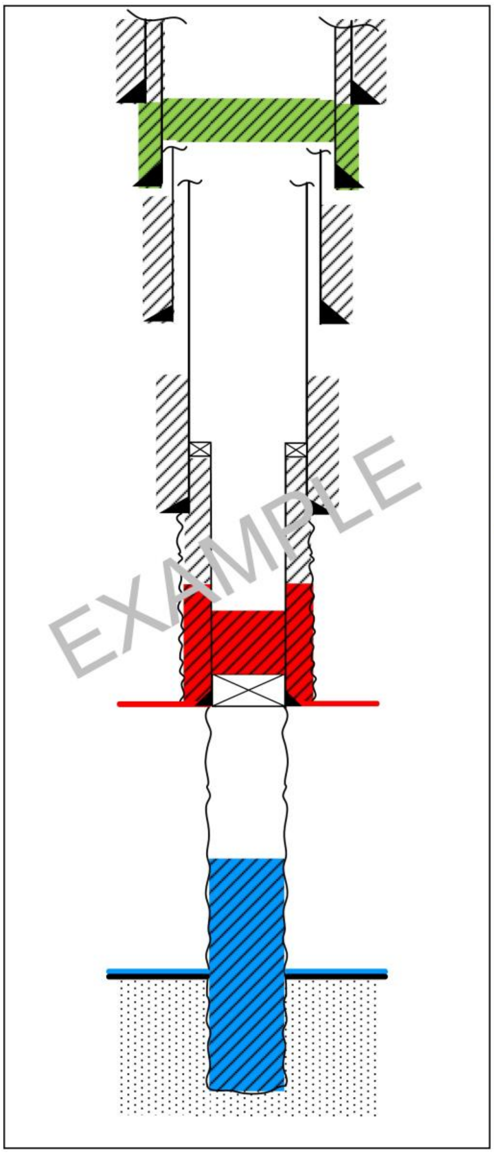
Note 1: Well shut-in due to tubing leak above DHSV.

Nomenclature:
PT: Pressure test
IT: Inflow test
FCP: fracture closure pressure
XLOT: extended leak off test
AC: acceptance criteria

Well barrier elements	EAC table	Verification / Monitoring
Primary well barrier		
In-situ formation (cap rock)	51	FCP: x.x s.g. Based on field model
		n/a after initial verification
Casing cement (9 5/8")	22	Length: xx mMD Cement bond logs
		Daily pressure monitoring of B-annulus
Casing (9 5/8")	2	PT: xx bar with x s.g. EMW
		n/a after initial verification
Production packer	7	PT: xx bar with x s.g. EMW
		Continuous pressure monitoring of A-annulus
Completion string	25	PT: xx bar with x s.g. EMW
		Continuous pressure monitoring of A-annulus See Note 1.
Completion string component (Chemical Injection valve)	29	PT: xx bar with x s.g. EMW
		Periodic leak testing AC DHSV: xx bar/xx min
Downhole safety valve (incl. control line)	8	IT: xx bar (DHSV) PT: xx bar (control line)
		Periodic leak testing AC DHSV: xx bar/xx min
Secondary well barrier		
In-situ formation (13 3/8" shoe)	51	FCP: x.x s.g. Based on XLOT
		n/a after initial verification
Casing cement (13 3/8")	22	Length: xx mMD Method: Volume control
		Daily pressure monitoring of C-annulus
Casing (13 3/8")	2	PT: xx bar with x s.g. EMW
		Daily pressure monitoring of C-annulus
Wellhead (Casing hanger with seal assembly)	5	PT: xx bar
		Daily pressure monitoring of C-annulus/ Periodic leak testing
Wellhead / annulus access valves	12	PT: xx bar
		Periodic leak testing of valve AC: xx bar/xx min.
Tubing hanger (body seals and neck seal)	10	PT: xx bar
		Periodic leak testing
Wellhead (WH/XT Connector)	5	PT: xx bar
		Periodic leak testing
Surface tree	33	PT: xx bar
		Periodic leak testing of valves AC: xx bar/xx min

Figure 6 – Example of WBS – Platform production/injection/observation well capable of flowing (5)

This thesis will focus on barriers that are set in place in order to secure the well for permanent plug and abandonment. When permanently abandoning a well is it usually not enough with two well barriers in place. Figure 7 is an illustration of a WBS of a permanent abandoned well. The additional green well barrier is an open hole to surface barrier and is the shallowest well barrier set to isolate the exposed open hole to the external environment.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Cement plug	24	
Secondary well barrier		
Formation in-situ	51	
Casing cement	22	
Casing	2	
Cement plug	24	
Open hole to surface well barrier		
Casing cement	22	
Casing	2	
Cement plug	24	

Figure 7 – Example of WBE – Permanent abandonment, open hole

4.3 Well Barrier Acceptance Criteria

In order to qualify the well barrier or WBE for its intended use, some technical and operational requirements need to be fulfilled, this is called well barrier acceptance criteria (WBAC).

The WBAC includes the number, function, position, material and verification of the well barrier. The WBAC table for a cement plug is included in the appendices.

4.4 Temporary Abandonment

This thesis focus is not temporary abandonment. NORSOK D-010 states however:

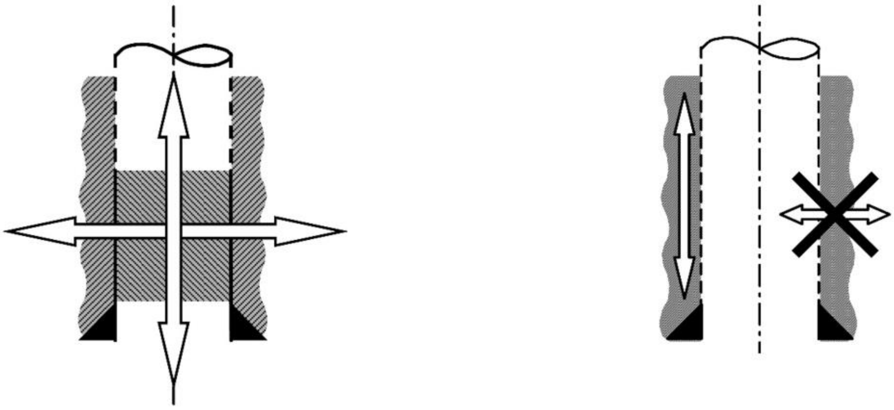
"Requirements for isolation of formations, fluids and pressures for temporary and permanent abandonment are the same. The choice of WBEs may be different to account for abandonment time, and ability to re-enter the well, or resume operations after temporary abandonment." (5)

4.5 Permanent Abandonment

NORSOK D-010 defines permanent abandonment as: *"as a well status, where the well is abandoned and will not be used or re-entered again* (5)*.*

NORSOK D-010 also states that *"permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented."* (5)

The function of a permanent well barrier is to seal off and isolate any source of inflow to avoid all leak paths in all directions. Hence, permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally. This implies that the well barrier element needs to be placed inside the casing at an interval where there is good sealing at the outside of the casing both in a horizontal and a vertical direction.



Well barrier extending across full cross section of well, sealing both vertically and horizontally

Cement in annulus alone is not accepted as a permanent WBE, because it is not sealing both vertically and horizontally across the full cross section of the well

Figure 8 – Well barrier element

4.6 Well Barrier Requirements

NORSOK D-010 states that every well barrier element used for plugging of wells shall withstand the load and environmental conditions they may be exposed to for the abandonment period.

The permanent barrier material needs to fulfil a number of functions to be able to withstand external and environmental loads, and variations in these, without losing its functionality. Likely loading conditions could be related to pressure, temperature, mechanical stresses, chemicals etc., and variations in these.

4.6.1 Material requirements

NORSOK D-010 defines seven characteristics that materials used for permanent well barrier should fulfil:

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.

These characteristics are not necessarily required but is recommended as particularly suitable for well barrier materials. As NORSOK D-010 defines the minimum functional requirements that the material should fulfil, it does not specify which material type that should be used. It does however state that elastomer seals are not accepted as components in WBE's for permanent abandonment.

4.6.2 Position requirements

The position of the well barrier is fundamental for its ability to achieve isolation.

According to NORSOK D-010 shall the base of both the primary and secondary well barrier be positioned at a depth where formation integrity is higher than potential pressure below.

Formation integrity is a collective term used to describe the strength of the formation. It is important to know the strength of the formation around the well in order to prevent that the formation will fracture when exposed to a pressure from below. This means that the formation at the base of the plug needs to withstand a potential internal pressure in order to not create fractures into the formation inducing possible leak paths with communication to surface. Information about the strength or fracture pressure of the formation is usually conducted during drilling operations with a leak-off test (LOT). A stricter requirement used by Statoil is to set the base of the barriers at a depth where the potential pressure below is less that the minimum formation stress. The minimum formation stress can be obtained from an extended leak-off test (XLOT), which is an extended version of a LOT.

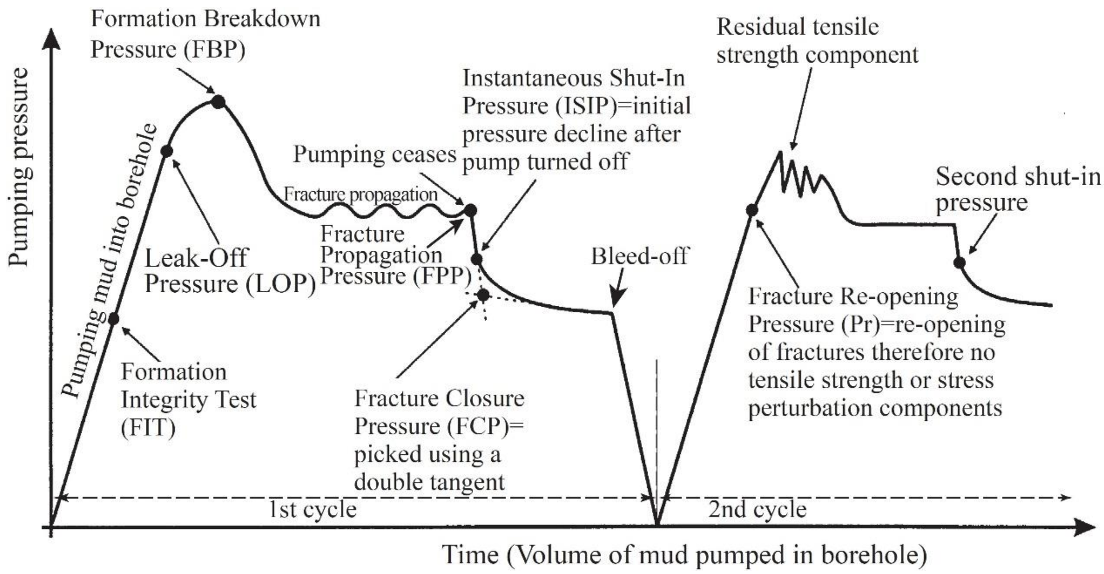


Figure 9 – XLOT pressure graph (12)

Leakoff tests are immediately carried out after drilling a few feet blow a new casing shoe. The well is shut-in during the test and mud is pumped with a constant pump rate into the wellbore to increase the pressure gradually. At some pressure, fluid begins to diffuse into the formation, or leak off. This is known as the leak-off pressure and is reached when the pressure increase and volume of mud pumped starts to deviate from linear (fig. 9). During an XLOT, pumping continues until the pump pressure reaches a peak value, known as the formation-breakdown pressure (FBP). This creates a new fracture beyond the near wellbore. Pumping is then continued to ensure stable fracture propagation into the formation and is stopped when the pressure stabilizes at a stable fracture propagation pressure (FPP). The pressure will then decline as a result of backflow of fluids and the newly created fractures will close again. This point is known as the fracture closure pressure (FCP) and represents the minimum principal stress in the formation. To confirm that stable values of the initial XLOT have been obtained, additional pressurization cycles is normally conducted.

Information about the minimum formation stress together with the potential internal pressure will be used to find the minimum setting depth. The potential internal pressure is based on the worst anticipated reservoir pressure and the lowest anticipated fluid density of the abandonment period. The potential internal pressure is then determined as the reservoir pressure minus the hydrostatic pressure of the fluid. Initial/virgin reservoir pressure can be used in the calculations, but redevelopment scenarios like water/gas injection or gas storage shall be accounted for.

According to NORSOK D-010 there is no depth requirement with respect to formation integrity for the open hole to surface well barrier. However, as an example, Statoil requires that the open hole to surface well barrier shall be positioned as deep as possible in the surface casing and with the top minimum 50 m above the shallowest permeable zone.

If the cement plug is placed on a mechanical plug NORSOK D-010 states, the following: *"The plug shall be set as close as possible to the source of inflow and set at a depth where the hydrostatic pressure above the plug balances the pressure under the plug." (WBAC table 28)*

4.6.3 Length Requirements

The length of the well barrier must be adequate to ensure sufficient strength and have ability to endure all loads it may be exposed to.

The length requirement of the internal well barriers (e.g. cement plug) depends on whether it is placed on a foundation or not, and if the casing cement can act as a permanent external WBE.

For the internal WBE, NORSOK D-010 states:

"An internal WBE (e.g. cement plug) shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and shall be minimum 50 m if set on a mechanical plug/cement as a foundation, otherwise according to EAC 24."

Even though NORSOK D-010 does not specify which material type that should be used in well barriers, the length requirements for internal WBE are mainly based on the WBEAC (table 24) for cement plugs. Table 24 describes the acceptance criteria for a cement and is quite comprehensive. Table 4 is an extraction from table 24, presenting the length requirements for a cement plug in different situations.

Table 4 – Length requirements (5)

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.

The internal WBE shall be positioned where there is a verified external WBE, as stated above. NORSOK D-010 requires that the external WBE (e.g. casing cement) shall be verified to ensure a vertical and horizontal seal. The requirement for an external WBE is either 50 m with formation integrity at the base of the interval or minimum 30 m interval of casing cement with acceptable bonding verified by logging. It is also required that the interval has formation integrity.

Verification of well barriers and logging methods are covered in section 4.7 and chapter 5 respectively.

4.6.4 Number of Well Barriers

NORSOK D-010 requires that there shall be at least one permanent well barrier between the surface and a potential source of inflow. Minimum one well barrier is required if the formation have no potential to flow to surface and/or if there is undesirable cross flow between zones (table 4). A source of inflow is defined as *"a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water* (5)*."* It is important to note that hydrocarbons normally are movable, unless they are residual or have extremely high viscosity.

NORSOK requires minimum two well barriers if the formation contains hydrocarbons or is abnormally pressurized with potential to flow to surface (table 4). Abnormal pressure is if the formation or zones of the formation have a pore pressure above the normal (regional) hydrostatic pressure.

When permanently plugging and abandoning a well, minimum two well barriers shall be installed to seal off a potential source of inflow. Minimum one primary well barrier and one secondary well barrier. In addition, an open hole to surface well barrier shall be installed to isolate the exposed formation(s) to surface after casings(s) are cut and retrieved. Crossflow well barriers shall be installed to prevent flow between formations when crossflow it is not acceptable. The crossflow well barrier may also function as a primary well barrier for the reservoir below.

Multiple reservoir zones/perforations located within the same pressure regime can be regarded as one reservoir for which a primary and secondary well barrier shall be installed (5).

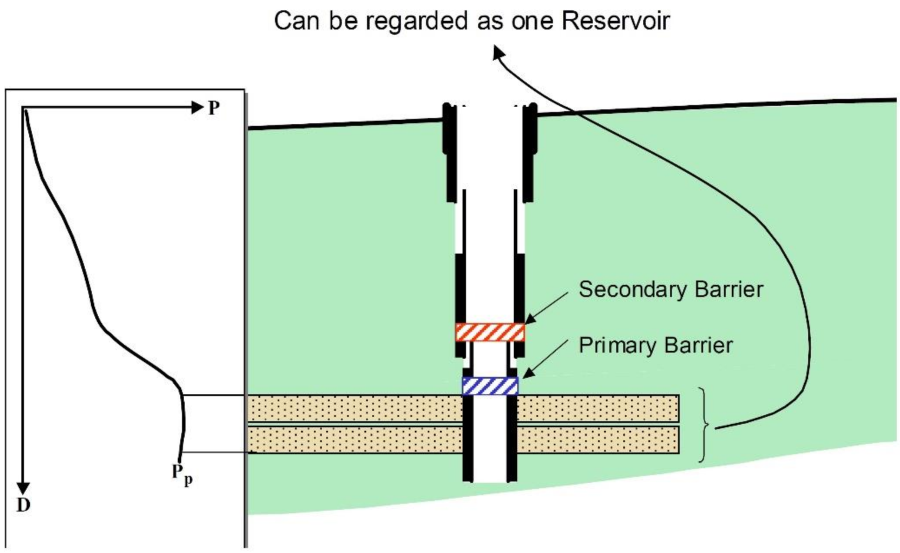


Figure 10 – Multiple reservoirs within the same pressure regime (5).

4.7 Verification of Well Barriers

All newly installed WBEs must be verified to ensure well integrity. Even though the placement of the well barriers is not the most complicated process of an P&A operation, it is vital to make sure that the well barrier is placed at required depth and that it have the required properties to seal the well for eternity.

In NORSOK D-010 section 4.2.3.5 it is stated that when a WBE has been installed, its integrity shall:

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

Well barrier elements that require activation shall be function tested. A re-verification should be performed if:

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

4.7.1 Internal WBE

All barriers placed in a well must be vertified to ensure that the barrier is placed at the required depth and that the barrier element have the required seling capability.

The WBE must be able to witstand a differential pressure, $\Delta P = P_1 - P_2$., where P_1 is the potential pressure below the WBE and P_2 is the pressure above the WBE.

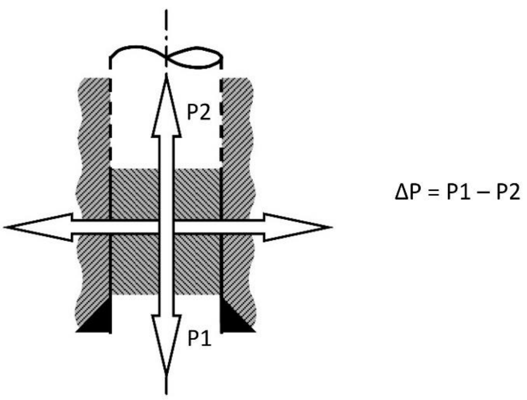


Figure 11 – Verification of well barrier element

NORSOK D-010 states that the pressure test direction should be applied in the direction of flow towards the external environment. But as long as the WBE is constructed to seal in both flow directions, the test can be performed against the direction of flow. Two different types of pressure test are described below.

NORSOK D-010 also states that the acceptable leak rate for a WBE is zero, but other can be specified in EAC`s. *"For practical purposes acceptance criteria should be established to allow for volume, temperature effects, air entrapment and media compressibility. For situations where the leak-rate cannot be monitored or measured, the criteria for maximum allowable pressure leak (stable reading) shall be established."* (5)

It should be noted that if a WBE, e.g. a cement plug, is set on a pressure tested foundation, pressure testing the cement barrier will not be meaningful and is therefore not required. It shall however be verified by tagging.

4.7.1.1 Inflow/Negative pressure Test

The inflow or negative pressure test is designed to test the mechanical integrity of the WBE and to verify that the WBE is isolating in the direction of flow. The test is performed by reducing the hydrostatic pressure above the WBE, $P_1 > P_2$. This is either done by displacing the well to an underbalanced fluid or by bleeding off the shut in pressure. According to NORSOK D-010 the test should last for a minimum of 30 minutes with stable readings to be approved. The test should be longer if large volumes, high compressibility fluids, or temperature effects are present. The pressure is monitored during the test to check for any increase in pressure. An increase in pressure indicates that the WBE is leaking, while stable readings indicates that the WBE is sealing under the current conditions.

This kind of test can also be performed during other drilling and well activates, such as completion, well testing, deep water disconnects, drilling out of casing below a permeable high pressure zone, etc. (5)

4.7.1.2 Positive Pressure Test

A positive pressure test is performed against the direction of flow, by creating a differential pressure across the WBE, $P_1 < P_2$. The test is performed by pressuring the well up to a certain pressure after the WBE has set. A positive pressure test can either be performed as a low pressure test or a high pressure test. The low pressure test is set to 15-20 bar and have to be stable for a minimum of 5 minutes. The pressure values for the high pressure test is set to be equal to, or higher than the maximum pressure that the WBE may be exposed to. The pressure is monitored during the test and stable pressure readings shall be observed for a minimum of 10 minutes for the test to be approved. (5)

4.7.1.3 Tag Top of Cement (TOC) & Load Test

To verify that the WBE is placed at the required depth it is of interest to tag the TOC. This is performed by lowering the workstring or toolstring slowly until the string lands on the WBE and a reduction in the weight is noticed. The WBE is then tagged and the location is confirmed.

A load test can be performed to test the integrity of the WBE. The load test is often performed in the same operation as tagging TOC. When the worksting is lowered onto the TOC, weight is applied onto the workstring. If the workstring stays constant in position while more weight is applied, the plug is solid, has set, and is approved. If the workstring changes position, the cement plug is insufficient or of bad quality. In some cases, the uppermost part of the cement plug is of bad quality due to contamination from mixing with other fluids. It might be necessary to “dress off” the plug at the top before conducting the load test. Also, if the cement has not got enough time to set, it can be soft and the load test will give insufficient results. In such a case, it could be beneficial to wait and perform a new load test, before concluding that the cement plug is of bad quality.

4.7.2 External WBE

The annular or external WBE shall also be verified to ensure a vertical and horizontal seal. NORSOK D-010 states that if casing cement is verified by logging, a minimum of 30 m interval with acceptable bonding is required to be approved as a permanent external WBE. It is also stated that the same interval shall have formation integrity. Evaluation of annular WBE is covered in chapter 5, where the two main types of logs, Cement Bond Log (CBL) and ultrasonic Image tool (USIT) are presented. Also the use of shale as annular WBE is presented.

It is also often of interest to verify the position of TOC of the annular cement. This can be done by the CBL or by temperature logs, or on the basis of track records for the cement operation. The temperature log is not covered in this thesis.

5 Evaluation of annual barrier prior to P&A

One of the most important operations performed during the completion of a new well is the primary cementing job. The primary cementing job involves the process of pumping cement into the annulus between the casing and formation to place a continuous cement sheath around the casing. The main functions of the cement are to bond and support the casing, provide zonal isolation across various permeable zones and the wellbore, and protect the casing from corrosive fluids.

The cement sheath is considered to be one of the most important barrier elements in the well, both during production and after well abandonment (13). The quality of the primary cement job depends on factors as the quality of mud displacement, cement design, shear bond strengths between the pipe-cement and cement-formation, temperature estimation, formations fluids etc. The long term isolation of the cement sheath is however the hardest property to achieve. Loss of cement integrity can first of all be caused by an unsuccessful primary cement job, but it is also well known that the cement sheath can fail over time due to chemical degradation or repeated mechanical or thermal stresses.

This can generate cracks, microannuli, debonding from casing or formation, or other defects. Such defects will most likely drastically increase the effective permeability of the cement sheath, and create leak paths in the structure. If continuous leak paths are created in the cement sheath, zonal isolation is lost. Loss of zonal isolation is one of the main causes of pressure build-up and leakages in ageing wells.

As described in section 4.5, the permanent well barrier shall extend across the full cross section of the well and include all annuli. This implies that if good quality cement is present in the annulus, the cement can be considered as a permanent external barrier and a cement plug can be set inside the casing to create a seal across the full cross section of the well. However, as described, the quality of the annular seal can be poor and it can even be totally absent. Evaluation of the annular barrier is therefore necessary to be performed.

It is important to obtain information about the exact location of the seal, including quality, level of bonding, presence of cracks, pockets and channels, and distinguish between the barrier material and the formation.

An easy but crude way of estimating the location of the seal is by evaluating the displacement calculations from the primary cement job. This is done on the basis of track records from the primary cement operation showing the amount of fluid flow returns to surface, compared to the volumes pumped and the volume of space between the casing and the formation. Although this can provide an indication on where the TOC is, this method can be quite inaccurate due to uncertainty of the annular volume between the casing and the formation, leading to false volume calculations. In addition, this method does not provide information about the quality and sealing capacity of the WBE.

Logging can be used as a better option to determine the presence and integrity of the annular cement. The two main tools used to check the bonding and integrity of the annular cement is the Cement Bond Log (CBL) and the Ultra Sonic Image Tool (USIT). Both these logs will be described in the following sections.

The results and interpretation of the logging will drive and support the process to decide a relevant P&A strategy. If a minimal length of good cement in the annulus is not existing, the conventional solution has either been to cut and pull casing-strings to surface or by milling a section of the casing to place a cement plug against the formation. Conventional methods for P&A are covered in chapter 10. Another new method called perforate, wash and cement (PWC) is presented in chapter 11.

5.1 Cement Bond Log (CBL)

Conventional CBL tools compromises a transmitter and a pair of receivers spaced at 3 and 5 feet from the transmitter. The transmitter is pulsed to produce a low frequency (10-20 kHz) omni-directional acoustic signal that travels along various paths through the borehole fluid, pipe, cement, and formation. The signals that are reflected back will be picked up by the receivers. The amplitude, wave type, and travel time of the received signals will be processed to provide information about the materials behind the casing.

The amplitude of the first arrival picked up by the 3-ft. spaced receiver will give information about the cement bond to casing as the acoustic signal has travelled through the pipe, but not through the cement and formation. The 5-ft. receiver process a “total energy wave” and is presented in the form of a variable density log (VDL) or microseismogram (MSG) (14). These logs provide information about the amplitude of the signal across the total acoustical waveform and is used to get a qualitative indication of the cement bond between the cement and formation.

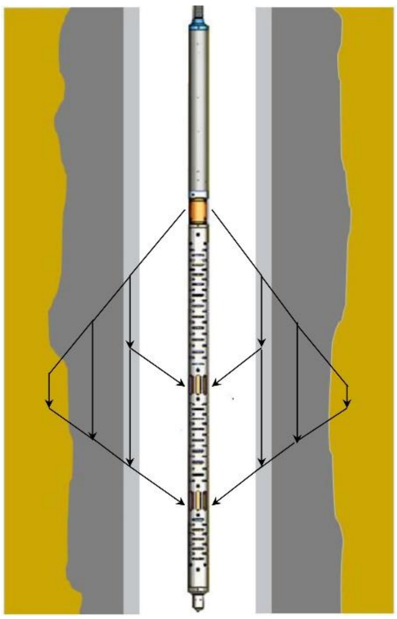


Figure 12 – CBL tool with one transmitter and two receivers (14)

The classical interpretation of the amplitude measurement is that low amplitude and longer transit time corresponds to good cement bond, while high amplitude and shorter transit time corresponds to free pipe or no cement bond. Basic interpretation of the waveform display is that straight traces indicate no cement in the borehole, while any variations in the acoustical waveform indicates that some cement is present. Figure 13 and 14 provides standard logs from the same well with the waveform in the more recent microseismogram form and the actual waveform.

Figure 13, is a good example of a well with free pipe section. The high amplitude readings in track 4 together with the typical straight vertical lines of the microseismogram in track 3 in indications of free pipe.

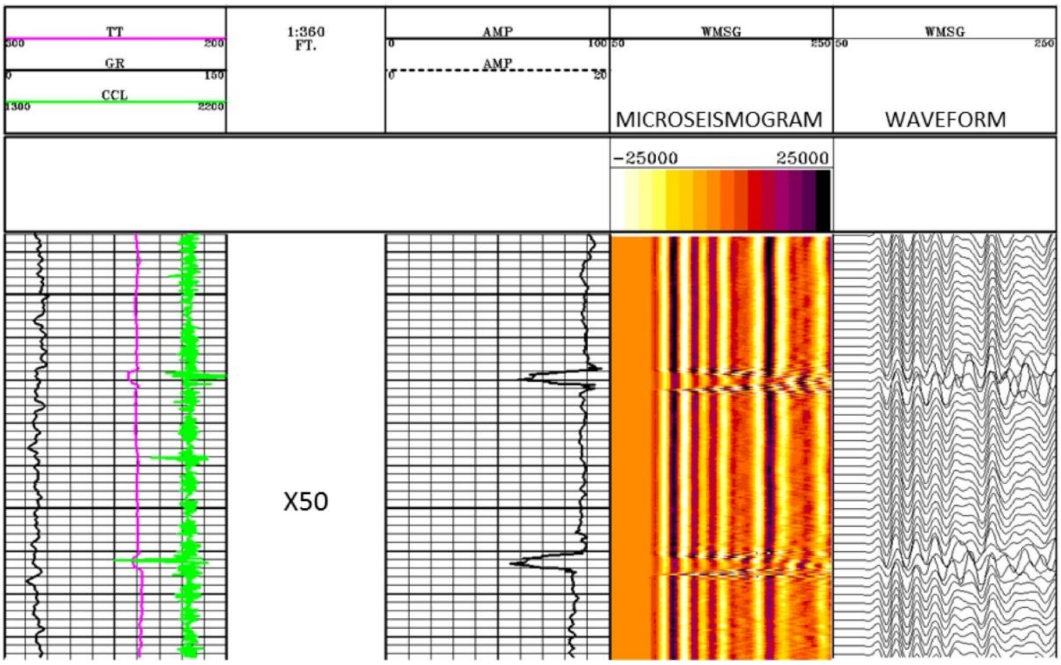


Figure 13 – CBL of free pipe section (14)

Figure 14, on the other hand is a good example of a bonded section. Notice that the log response is completely different. The waveform in track 3 is damped and the amplitude in track 4 is low until the end where some formation response is picked up.

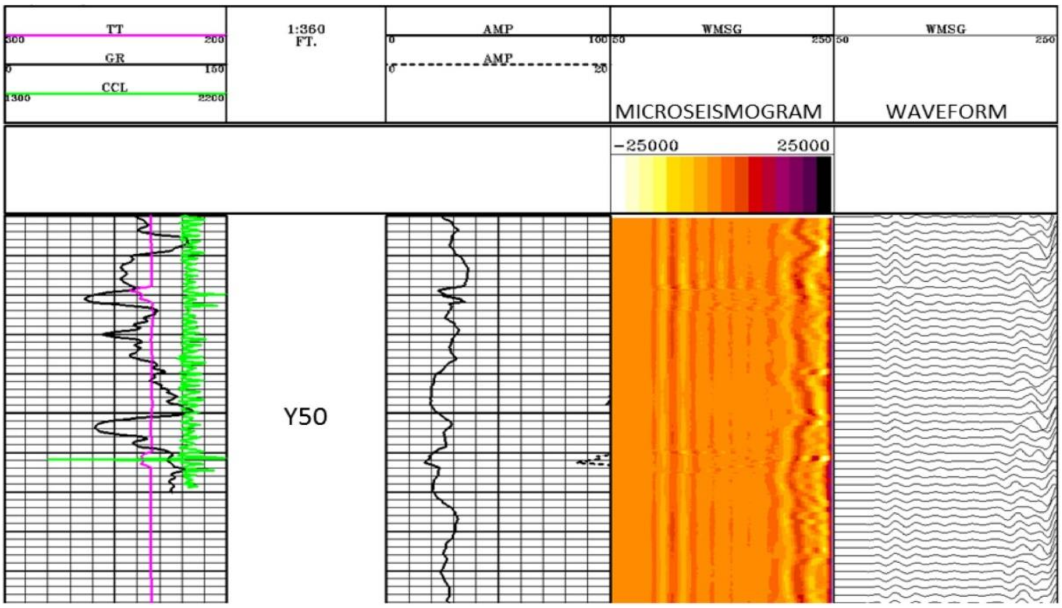


Figure 14 – CBL of bonded pipe section (14)

There are however some weaknesses of the standard CBL tool. First of all, the interpretation of the CBL waveform requires an experienced eye as it can be difficult to interpret. Second of all, the basic waveform cannot determine or confirm pressure or fluid isolation of zones. The tool averages around the wellbore, assuming that the cement strength is uniform throughout the interval and that the cement thickness is consistent. Due to this averaging of the wellbore, determining isolation in short intervals may be subjected to errors as possible microannuli and channels cannot be seen on the log. To determine isolation over intervals less than approximately 50 ft. increases the risk (16). However, as long as there are sections of continuous channel-free cement, isolation of the zone should be adequate. Cement isolation can however be determined by the use of ultrasonic logging tools.

5.2 Ultrasonic Logging

Instead of a separate source and receiver, the ultrasonic source and receiver are manufactured together as a transducer (14). The ultrasonic scanning or imagining acoustic tool use a single rotating ultrasonic transducer that emits ultrasonic pulses with frequency in the range of 250 kHz to 700 kHz (18). The ultrasonic pulses travel through liquid (mud) and into the casing wall where most of the wave energy is reflected. Some energy is transmitted through the casing wall and will hit the boundary between the casing and cement. Again, some energy is reflected, while some energy continues further into the annulus where it will continue to bounce back and forth as new interfaces are emerged. The fractional amounts of reflected and transmitted energy depend on the acoustic impedances of the materials behind the interface.

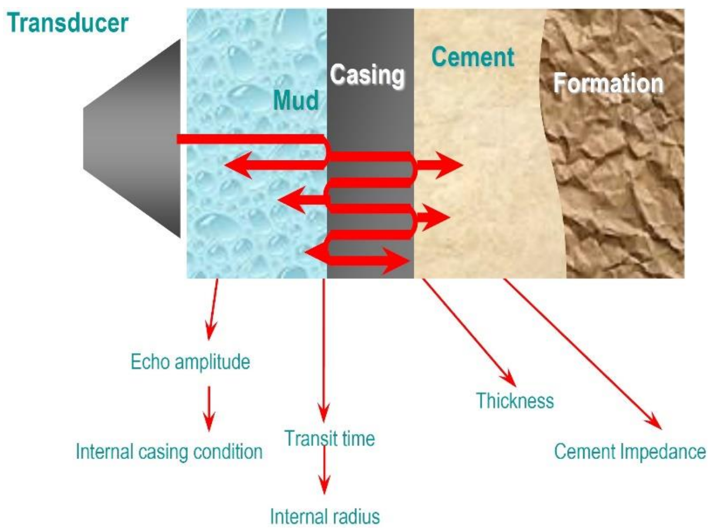


Figure 15 – Ultrasonic measurement (19)

The travel time of the first large signal form the initial reflection can be used to calculate the internal radius of the pipe to check if the tool was eccentric. The time separation between the next signals can be used to calculate the casing thickness, as the transit time in the casing can be establish. The reflected waveforms provide information about the impedance of the annular material behind the casing. Thresholds set for the acoustic impedance boundaries between materials expected behind the casing are then used to yield information about the material behind the casing. High impedance indicates good and dense cement behind the casing, while low impedance indicates less dense cement, no cement or that fluids may be present.

Since the tool is rotating, several measurements are made on each revolution, providing a full radial coverage of the casing circumference. Due to this the ultrasonic logs has better vertical and azimuthal resolution compared to CBL logs. This also make it possible to detect channels and their orientation.

The ultrasonic image tool will create an image log/map that will display the distribution of the materials presented behind the casing. This log/map is colour coded according to the values of the impedance which is measured in MRayl units. According to the impedance, the material is classified as gas if the value is less than 0.3 MRayl, liquied between 0.3 and 2.6 MRayl, or solid if higher than 2.6 MRayl (18). The acoustic impedance of the cement can be determined, and the quality of the annular cement can be identified.

It should be noted that the ultrasonic logging tool is sensitive to high mud weights inside the casing, and therefore is it usually a maximum mud weigh limit for utilizing this tool. Also as this tool does not provide any information about the cement formation interface, it is useful to use the ultrasonic tool and the CBL for cement evaluation.

Log results from a well in the Chinarevskoe filed is shown as an example in figure 16. Log results from an ultrasonic logging tool, shown in trach 6, shows that the cement is of good quality across most of the interval except a few places where liquid channels are present in the cement. Brown colours indicates that the annulus has 100 % azimuthal coverage with cement, while the blue stripe pattern indicate that channels filled with liquid is present in the cement sheaths.

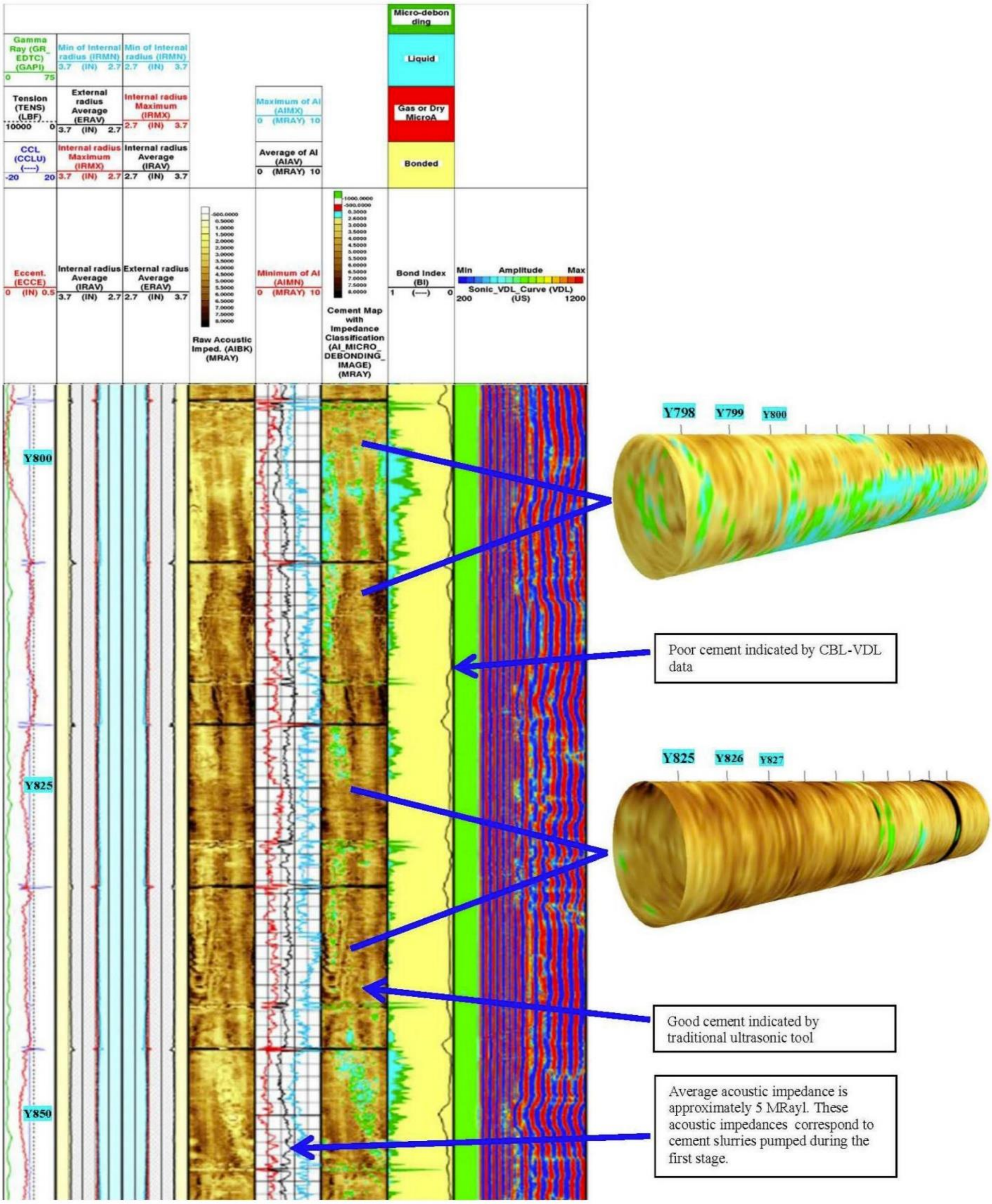


Figure 16 – Traditional ultrasonic tool data. Images are not orientated (20)

5.3 Identification of shale as annular barrier (18)

During interpretation of CBL/USIT logs to evaluate annular cement, intervals of log response indicating good cement bonding have commonly been observed far above the theoretical top of cement. This kind of response can only occur if solid material is present and hard packed onto the outside surface of the casing. Also during drilling, and after drilling, it is commonly observed that certain formations begins to move inwards and close off the well. This phenomenon is normally considered undesirable during drilling and casing running, but can be desirable when plugging as it can be used as an annular barrier behind casing.

There is good correlation between zones showing good bonding on CBL/USIT logs and clay rich zones recognized from cutting analysis during drilling and measurement while drilling (MWD) logs. This indicates that the solid material outside the casing which is showing good bond response is shale formation which have collapsed and squeezed onto the casing.

This kind of formation is common in the Tertiary and Cretaceous shale in all parts of the NCS. The displacement mechanism causing the shale to close the annulus completely is most likely due to plastic creep caused by overburden pressure. Shear and tensile failure could also be a contributing factor to initiate the process. Mud weights higher then pore pressure is often required to keep shale sequences stable while drilling. After the casing is set, a reduction of the density of the mud behind casing will occur. This can cause stresses which exceeds the strength of the shale, resulting in shear and tensile failure. Other factors as thermal deformation due to temperature differences during production, pressure effects near wellbore, and shale-brine interactions may enhance creep, but is not believed to contribute significantly to the displacement mechanism.

It is important to understand the displacement mechanism, as this has implication whether the shale is suitable to preserve its properties to act as an annular barrier or not. But in order for the shale formation to be used as an annular barrier it must have certain physical properties, and it must be uniform around the full circumference of the casing over a sufficiently long interval along the well. It must have sufficient strength to withstand the maximum expected pressure it may be exposed to and have extremely low permeability to fluids.

In order to determine the position and the extend of the shale formation, two independent logging tools shall be run, for example the CBL and USIT which is explained in the sections above. Also to ascertain that the observed annular barrier is real and that it has sufficient strength, the formation should be pressure tested to be qualified as an annular barrier. One way of performing such a test could be by perforating at the base of the potential barrier and then apply a pressure until either a pressure response is seen at the casing annulus at surface, or a leak-off pressure is seen.

Log graphic from a P&A program were a 9 5/8 casing where logged to verify the formation to casing bond in a Shetland clay are shown in figure 17. The log graphic includes CBL/VDL logs and ultrasonic logs over a representative interval in the Shetland clay. The ultrasonic log indicates well bonded material with high impedance all around the annulus. This is supported by the CBL and VDL logs, with low amplitude on the CBL, and clear dampening on the VDL. Three liquid filled layers of Shetland chalk are present in the interval, but the shale is well bonded above and below. A pressure test was also conducted subsequent to the logging, confirming the annular barrier.

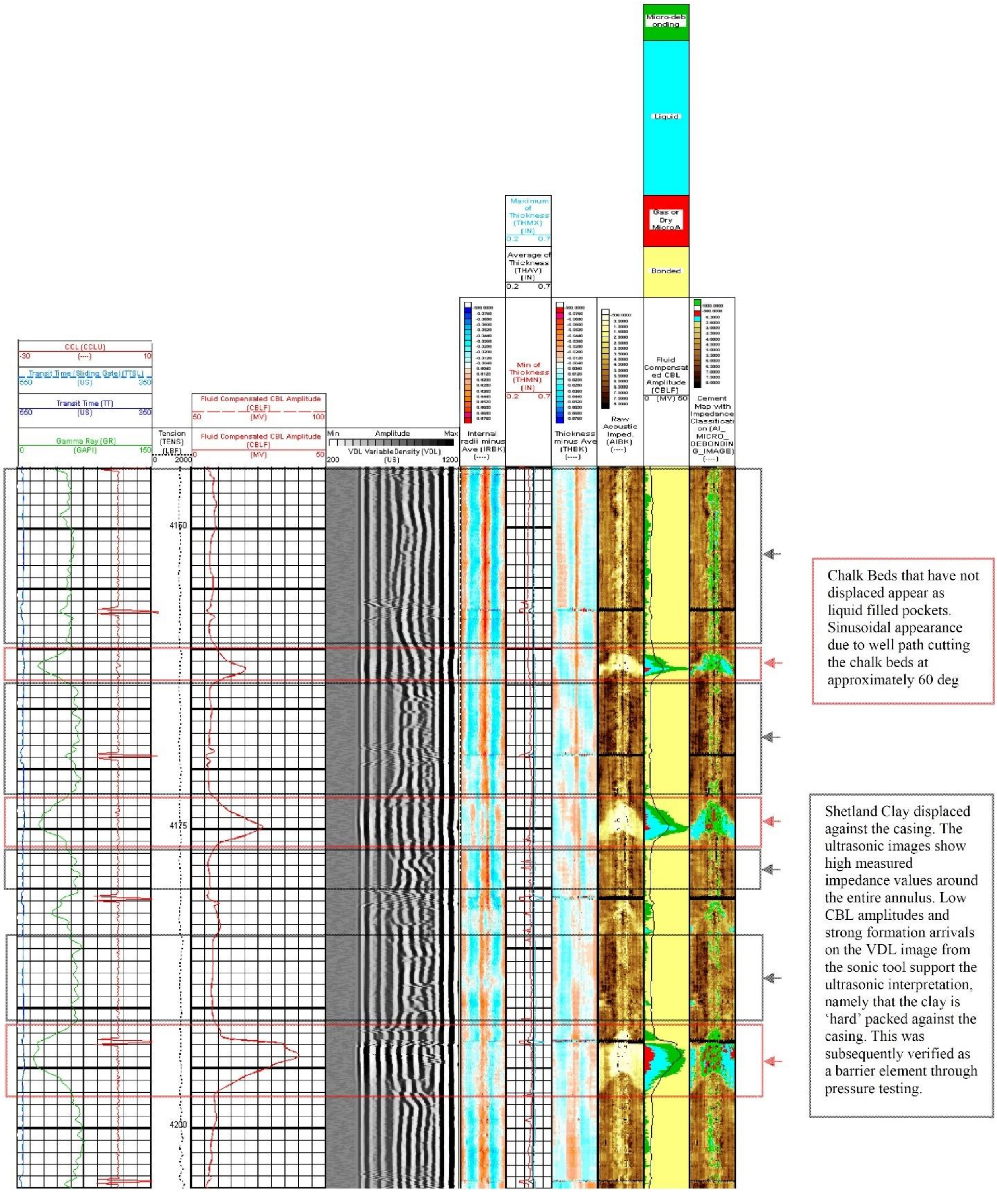


Figure 17 – CBL/VBL and Ultrasonic cement bond logs over an interval in the Shetland Clay (18)

Bonded shale formation cannot be predicted, and therefore, during the planning phase of P&A it shall be planned for using cement as barrier element outside casings. However, once shale formation is identified and qualified it can be used. Using shale, nature's own barrier, which is durable, self-healing and robust can significant reduce rig time and operating cost.

Statoil have used this method to resolve critical barrier issues on more than 100 wells, with an estimated average cost reduction of 15 mill NOK per well (21).

Shales are expected as external WBE in both NORSOK D-010 and Oil and Gas UK Guidelines. NORSOK D-010 have made WBEA criteria for creeping shale which is included in the appendices.

6 Plug Placement Methods

Setting of cement plugs is generally recognized as a simple operation. However, to place a successful cement plug in an offshore environment can be very challenging, especially as drilling move forwards to more extreme environments. (22) discusses the industry's best practise for cement plug placement in order to get the job done right the first time. To be able to place a successful plug in the wellbore, (22), state three main steps that needs to accomplish:

1. *Plug and spacer design*

   The first step involves the plug design, which includes determining the length of the plug and the spacer design, which is an important part of the plug job design as it reduces the contamination of cement.

2. *Slurry design*

   The second step involves the slurry design. The slurry design is different for each type of plug and must be designed for downhole conditions, such as bottom hole temperature (both static and circulating) and pressure. It also must be designed for requirements as expanding, chemical resistance (CO_2, H_2S etc) etc.

3. *Placement technique*

   The third and last step calls for the placement technique. In this step the following needs to be considered: Base for the plug (if placed of bottom), the use of the stringer to place the plug, balancing the plug, use of a diverter tool and rotation, and pulling out of hole (POOH) after displacement.

The placement of the well plug is a determining factor in closure quality. Therefore, should all three steps be optimized by using specialized plug cementing simulation software. Also with proper planning of all steps the plugs can be successfully set and thus non-productive time is prevented.

In the following section are different techniques to place a cement plug described briefly.

6.1 Balanced plug

The Balanced-plug method is the most frequently used method to install or palce a cement plug in the wellbore. Tubing or drillpipe is first lowered into the hole to the desired depth for the plug base. To avoid cement slurry contamination when placing the cement plug, a predetermined quantity of a stable spacer fluid is pumped in front and behind the cement slurry.

To set a balanced plug, volumes are calculated in such a way that the top of cement (TOC) and spacer in annulus are at the same height as TOC and spacer inside the the work string at the end of pumping, thus resuting in a hydrostatically balanced system. The basic assumption is that all fluid is going to remain in place while the work string is pulled out of the cement, as seen in figure 18. The rate at which the work string is pulled out of the cement should be at a velocity where the hydrostatic balance which was initially established is not disturbed, to avoid any mixing of the fluids. It is also common practise to slightly underdisplace the plug to allow the plug to reach hydrostatic pressure while pulling out of hole and to avoid mud flowback at the rig floor while breaking pipe stands.

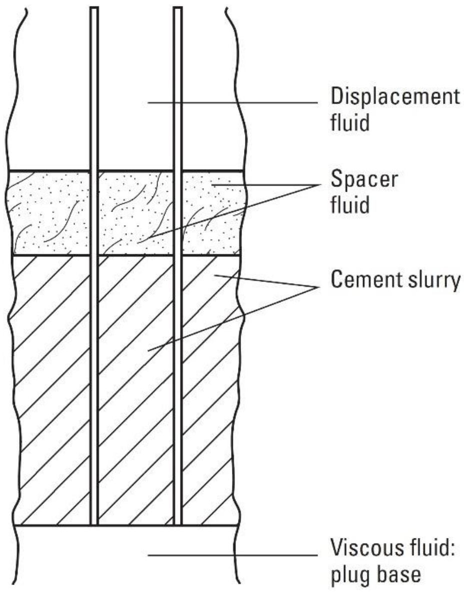


Figure 18 – Balanced cement plug (23)

Also to avoid cement contamination a high gel strength fluid (viscous fluid) can be used as a base. This would avoid downhole migration of the cement and eliminate mixing. Another solution could be to use a mechanical foundation as a base.

6.2 Dump bailer

The dump bailer method involves the use of a cylindrical container (dump bailer) that holds a measured quantity of cement slurry. Usually a permanent bridge plug is installed just below the desired plug interval. The dump bailer is run into the well with wireline, and either opens mechanically by touching the bridge plug or electronically by the WL operator. As the dump bailer opens the cement slurry is released into the well bore while the bailer is raised slowly for proper displacement.

This method is usually employed at shallow depths, but it can also be used at greater depths if the cement slurry is properly retarded. The advantage with this method is that it can be relatively fast, it does not require a rig, the depth of the plug is easily controlled and it reduces the change of cement contamination. The disadvantage however is that the container has limited fluid capacity, and thus multiple runs may be required. The cement slurry is also stationary during the decent, so special slurry-design considerations are required, especially under high-temperature conditions (23).

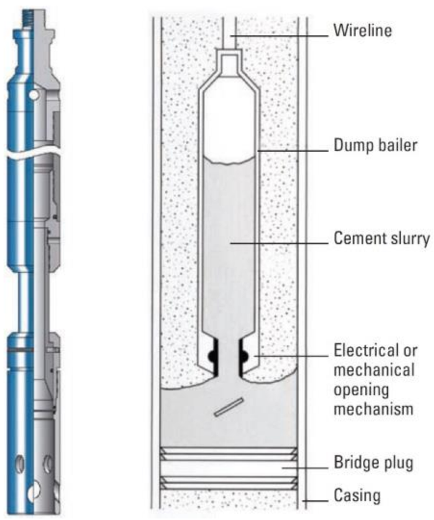


Figure 19 – Dump bailer (23)

6.3 Two-plug method

The two-plug method places a cement plug in the well with high accuracy at a calculated depth, and with minimum contamination of cement. This is performed with a special tool composted of a bottomhole sub installed at the lower end of the drillpipe, and aluminum tailpipe, a bottom wiper plug (which carries a dart), and a top wiper plug. The wiper plugs are used to isolate the cement from the fluids, and thus preventing contamination of the cement. They are also used to provide positive pressure readings at surface to indicate cement placement.

The procedure is presented in figure 20, and includes the following steps:

1. Once spacer is pumped into the work string, the first wiper dart/ball (bottom plug) is pumped ahead of the cement slurry to clean the pipe wall and isolate the cement from the spacer.
2. The second wiper dart is pumped behind the cement slurry to prevent contamination from the displacement fluid, which is pumped behind the wiper dart.
3. When the first wiper dart lands in the locator sub, pump pressure is increased to break a shear pin which is connected to the wiper dart. As the shear pin is broken, cement can be pumped into place.
4. The second wiper dart reaches the locator sub, indicating that the cement is in place. Pressure will again increase. The drilpipe is then slowly pulled out of the cement column until the lower end of the tailpipe reaches the calculated depth for the top of the cement plug.
5. Pressure is continued to increase until a shear pin between the catcher sub body and the sleeve is broken, letting the sleeve slide down and open a reverse circulation path.
6. Excess cement is then circulated form the hole.

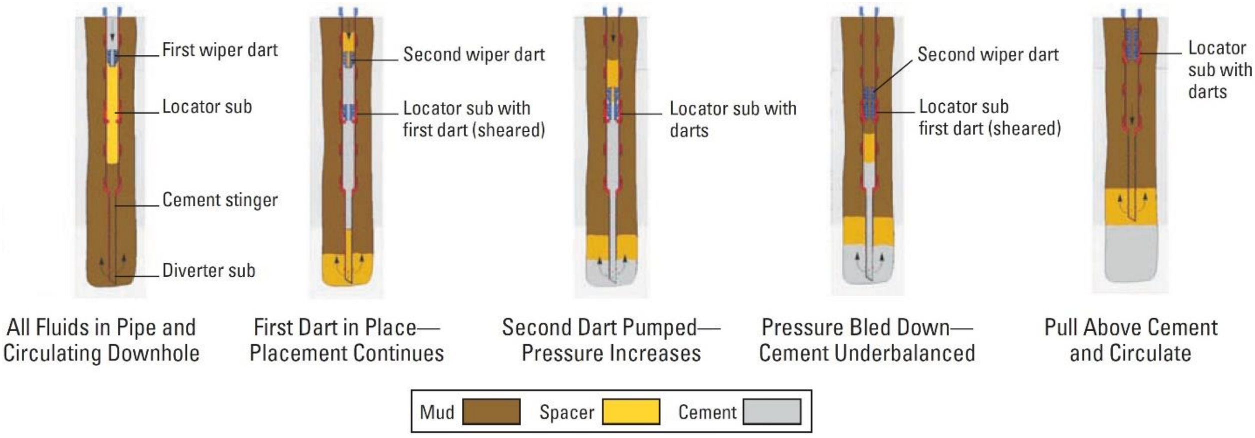


Figure 20 – Two plug method (23)

6.4Cement contamination prevention and the Use of Spacer

Cement contamination during placement of a cement plugs has long been recognized as a serious problem. Cement plugs are relatively small in volume and are therefore prone to failure. The primary consequences of cement contamination are change in setting-times and deterioration of mechanical properties. Setting-times are dependent of the thickening time of the cement slurry. Once the cement slurry is mixed, it stays pumpable in a limited amount of time before it gel-up and sets. Premature setting of the cement can be caused by contamination of the cement slurry. Fluids presented in the well can have potential to accelerate or retard the cement setting time.

Contamination of the cement slurry may occur at different times and for different reasons. Cement contamination may occur during placement, inside the drillpipe, at front and near interfaces of the slurry due to unstable base or top, owing to density differences. Additionally, the cement could be contaminated due to mud layers not being displaced form the wall or in washed-out zones where mud removal is difficult. Contamination could also be caused by over-displacement or while pulling the pipe out of hole.

To prevent contamination, several mechanical devices can address some of the causes of cement contamination mentioned above. Mechanical devises as bridge plugs and mechanical plugs can be used as a base to separate the cement slurry from the less dense fluid underneath when the cement plug is placed off-bottom. Other mechanical devices as darts and balls can be used to provide a barrier between fluids under the cement placement operation, as described in the two-plug placement method above.

As mentioned above, spacer fluids are used under the cement placement operation to prevent contamination of the cement slurry. The spacer also helps to reduce the differences in density and viscosity under the displacement, which is an influencing factor to prevent contamination. In addition, it helps to change the wettability of the formation as oil-based mud (OBM) or synthetic-based mud (SBM) can be left in the well after drilling. The wettability is changed to achieve bonding with the formation or with the casing if the plug is set inside the casing (22).

7 Plugging materials

The objective of plugging and abandoning a well is to seal the wellbore for eternity. Proper plugging material is important to in order to isolate permeable zones from each other and/or from the surface to prevent leakage of formation fluids to sensitive formations or to surface. As described in section 4.6.1, there are seven characteristics that the plugging material should fulfil according to NORSOK D-010 requirements. These characteristics are however not necessarily required, but is recommended as particularly suitable for well barrier materials. The choice of material will depend on the specific functional requirements for the conditions of the well and on the method used for placing the barrier material.

Cement has historically and is currently the prime material used for permanent abandonment of wells. There are however arguments in the industry about which sealant will provide the most effective seal over time. Cement has a long track record, but there are arguments about that cement does not have the required properties to maintain long term isolation. Lately, more attention has been given to the development of long lasting materials to ensure that wells never leak, because the cost of going back and redoing the abandonment is punishingly high. A few alternative materials have been developed, among them ThermaSet and Sandaband, which are briefly presented in the sections below.

7.1 Cement Plugs for P&A

The most common material for permanently plugging of petroleum wells is Portland cement. Portland cement is a hydraulic cement, which means when dry cement is mixed with water it sets and hardens by chemical reactions between the water and the compounds present in the cement. Such cements have the ability to not only set and harden in air, but also when placed underwater. The set cement is almost insoluble in water, which means that the hardened material is not destroyed when exposed to water.

Portland cement is produced of pulverized clinker, which contain calcareous materials and argillaceous materials. Calcareous materials are compounds of calcium and magnesium mainly from limestone and chalk, and argillaceous materials are alumina, silica and oxides of iron mainly from clay and shale. The properties of the cement are dependent by the mineralogical composition of the clinker, but different additives can be used to establish the required properties.

Cement intended to be used as plugging material must be designed to accommodate a wide range of conditions. The cement must perform at different temperature and pressure ranges, withstand corrosive fluids and over pressured formation fluids, and have the required strength in an eternal perspective.

A wide range of additives makes it possible to modify the cement to make it optimized for P&A. Cement set accelerators may be added to the cement to reduce the setting time and increase the early strength of the plug. Dispersant can be added to reduce the water/cement ratio to reduce the viscosity and provide higher strength and lower permeability. This is only a few of the different additives that can contribute to improve the properties of the cement. There are however some concerns that have to be taken into consideration when designing a cement slurry for P&A.

Some problems with the cement comes during the hydration process. The cement needs time to cure and set into a solid material. After the initial mixing the slurry will increase in viscosity, and it is important that the cement slurry has a suitable viscosity to be pumpable. The thickening time must be sufficiently long to be able to place the cement in the well, but at the same time it should develop compressive strength rapidly to save rig time.

As with most materials going from liquid to a solid state, Portland cement also shrinks during solidification. Hydration shrinkage is a concern as it may result in a separation in the plug/casing interface due to tensile stress. Normally is however the boding between the interface stronger the tensile stress coming from shrinkage. The result will then be an increase in porosity rather than deboning. However, to compensate for the shrinkage, expending agents should be included in the cement slurry. Ideally, the net expansion will be greater than the net shrinkage, causing a compressive stress instead of a tensional stress at the interface. This is advantageous as the cement is stronger in compression.

Another concern about cement is that it is a brittle material and my crack when exposed to high enough stresses. NORSOK D-010 states that materials used as permanent abandonment barriers should be ductile. This means that if the material is subjected to high stresses the material will deform, rather than crack and fail. However, cement can gain elasticity by incorporating additives such as elastomers in the cement slurry.

Several additives can be added in addition to those mentioned above. This is also one the main benefits with cement. The cement can be modified to have almost any desired property, making cement a competent barrier material. Cement has some shortcomings, but the ability to modify the cement is most likely the reason that cement still will be the most common plugging material in the years to come. It also in general satisfies the essential criteria of an adequate plug and is reliable, environmentally friendly and a cost effective sealant.

7.2 ThermaSet

An oil service company named Wellcem has developed and patented an alternative material for plugging, lost circulation, leak stop and sand consolidation, called ThermaSet. ThermaSet is a particle free multicomponent polymer resin that is pumped down in a liquid state and will be transformed into a solid by a process activated by temperature. The initiation of the curing process and curing time can be custom tailed to fit the predetermined temperatures of the formation or the area where the plug is to be set. It can be tailed within a wide range of viscosities and densities and be adjusted to determined formation temperatures between 20-150 ˚C. The viscosity range is from 10 to 2000 cP, while the density range is from 0.7 to 2.5 S.G. (24) Due to the wide range of densities and viscosities, the Thermaset can be designed to be easily pumpable and placed in the well with precision. The Thermaset can also be pumped with conventional cement pumping equipment, eliminating the need for extra equipment on the rig. Also since the material contains no particles the material can penetrate deeply into formations and seal off micro cracks and channels. Another notable property is that Thermaset is compatible with most fluids and cements, and can tolerate up to 50 % contamination and still maintain hard set competency.

Figure 21 – Thermaset

The curing time of the Thermaset can be set in the range from a few minutes to several hours. Compared to conventional cement this is a huge advantage as wait on cement (WOC) time is eliminated. The Thermaset does not shrink as it sets, which also is an advantage over conventional cement.

Once the Thermaset cures, it solidifies into a strong and flexible mass with higher mechanical strengths than cement. SINTEF has performed tests to compare the mechanical properties between ThermaSet and traditional Portland cement, with the results shown in table 5. The results show that ThermaSet has better mechanical properties than cement in almost every aspect.

It has higher compressive strength and approximately 60 times higher tensile strength compared to cement. It also has approximately 5 times higher flexural strength. This means Thermaset can withstand varying loads better than cement. Varying loads can be created downhole due to pressure and temperature cycles, causing the casing to expend and contract, and thus exerting a force on the material. The E-modulus of the Thermaset also shows better elasticity, which makes the material ductile. Although NORSOK D-010 states that materials should be ductile, cement is a brittle material and not ductile.

Table 5 – Thermaset mechanical properties from test (24)

Properties	Portland cement	ThermaSet
Compressive strength (MPa)	58	77
Flexural strength (MPa)	10	45
E-modulus (MPa)	3700	2240
Rapture Elongation (%)	0.01	3.5
Tensile Strength (MPa)	1	60
Failure Flexural Strain (%)	0.32	1.9

Compared to conventional cement the Thermaset shows high potential. The Thermaset is however more expensive and could possibly be used in wells with especially challenging conditions. The cost may be justified due to less setting time and increased long term ability.

7.3 Sandaband – Sand for Abandonment

Sandaband (sand for abandonment) is an innovative, patented plugging- and lost circulation-material developed by Sandaband Well Plugging AS. The company claims the Sandaband is an ever-lasting gas-tight material with no-segregating, no-shirking and no-fracturing.

Sandaband is a bringham-plastic unconsolidated material consisting of 70-80 % volume of solids (quartz, crushed rock, and micro silica), together with 20-30 % water. Also a small amount of dispersant and viscosifier are added to keep the material pumpable. Quartz is thermodynamically stable, and will not degrade over time, or react with other materials except concentrated hydrofluoric acid. It is also unaffected by downhole fluids as Co_2 and H_2S and hydrocarbons. The particles in the material are kept together by electrostatic forces (zeta binding) between the water molecule and the surface of the smallest micro-silica grains and hider flow in the pore space. (25)

Sandaband does not transform into a solid due to chemical reactions, and thus require no setting time, like cement. Sandaband has rheological properties like a Bingham Plastic material. Bingham Plastic fluids are characterized by the fact that they behave like a solid until the applied pressure is high enough to break the shear stress, and thus making the fluid to flow. The stress required for the fluid to start flowing is called the yield stress, or yield point. Above this point is the fluid flows, and the shear rate is linear with the shear stress, like a Newtonian fluid. This is illustrated in figure 22 where the difference between the behaviour of a Newtonian fluid (ordinary viscous) and a Bingham Plastic fluid (sandaband) is shown.

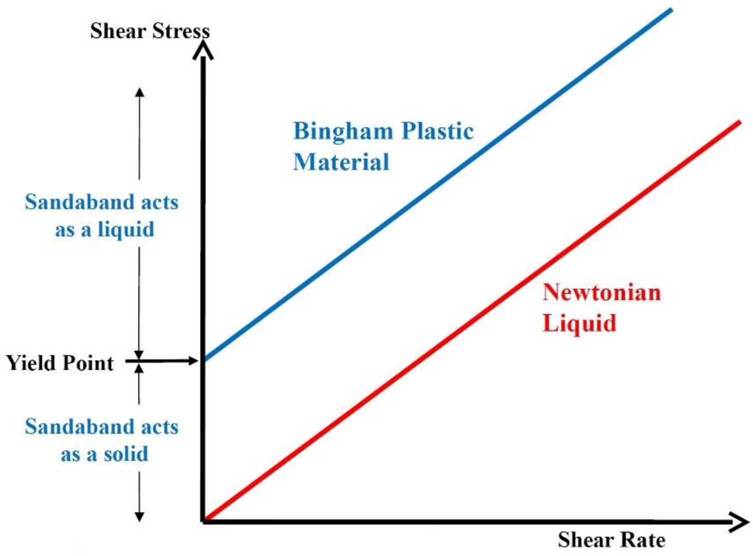


Figure 22 – Bingham Plastic behavior (26)

Due to the properties of a Bingham Plastic fluid, the setting time is not time-dependent. This means once pumping is stopped, the slurry will rapidly form a rigid body. This also means that when the material is exposed to dynamic loads causing stresses in the material, the material will deform and reshape, rather than fracture and crack like a brittle material. This eliminates leakage through fractured channels or microannuli.

A disadvantage is that Sandaband required a permanent floor or solid base to be placed on. If it is placed on top of a liquid, it will fall through due to density difference. This means that the material must be placed on a mechanical plug. This could be risky in a long term perspective if the mechanical plug should fail. If the foundation would fail, the material would sink and re-position itself, but then not provide the same level for safety. To set the material in combination with a mechanical plug is also not optimal as the mechanical plug is not accepted as a permanent barrier.

Sandaband has been tested to qualify as gas tight element, with and without additives in accordance with API spec10. It is however not directly adequate to test the sandaband with this method as this test procedure is made for cement. A long-term integrity test has also been conducted and the material has been tested in the temperature range -10 ˚C to 250 ˚C. A company called Proffshore has also made a WBEA criteria table for Sandaband. (25)

Figure 23 – Sandaband (26)

8 The P&A operation

8.1 Required Information for the P&A operation

There are different types of wells that are used in the petroleum industry. Exploration wells, appraisal wells, production wells, and injection wells, are all used under the development of an oil and gas field. Each well have its own design fit for its purpose. During the wells life cycle, many parties are involved, from planning, drilling, completion, maintenance, intervention and finally plug and abandonment. Complete recordkeeping of the wells design, past work, well performance and reservoir condition throughout the life of the well will be a key when planning for P&A. However, during the wells life cycle, information about the well characteristics can have been lost. This is especially a challenge for many old wells that needs to get plugged and abandoned.

Due to all the differences and uncertainties, it is difficult to make a standardized P&A program for all wells. It is therefore important to gather as much information as possible to ensure that the P&A operation is executed as successful as possible. Several factors are influencing the P&A program and how the operation will be conducted, but information about the well status, type of well, casing program, completion equipment, status of cement, number of potential inflows etc. are important parameters in the design basis for the P&A program. According to NORSOK D-010 the following parameters should be included in the design basis for the well barrier design and abandonment program.:

a) Well configuration (original and present) including depths and specification of formations that are sources of inflow, casing strings, casing cement, wellbores, sidetracks.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, current and in an eternal perspective)
c) Logs, data and information from cementing operations.
d) Formations with suitable WBE properties (e.g. strength, impermeability, absence of fractures and faulting).

e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene or similar issues.

8.2 P&A Phases

Phase 1 – Reservoir Abandonment

The first phase involves to place a primary and secondary permanent barrier to completely isolate all reservoir producing or injection zones from the wellbore. This can be performed while the tubing is in place, or the tubing can be partly or fully retrieved.

Phase 2 – Intermediate Abandonment

The purpose of the second phase of permanent P&A is to seal all potential intermediate zones with flow potential. This often includes pulling of tubing and upper completion to get access to the annulus to evaluate the condition of the annular barriers. The interval from the production packer and up is referred to as the upper completion. As the annular barriers have been evaluated, operations such as milling or a new method called PWC may be conducted to set intermediate barriers against a shallower reservoir. It can also be necessary to set barriers between zones with flow potential to isolate them from each other, and avoid communication within the wellbore. In the end, an open hole to surface barrier is set to completely isolate the well. The phase is completed when all required permanent barriers are set.

Phase 3 – Wellhead and conductor Removal

Phase 3 is the last phase of the P&A operation and consists of cutting and retrieving of the wellhead and the following casings strings. The newest revision of NORSOK D-010 has no requirements when it comes to cutting depth of the casings. NORSOK D-010 states however that the cutting depth shall be sufficient to prevent any conflict with other marine activates and at a depth where no remaining equipment will stick up in the future.

The conventional method of doing this operation has been by cutting one casing at a time with cutting knives and subsequently pull it out of hole. Another method has been by using explosives, but this is less controllable and have some health, safety and environmental (HSE) risks. In addition, these kind of operations have been executed with the use of a rig. Lately, new technology has emerged which utilizes abrasive water jet technology. The new technology can also be conducted from dedicated vessels. Removing wellheads and the following casings strings can then be performed in campaigns during periods with good weather. By using dedicated vessels much rig time can be saved and subsequently reduce the cost. This will not be further discussed in this thesis.

After this phase is completed, the well will never be used or re-entered again.

Figure 24 – Trolla wellhead on deck (27)

8.3 P&A Operational Procedure

As mentioned, each well has its own design and problems, and are therefore unique. All these variations make the P&A operation unique for every well and the operational procedure different from one well to another. There are however many sequences that are shared for most operations. In the following is a general operational procedure described which includes the main steps of a P&A operation.

1. **Planning & research**

   As previously discussed, it is important to gather information about the well to obtain the required data for the design basis of the P&A program. A P&A program will then be designed based on existing well records and reservoir conditions together with the present and future condition of the well and reservoir. The P&A program will also be designed to meet regulatory requirements with the goal to secure the well to prevent any future leaks.

   All parties participating in the P&A operation should decide what equipment is needed, and who is obligated to bring each piece of equipment. A decision must also be taken on which rig/vessels are necessary to perform the operation. The involved parties should also verify that they have the proper personnel with the right training and experience to run the operation.

   The P&A work can be divided into campaigns if several wells scheduled for P&A are in close proximity. In this way the operations can be streamlined by performing work on one well and then move to the next without the expense of repeated mobilization.

   Effective planning and coordination of all activates reduces the nonproductive time and increases the chance of a smooth and cost-efficient operation.

2. **Preparation & preliminary well-site work**

   Prior to any activity, the surface-equipment are tested and the wellbore is inspected. All the valves on the wellhead and x-mas tree are checked to ensure functionality and integrity during the operation. Wireline equipment is rigged up and used to check wellbore conditions, obstructions, internal diameter of tubing, and to pull the downhole safety valve (DHSV). In wells where obstructions are encountered, extra preparatory work is needed to re-open the well. The knowledge of present status of the well will be incorporated in the planning of P&A operation.

3. Kill & secure the well

Before the P&A operation can commence, it is necessary to kill the well. To kill the well a column of heavy fluid is placed in the well to produce a hydrostatic pressure which will shut off flow into the wellbore. This will make the well overbalanced, i.e. a hydrostatic pressure greater than the formation/pore pressure.

If normal well killing techniques are not possible, the well can be killed by bullheading. During this operation, kill fluid is pumped into the well against pressure to force wellbore contents back into the formation. The wellbore fluid is then replaced with a high density fluid which will maintain a stable overpressure once pumping is complete.

4. Check pressure in annulus

It is important to check for any pressure build up in the annulus before the tubing is cut and pulled. This is especially important for subsea wells as these annuli cannot be monitored. On platform or spar-type wells the annular pressure can usually be bled off thorough surface accessible wellhead equipment. Annular pressure buildup is pressure generated by fluids that are trapped in the annulus. During production, heat transfer makes the fluid to expend causing a substantial increase in pressure. After the pressure is bleed off, it is looked for a rebuilding of pressure. If the casing shoes are left open, they can serve as a pathway for continuous pressure buildup in the annulus. Figure 25 shows an example of an offshore platform well, where pathways into the casing annulus are present. This kind of pressure buildup is called sustained casing pressure and causes integrity issues as the tubing is removed.

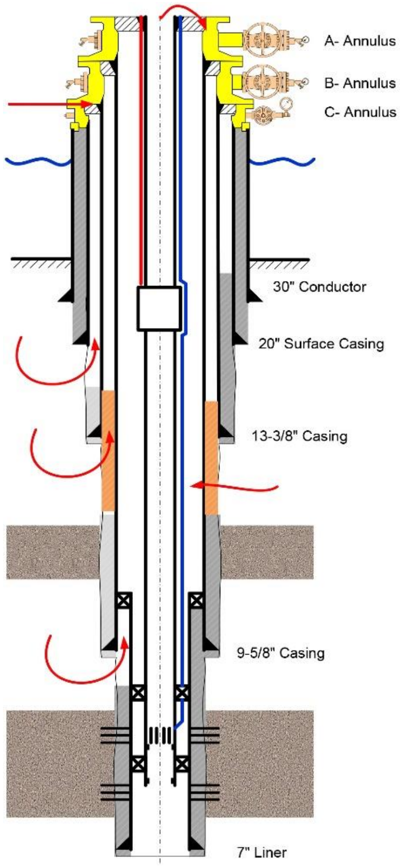


Figure 25 – Platform well indicating potential leak paths resulting in SCP (28)

5. Cut tubing

The tubing is cut a few meters above the production packer and below the downhole gauge. It is also important to cut the control lines (if present) at the same time. The cut will therefore me made close the control line clamps. This ensures that the tubing is free to be POOH. The tubing needs to be pulled out of hole to get access to the 9 5/8" casing in order to evaluate if there is good cement/isolation behind the casing in the area where the internal cement plug will be set. Another reason to pull the tubing is if control lines are attached to the tubing. Control lines and downhole equipment can cause loss of integrity by creating leak paths and shall according to NORSOK D-010 requirements not be part of a permanent barrier.

6. N/D X-mas tree and N/U BOP

There is a difference in performing P&A operations on vertical X-mas trees (VXT) and horizontal X-mas trees (HXT). VXTs are the conventional type, often used on older wells. Wells equipped with VXTs are already secured with primary and secondary temporary barriers. VXTs are therefore retrieved before the tubing is pulled. HXT on the other hand are retrieved after the tubing is pulled, but after a deep and shallow plug are set.

While all steps above can be performed rig less with wireline, a rig is now needed for the upcoming heavier tasks. To ensure well control and access to the well, the (vertical) X-mas tree is removed to make space for the blow out preventer (BOP) (and risers if subsea well). The XMT is nippled down (N/D) and the BOP is nippled up (N/U). There are two major types of BOPs, annular and ram type. Most BOP stacks utilize both with at least one annular BOP stacked above several ram BOPs. Three ram types are common, blind ram, pipe ram and shear ram. The rams are able to cut the drillpipe or seal the tubing in the event of an emergency. The BOP provides maximum pressure integrity, safety and flexibility during the revival of the tubing.

7. Retrieve ASV

Annular safety valves (ASV) are typically installed in gas-lift completions to prevent uncontrolled flow in the A-annulus when actuated. The ASV can be tubing- and wireline-retrievable. Wireline retrievable valves are easily installed and removed without the need for a rig. These vales can be removed during the offline work. Tubing retrievable valves is run and retrieved as an integral part of the tubing. These valves are then retrieved together with the tubing and control lines.

8. Retrieve tubing and control lines

Tubing retrieval is considered as a heavy lifting operation and requires heavy duty lifting/pulling equipment to retrieve the tubing from the well. In some cases, the original drilling equipment on-board the platform well has been removed and a jack-up rig has to be mobilized to retrieve the tubing. For subsea wells, semi-submersibles have to be mobilized.

9. Run logging tools

As the tubing is POOH, the production casing is revealed, and logging tools can be run. The logging operation is performed to check the quality of the barrier element behind the casing. To check the quality or existence of annular barrier, CBL and USIT logs are run. These logs are further described in section 5.1 and 5.2 respectively. If interpretation of the logging data shows that the casing cement is of good quality, a plug can be easily set inside the casing. Interpretation can also show shale that has collapsed against the casing which also can be used as an external barrier element, this is further described in section 5.3. If the interpretation shows poor or lack of annular barrier element, section milling or perforate, wash and cement technology can be used respectively.

10. Establish well barriers

Depending on the results of the interpretation of the well logs, the well configuration, number of sources of inflow etc. different well barrier solutions can be utilized.

In some cases, it is desired to plug perforations within the reservoir zone. This may have been done towards the end of the wells life cycle to eliminate production of water form a depleted water drive formation. It can also be desired to plug the perforations to eliminate that injection water enters the well from a well in close proximity which is used for pressure management. In most cases the perforations are plugged to eliminate the entry of undesirable fluids into the wellbore. This can be conducted by squeezing cement into the perforations after the well is killed.

In other cases, it is not necessary to plug the perforations, and a mechanical plug can be placed above the perforations. Mechanical plugs or bridge plugs are used to provide a solid base for the upcoming cement plug. In cases where there is a potential for moderate pressure or fluids entering from an area below, the bridge plug will be set to reduce the change to contaminate the cement. The bridge plug can be set after the well is killed to act as a temporary barrier against formation pressure and later be a foundation for the primary barrier.

Assuming that a bridge plug has been set according to depth requirements, the primary barrier will be set on top of the bride plug. For the secondary barrier various solutions can be utilized.

After the reservoir is plugged with primary and secondary barriers, the intermediate zones are plugged. It might be necessary to pull the production casing to log behind the intermediate casing, and then set plugs in the intermediate casing. In the end is a surface plug or open hole to surface barrier set. It might be necessary to also pull the intermediate casing in order to establish a full cross-section barrier in the surface casing.

11. Cut & retrieve wellhead

The final stage is to cut and remove the upper part of conductor and following casing strings and retrieve the wellhead. The conventional method of performing this operation has been by the use of a rig. Lately several vessels have emerged that can perform this operation more cost efficiently.

9 P&A challenges

9.1 Knowledge of well status

A common challenge for wells that needs to get plugged and abandoned is lack of information and uncertain condition of the well status. The majority of wells in the North Sea were drilled and completed through the decade of 1980. At the time, technology, procedures and information management was not at the same standard as we know it today. Data available from these wells exist primary in paper hard copies or their scanned versions. These records can be of bad quality and they frequently provide insufficient data to determine the downhole conditions of the well.

Unknown downhole conditions such as leaking elements, mechanical obstructions, corrosion, annulus pressure etc. are often encountered in ageing wells. Many wells may have been suspended or temporary abandoned for many years, and there may be uncertainties of the actual well status of these wells as well.

A particular parameter of interest is information about the cement quality behind the casings. The cement quality has a large influence on how the whole P&A operation will be carried out. The ideal condition is a fully cemented casing with good bond/isolation between the casing and the formation where internal cement plugs can be easily set. Unfortunately, satisfying cement behind the casing is rarely the case. The cement might be of inadequate quality or totally absent. This is often the result from unsuccessful or poor cement jobs, and is often seen in old wells.

Lack of information on the well's status makes it necessary to perform preliminary investigation work before starting the P&A operation. This may require the use of rigs with conventional BOP and riser to be able to do the job in a safe and controlled manner.

9.2 Competent formation and pressure exposure

When a well is to be plugged it must be identified where there are formations with sufficient formation strength to hold pressure from a reservoir below. This information is normally obtained when the well is drilled, but in old wells this information is not always available. In that event it requires to conduct physical test of the formation as part of the plug and abandonment operation.

The sealing materials used for plugging and abandonment must be designed to withstand the maximum pressure they may be exposed to. Production changes conditions such as pressure, thermal and stress down-hole in the reservoir. These changes occur during production, but continues after shut-in until an equilibrium is reached. Wells that have been shut-in for a long period (10-50 years) may have built up pressure to original virgin pressure, or in worst case higher if the field have been subjected to gas or water injection. The worst anticipated reservoir pressure has to be taken into account for the abandonment period, and must be established with reasonable certainty.

The formation strength and reservoir pressure has a large influence on the setting depth of the plugs. For more info, see section 4.6.2

9.3 Collapsed tubing/casing

Many wells are located in fields where reservoir compaction and surface subsidence has occurred due to depletion during the fields life. As fluid is produced from a reservoir, a reduction in pore pressure occurs. The weight of the overburden is partially supported by the rock matrix and partially by the pore pressure within the rock space. When the pressure is reduced, more weight is transferred to the rock matrix, and the formation is compacted. This compaction may impose shear stresses on the well which can cause the tubing/casing to collapse or shear. Tubular failure can also be caused through several other mechanisms, including compression, buckling and bending modes. Casing damage induced by formation compaction has occurred in reservoirs at the Valhall and Ekofisk field in the North Sea. Casing deformation can influence the productivity, integrity and the ability to re-enter a well.

When plugging a well it is a requirement to set the plugs at a depth with sufficient formation strength to withstand any pressure from below. If plugs need to be set below depths where the damage has occurred, it will be a major challenge to plug and abandon the well in a safe manner.

9.4 Removal of control cables and lines

The majority of well on the NCS have control lines or cables attached along the tubing to monitor and control the wells. For the P&A operations this is an issue as the control lines have to be removed in areas where the permanent well barriers shall be installed. The control lines can constitute as a leak path if they are left in the well. The only way of removing the control lines is by removing the entire tubing. This requires heavy duty equipment which can handle high loads, thus contributing as an expensive part of the P&A operation. The challenge is how one can prevent leak paths from the control cables, without having to pull the tubing.

9.5 Ability to log cement quality through multiple casing

Prior to performing a P&A operation it is essential to know the condition of the annular or external barrier outside the casing. This information is normally obtained by running a CBL and USIT log. The logging technology currently in use has not the ability to log through multiple pipes, either multiple casing or the casing and tubing. In some situations, it is therefore necessary to pull tubing/casing out of hole to be able to validate the condition of the annular barrier. Technology which could validate and identify the existence and quality of annular barrier behind dual tubulars will significantly reduce rig-time used on casing removal.

9.6 Cement evaluation

The most common method to validate the quality of casing cement as an annular barrier is by logging. These logs needs to provide reliable data as the cement will be a part of the permanent barrier that will seal the wellbore for eternity. However, sometimes these logs show bad quality even when the primary cement jobs are known to be successful, and they might even show a different result when the logs are repeated. Furthermore, these logs are often a challenge to interpret. The interpretation is also dependent of highly specialised expertise, but are still often linked to personal opinions. This means that one workgroup may get a different result than an another group. This increases the risk of failure as there are uncertainties in the evaluation of the cement.

10 Conventional technologies for P&A

To permanently abandon a well successfully, the well barrier must seal the wellbore cross section both vertically and horizontally and include all annuli. When placing a well barrier element (e.g. cement plug) at a desired interval in the well it shall be positioned where there is a verified external WBE. Ideally, there is a sufficiently long interval of verified good cement around the casing and a cement plug can be placed inside the casing. This is a simple operation, and is referred to as a cased hole cement plug.

However, satisfying primary cement at the desired interval is not always the case. The cement may be of poor quality in the annulus or even missing all together and there is no way no access the last open hole section. To efficiently seal the wellbore, conventional permanent abandonment activities has required the removal of wellbore pipework. This has traditionally been done my cutting and pulling of pipe, or if the casing cannot be retrieved a proper length needs to be milled.

10.1 Cut & pull

Most petroleum wells are completed with several casings strings of progressively smaller diameters. For the conductor and surface casing, the annulus is generally cemented all the way to surface. For the intermediate and production casing the top of cement (TOC) varies as different formation zones needs different heights to be covered. The requirement today is that the casing cement shall be minimum 200 m MD above casing shoe or a potential source of inflow, the industry practise has however changed over the past decades as regulations have been reformed.

If the annulus contains little or no cement, the casing can be cut at the required depth and pulled out of hole. Typically, during this process, multiple trips are required to remove each casing string. If it is not possible to pull the casing at the first attempt, a new cut has to be made and the pulling process is repeated until the casing is recovered.

Considerable rig time must be used for a cutting and pulling operation. Time and expense are also increased when multiple cuts are necessary to retrieve the casing.

10.2 Section milling

When the casing strings cannot be cut and retrieved, a desired length needs to be milled. In some cases, the casing can be stuck due to settled particles or other obstructions as poor quality cement. To achieve a proper seal, the casing and poor cement needs to be removed and an appropriate barrier set in place.

In some cases, multiple annuli are required to be sealed. But, the technology currently in use cannot log through dual tubulars to determine cement quality. Consequently, removal of pipe is then required to log and validate the condition of the cement outside the casing/tubing.

Lack of sealing outside the casing will require a section of the casing to be grinded away along with the cement and the contaminants behind it. To accomplish this a milling tool is lowered to the desired depth and a pressure is applied to extend the cutting knives. A cut is made in the casing by applying a rotational force to the tool, and then weight is applied to push the mill in a downward direction. After the milling is performed, the open hole is cleaned to get rid of as mush debris, swarf and mud as possible. The open hole is then under-reamed to beyond virgin drilling hole size to expose fresh formation and achieve good bonding when setting a cement plug.

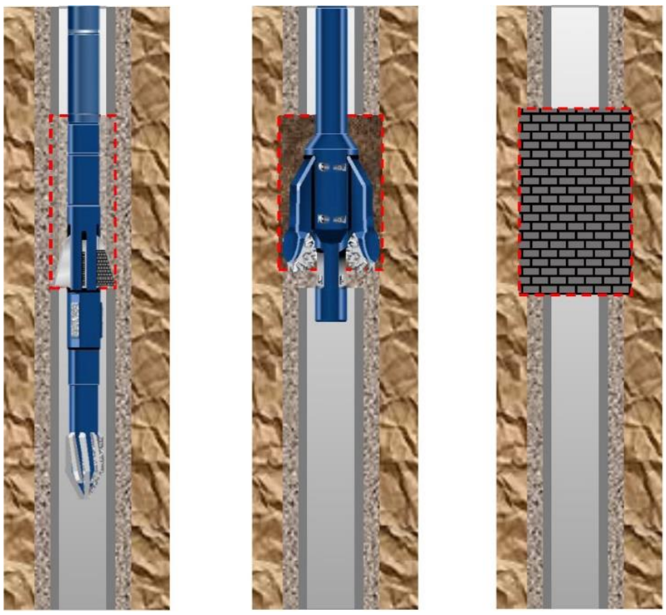


Figure 26 – Conventional section milling operation (29)

10.2.1 NORSOK and Section milling

The newest revison of NORSOK D-010 includes a manual or flowchart on how section milling can be applied to establish well barriers when section milling is required. The flowchart presents a step-by-step procedure from the logging of casing annulus to the cement plug is set and verified.

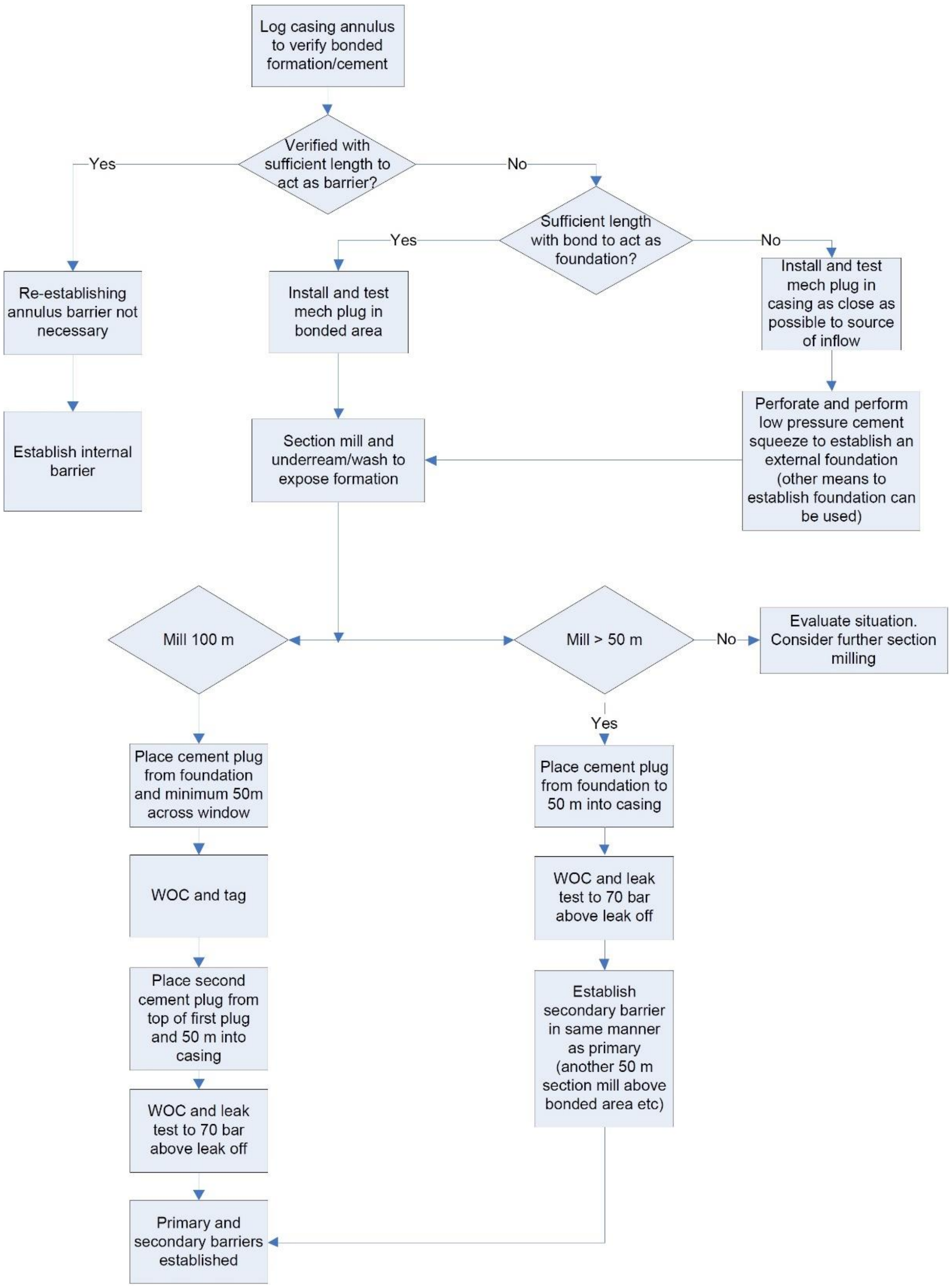


Figure 27 – Section milling flowchart (5)

10.2.2 Challenges with Section milling

To be able to set a full cross section barrier in the well the traditional method has required section milling of the casing if the casing is considered irretrievable. Section milling is a complex and time consuming operation which encompass several challenges. The operation can be difficult to execute safely and efficiently and is associated with high cost. In the following, some of the challenges associated with section milling will be presented.

10.2.2.1 Open hole exposure

As section milling removes a section of the casing and annulus cement, an open hole with direct contact to the formation will be exposed. The milling fluid profile should be designed to stay close to the average between the fracture pressure and the pore pressure as this causes the least disturbance on the borehole wall. The milling fluid must therefore be designed to have sufficient weight to keep the open hole stable and sufficiently high viscosity to transport swarf and other debris to surface. As swarf generally is much larger and have much larger density than normal drilling cuttings, the milling fluid requires higher density and viscosity to be able to lift and transport the swarf to surface. This can create Equivalent Circulating Densities (ECD) which exceed the fracture gradient of the open hole section and lead to loss of fluids, swabbing, well control problems, poor hole cleaning and packing of the BHA (30).

10.2.2.2 Milling fluid and hole cleaning

The main function of the milling fluid is to transport swarf and other debris to surface. Many of the problems associated with hole cleaning during milling operations are similar to those encountered during drilling operations when drilled cuttings are transported to surface. The main difference, as stated above, is that swarf is generally much larger and denser, and is also more irregular shaped, than drilled cuttings (31). This means that the milling fluid needs a sufficiently high viscosity to be able to transport swarf to surface, and it is important to keep the effective viscosity as high as possible while keeping the exposed formation stable.

It is also important to know what type of mud that was used during the primary drilling of the well, as traces of settled mud behind the casing can affect the properties of the milling fluid being used. As water based mud (WBM) is generally considered as preferable milling fluids, it is important to design it such that its properties will not be affected if mixed with contaminants from oil based mud (OBM).

The generation and transportation of swarf has a big impact on hole cleaning. Big and irregular metal cuttings can build up and develop into “bird-nests”. Such pack-offs can occur both downhole and topside in areas with reduced annular velocities, like in the BOP cavity or in the riser. Pack-offs can also create restriction for the cutting transport and potentially lead to stuck pipe or pack-off induced mud losses.

10.2.2.3 Damaging BOP

The Swarf that is successfully transported to surface has passed through the BOP. The swarf can accumulate in BOP cavities and consequently generate integrity issues. The most critical areas are in the ram seals and the annular seal inside the BOP. To get access to the cavities and prevent integrity issues, the BOP must be dismantled, inspected and repaired. This means that heavy lifting operations are needed, especially if the BOP is located subsea. Additional time consumption leads to considerable expense.

10.2.2.4 Vibration

The section milling assembly is also subjected to a high level of axial and torsional vibrations. These vibrations are generated as the cutters on the mill assembly grinds away the metal casing. For the milling to be successful it is important that the rig is stable during the operation. If situations occur where the rig moves, small and rapid deflections will be transplanted to the milling assembly, causing the cutting blades to make irregular depth of cuts. The vibrations will in turn exacerbate the irregularity of the cuttings. The result of this will be a reduction of ROP and a damaged BHA (32).

The milling assembly has normally incorporated a stabilization feature to moderate vibration, but the BHA must still endure considerable impacts (33).

The vibrations can also propagate to the derrick and rig, triggering loose objects to drop.

10.2.2.5 Wear of the Mill

Worn out cutters are a common phenomenon during milling operations. Worn out cutters needs to be exchanged with new cutters to maintain efficient milling. This is however time consuming as the BHA needs to be pulled out of hole to change the mill. How fast the mill is worn out depends on several factors as the chemistry and design of the cutters, the quality of the casing/tubing, the quality of cement in annulus and the weight applied on the mill.

10.2.2.6 Swarf generation and handling

The term "Swarf" is used to describe metal shavings or cuttings which are generated during the milling operation. As presented above, it is implicit that the generated swarf is the root cause of many of the challenges related to the section milling operation. Halliburton states that milling a 50 m section of casing will generate around four metric tons of swarf. The weight of generated swarf is obviously depending on the casing being milled, and its properties like weight per unit length, inner and outer diameter (wall thickness), condition (corrosion/erosion) etc. Table 6 is presented as an example. It presents the weight of 50 m and 100 m of a 9 5/8 in. casing (L-80) with different wall thicknesses. L-80 is one of the most commonly used casing steel grades under normal circumstances.

Table 6 – Weight of casing (L-80) with different dimensions

	Grade L-80		
Weight (lbs/ft)	40	47	58,4
Weight (kg/m)	59,5	69,9	86,9
Wall thickness (inch)	0,395	0,472	0,595
Weight of 50 m (kg)	2976	3497	4345
Weight of 100 m (kg)	5953	6994	8691

This means however that huge amounts of swarf needs to be circulated out of hole and transported to surface. Haliburton also states that operators only recovery approximately 25 % of the generated swarf. This means that the swarf left in hole can interfere with the cementing operation and possible make the WBE (e.g cement plug) insufficient.

Swarf that is successfully transported to surface must be handled with precaution. Drilling personnel needs to wear special protective equipment to avoid injuries when handling the sharp metal cuttings. The swarf must also be separated from the milling fluid by surface handling equipment. In order to separate and capture the swarf form the active mud system, the handling equipment is installed within the return flowline after the bell nipple and in front of the shakers (30).

The captured swarf and debris will be collected in containers and stored on the rig deck. The containers will then be transported by supply boats to shore and be disposed.

Figure 28 – Swarf from milling operation

10.2.2.7 Plug verification

As the milling operation is complete and the hole is circulated clean a proper WBE is placed in the well at a desired interval. To ensure that the barrier is effective, it is essential to test and verify that the WBE meets the acceptance criteria. Verification of the competency of plugs set using section milling techniques can be a challenge.

There are two principal methods when setting a cement plug in a milled section: 1) leaving the TOC inside the casing above the milled window, or 2) leaving the TOP in the open hole.

For the plug set with TOC inside the casing, the plug will be verified by tagging, weight testing and pressure testing. As the TOC is left in the casing, these test will only evaluate the quality of cement inside the casing and not determine the quality of cement in the annulus or open hole.

In the case where the TOC is located in the open hole it becomes impossible to verify the plug by a true pressure test. Applying high pressure could fracture the formation that is left open between the plug and the casing. The plug can however be tagged to verify position, but that does not help as its sealing ability cannot be verified.

It is difficult to assess the sealing capability in either of the cases (30).

10.2.2.7 Time consumption

Low ROP, lots of tripping and all the challenges encountered makes the section milling operation a time consuming and complex operation. A common challenge for wells that needs to get plugged and abandoned is lack of information and uncertain condition of the well status. This makes the operation even more difficult as decisions have to be made without proper knowledge.

All uncertainties and contingencies that are encountered during the operation makes it difficult to determine the expected duration of the operation. Statoil spent an average of 35 days when plugging wells in the period 2005-2010. The operation can be done fast under ideally conditions, but it can easily take 60 days with all contingencies that can be encountered.

In 2008, ConocoPhillips plugged and abandoned two out of eight water injection wells on Ekofisk 2/4 W. The average duration was 65 days per well. ConocoPhillips was not satisfied with this and made a joint cooperation team with Baker Hughes to improve the performance on the remaining six wells.

11 HydraWell's PWC technology (34)

HydraWell Intervention AS was founded in Stavanger, Norway in 2008 with the aim to develop and commercialize step change technologies.

HydraWell have since the start-up developed a method which eliminates many of the problems associated with conventional section milling operations. The new innovative method for creating a permanent abandonment plug is termed Perforate, Wash, and Cement (PWC) and was developed to enable plugging of a well without performing a section milling operation.

As the term implies, the method consists of three successive sequences: 1) Perforate a selected interval of an un-cemented casing, 2) Wash the annular space in the perforated interval, and 3) Mechanically place a cement plug across the wellbore cross section.

HydraWell have created two generations of tools which utilize the PWC method. There are a third generation which is under development, but the author has not been given the right to write about this now. The first generation PWC tool HydraWell invented was named HydraWash. The HydraWach system was developed to plug and abandon a single casing with one annulus. Through further development of the PWC method, a second generation PWC tool was invented to enable plugging a well across multiple annuli. This tool was named HydraHemera. The second generation was not only improved to enable plugging across multiple annuli, but the washing tool was also improved to clean in a satisfactory manner through several annuli.

Both PWC tools can be run either as a single-tip or as a dual-trip. The single-trip system completes all the successive sequences in one run, and is as a result less time consuming.

In the following, both systems will be presented in detail and the operational sequences will be explained.

11.1 Annular space evaluation

Before the PWC operations is conducted, cement evaluation logs should be run to evaluate the condition of the annular space. This is done to determine the condition of the sealing material outside the casing. The logs are useful to determine if there are presence of pockets, cracks and channels, or whether there are barrier material as collapsed formation or cement behind the casing. On the basis of the evaluation together with setting depth requirements a setting-depth interval for the plugs is established. The minimum plug setting depth is usually where there is free pipe and the formation has sufficient integrity. Positioning and setting depth requirements were described in section 4.6.2.

11.2 The HydraWash system – first generation PWC tool

As stated earlier, the HydraWash system is HydraWells first generation PWC tool for plugging a well with one annulus. Before the operation, evaluation of the annular space is conducted, the production tubing is cut and pulled, and casings may have to be removed if several annuli are present.

11.2.1 The tools

The HydraWash system consist of a single run assembly, containing tubing-conveyed perforation (TCP) gun with disconnect, the HydraWash and the HydraArchimedes (34).

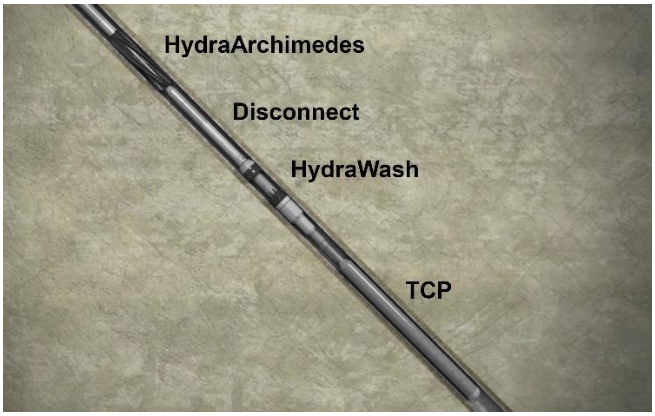


Figure 29 – HydraWell singe run assembly (35)

11.2.2 TCP gun & design

The TCP gun is positioned at the bottom of the HydraWash system. The length of the TCP gun depends on the desired perforation interval, but the overall drillpipe-conveyed perforation gun is approximately 200 ft. (60 m), when placing a 165 ft (50 m.) cement plug. It is comprised of a 35 ft. of pressure activated firing head with auto drop mechanism and a 165 ft. of hollow carrier, loaded with explosives.

The perforation guns are designed to shot 12 shots per foot (SPF) in a 9 5/8” casing with a 135/45-degree phasing. This implies that each perforation is shot with 135-degree beam when moving one inch in lateral direction. It also implies that it is 45 degrees between each perforation when moving horizontally.

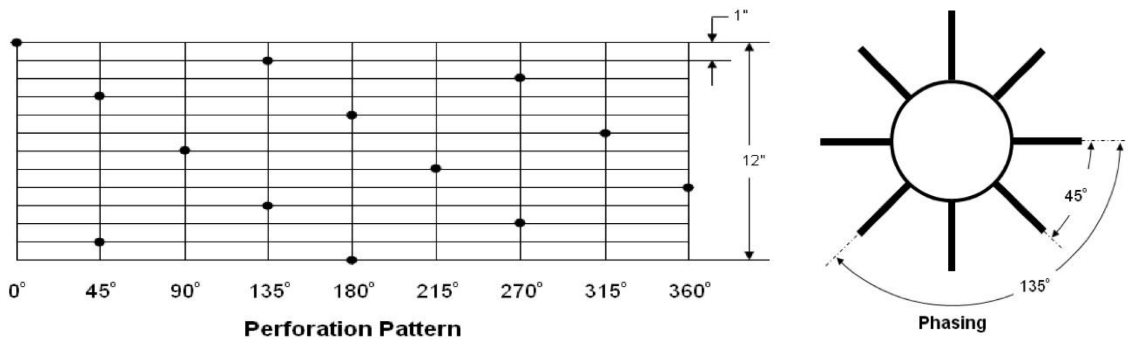


Figure 30 – Perforation pattern and phasing (36)

The diameter of the perforations is set up as a function of limited entry principles, and is normally between 0,30 and 0,50 inch. The top and bottom 7 ft. (20 m) of the perforations are however perforated with larger diameter perforations. The top perforations have a larger diameter to facilitate easier imitation of washing behind the casing without exceeding formation fracture pressure. While the bottom perforations are larger to ease the displacement of mud by cement spacer and subsequently the displacement of cement spacer by cement during the plug setting operation.

The phasing and hole size of the perforations may vary, but should be designed to ensure proper hole cleaning and a sufficient cement operation.

After the perforation guns are fired, the perforating assembly is automatically dropped and left in the well. This can only be done if the rate hole is long enough to facilitate the released TCP gun. Rat hole is the available section in the well where equipment can be left without disturbing the well barriers. If the rat hole is not sufficiently long, it forces the operation to be performed in a dual-run.

11.2.3 HydraWash

Above the TCP gun is a wash tool (HydraWash), which is isolated between two elastomer wash cups. The HydraWash tool is designed to ensure optimum hole cleaning and is used to wash out old mud, barite, old cuttings and cement traces in the annulus behind the casing.

The HydraWash have several large by-pass channels to divert the mud from below to above the wash cups while running in hole to prevent surge effects. As a result, the tool can easy run in hole, and the tripping speed is only dependent of the TCP gun's limitations or the rig itself.

Wash cups are located above and below the wash tool to isolate and seal off a short section of the casing during the washing process. The distance between the wash-cups are designed to isolate 1 ft. of casing while washing. As a result, 12 inches/12 perforations are washed in one continues motion.

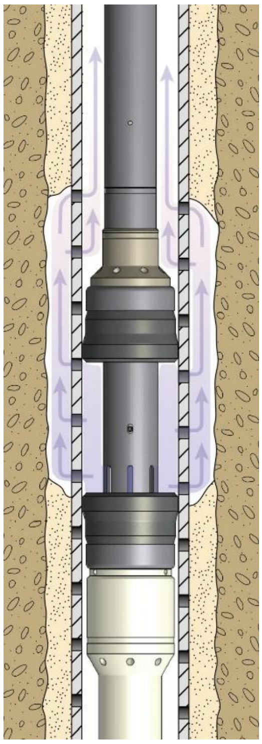


Figure 31 – HydraWash tool (35)

The wash cups have a larger outer diameter than the inner diameter of the casing to assure best possible isolation during washing. The elastomer material of the wash cups allows them to get compressed and squeezed when run in hole. After washing, the wash tool is disconnected, and the wash cups is used to seal off the well and acts as a foundation for the following cement operation.

11.2.4 HydraArchimedes

The HydraArchimedes tool is connected directly above the wash tool (either HydraWash or HydraHemera) and is developed to enhance the quality of the cross sectional plug.

The HydraArchimedes acts as a spatula, and is mechanically displacing cement out through perforations by use of helical rubber blades. The blades also act on the cement hydraulically by generating high and low pressure regimes which contributes in the displacement.

Each HydraArchimedes tool treats 25 m of perforations, hence at least two HydraArchimedes tools are necessary if the interval to be treated is longer than a drill pipe stand. As the interval is cemented the drill pipe is pulled out of hole. When disconnecting a stand, the pressure is bled-off and the cement U-tubes, hence no more pumping of cement is possible. Therefore at least two HydraArchimedes tools are necessary to cement a 50 m perforated interval when pulling out 30 m of drill pipe.

Figure 32 – HydraArchimedes tool (37)

11.2.5 The Operation

Once the HydraWash assembly is lowered to the desired depth, the perforation guns are fired and holes are created into the annulus. After the TCP gun have fired, it will automatically disconnect and be left in the well. If the well configuration or rat hole is insufficient, the guns have to be POOH, and the operation is performed in a dual trip configuration.

After the perforation sequence is completed the assembly is positioned at the upper area of the perforations. A ball is dropped to stop circulation through the washing tool and a sleeve shifts to direct the fluid flow between the wash cups. The washing starts in a top-down direction while flow is directed through the perforations and into the annular space. A suitable washing fluid is pumped down and is forced with high velocity into the annulus to effectively wash and circulate out various particles, deposits, filter cake, old mud, drill cuttings and cement residues.

The diameters of the perforations are designed to generate backpressures between 55 to 75 psi when pumping through the perforations. During the operation, pressure readings are used to control the washing process. At the onset of the washing process, high pressures readings are observed in the washing fluid as particles in the annulus will make resistance against fluid flow. Gradually, as particles are circulated out and the perforations are opened, the flow rate will increase and the pressure drops. The wash cups will not be moved to a new position until the pressure stabilizes. Figure 33, presents a typical washing pressure curve during a washing sequence. High pressure readings indicate fluids restrictions, while a decrease in pressure indicates that the annulus and perforations are opened and debris is removed.

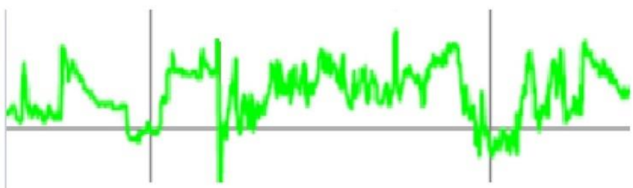


Figure 33 – Typical pressure washing curve (36)

When the washing tool has reached the bottom perforations, the washing process is repeated in a bottom-to-top direction while pumping at the maximus loss-free rate. The maximum loss-rate is the circulation pressure which equals the fracture pressure, and determines the maximum washing fluid rate. This rate is obtained during simulations during a pre-job planning phase.

Once the cement annulus has been fairly cleaned, the wash tool is lowered to the bottom of the perforations, and a spacer fluid is pumped between the wash cups into the annular space.

The wash tool is positioned below the perforations and a second ball is dropped to disconnect the wash tool from the cement stinger. The wash cups have sufficient contact force against the casing to function as a base for the cement plug.

To clean the wellbore for any residual materials, the cement stinger is pulled to the top of the perforations and the string is rotated at 100 to 120 RPM while pumping at maximum loss dree rate. Cement is then pumped through the cement stinger and a balanced cement plug is set. Rotation of the arckimedes tool forces the cement through the perforations, as the assembly is slowly POOH.

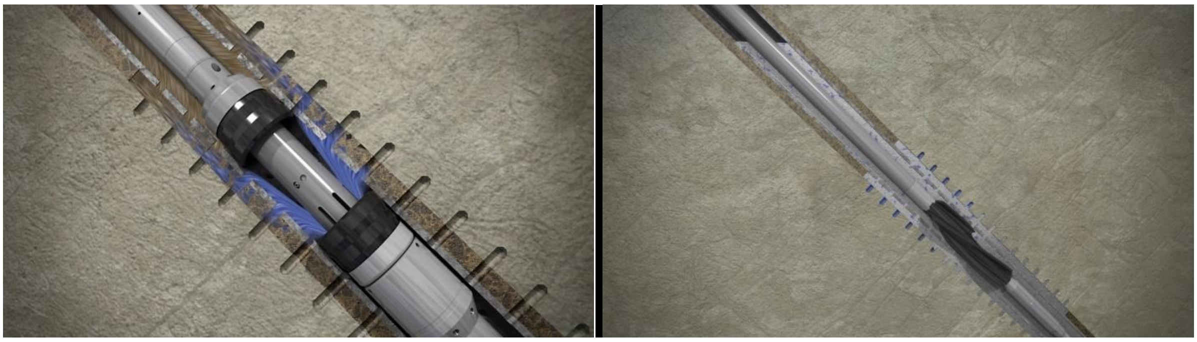


Figure 34 – (Left) Hydrawash. (Right) HydraArchimedes tool force cement into the annulus (37)

11.2.6 Trach records

Since HydraWell performed their first P&A job in 2010 with the PWC method, a total of 146 jobs have been executed. (19.02.2016). About half or 74 of these jobs have been executed with the HydraWash system. In table 7 the amount of plugs set pr. year with the HydraWash system is presented. Table 8 presents in which casing size the plugs were set. The HydraWash system had its peak in 2012, were most jobs were performed. As the HydraHemera system was introduced in 2013, the amount of jobs performed by the HydraWash system has gradually been reduced.

Table 7 – Amount of plugs set per year with the HydraWash system (37)

Year	Amount of plugs
2010	2
2011	17
2012	31
2013	12
2014	10
2015	2
2016	0

Table 8 – Respective casing size plugs have been placed in (37)

Casing type	Amounts of plugs
7”	4
9 5/8”	55
9 7/8”	7
10 3/4"	5
11 3/4"	1
13 5/8”	2

11.2.7 Experiences & problems

One of the drawbacks with the HydraWash is the large diameter of the washcups. During perforation small sharp burrs are created on the inside wall of the casing caused by backfiring of steel. The perforation shots deform the casing, leaving behind a solid mass of steel on the outside and inside of the perforation hole, known as burrs. The sharp metal edges of the burrs are particularly damaging for the washcups while moving up and down during the washing process.

Statoil experienced worn out washcups on the HydraWash tool during plugging of two well at Statfjord in 2012 (3). Consequently, unnecessary time was spent for tripping in and out of the well to replace the washcups, and in addition an extra run had to be done to re-wash the interval.

Many wells on the NCS have a reduced inner diameter due to collapsed sections in the well. The HydraWash can in such cases have trouble to enter the well due to the large dimensions of the tool. The washcups have an outer diameter of 8.78", but there is a steel Thimble in connection with the washcups on the 9 5/8" washing tool which have an OD of 8.125". Since the washcups are made of flexible elastomer material and can be compressed, it is the large diameter of the steel which is causing problems when run in hole. This makes it difficult for the HydraWash to enter wells that has reduces inner dimeter.

The HydraHemera system was developed to remedy or reduce at least one of the drawbacks experienced by the HydraWash system.

Under development of the HydraHemera another issue was encountered. The aim of the HydraHemera was to enable plugging of a well across multiple annuli, but it turned out that the HydraWashing tool for cleaning before plugging, was not suitable for cleaning a well with more than one annuli in a satisfactory manner. When cleaning two pipe bodies that are placed substantially concentrically, it was revealed that it was difficult to remove any residual cement or even clean satisfactory when no material was present.

If the washing process is not done satisfactory, the cement plug might be contaminated, and the cement plug may fail. To address the issue, a new washing tool was developed. This tool is described in the following chapter.

11.3 The HydraHemera system – Second generation PWC tool

HydraWell has developed a second generation system which utilize the PWC method. This system was primary developed to enable plugging of a well across multiple annuli. However, as stated above, the HyrdaWash was not suitable for cleaning a well with more than one annuli, so a new washing tool was developed. This led to the development of the HydraHemera Jetting Tool. The new washing tool was also designed to eliminate some of the drawbacks with the HydraWash tool. This also led to the development of the HydraHemera system for single casing, where the new washing tool is an integrated part of the system.

Although the HydraHemera system shares design similarities with the HydraWash system, there are some differences. The HydraHemera system for both double and single casing will be described below.

11.3.1 The HydraHemera system – Double Casing

The HydraHemera system for double casing consist of a single run assembly containing a bullnose with circulation, the HydraHemera Jetting tool, the HydraHemera Cementing tool, and the Archimedes cementing tool.

Before the assembly is run, a EZSV is set as foundation inside the casing, as the tool does not include an integrated disconnect plug. As this is completed, the HydraKraos and a TCP gun is run, and last the HydraHemera assembly is run to wash and set the cement plug. The HydraKratos is only run if there is a need for a foundation for the cement to be placed inside the annuli.

11.3.1.1 HydraKratos

Before running the HydraHemera it may be necessary to run the HydraKratos if there is no annular cement in either of the annuli to ensure a solid base for the coming annulus cement barrier. The HydraKratos is run just below a TCP perforating gun dressed with big holes' chargers.

Once the TCP gun is positioned in the desired P&A area, with the HydraKratos just below, a ball is dropped to activate the tools. The perforation guns are fired and the holes are as large and tightly spaced as both casings will allow. At the same time the HydraKratos is exploded to ensure a base for the cement plug in the inner and outer annulus. The energy from the explosion is calibrated to expand both casings, ensuring a casing to formation wall fit, as shown in figure 35. The tools will then be POOH and the HydraHemera will be RIH.

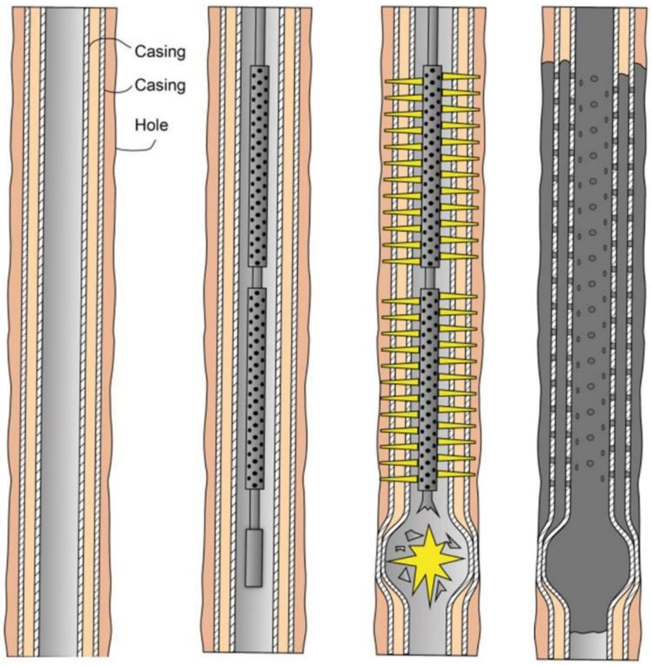


Figure 35 – HydraKratos and TCP guns (34)

11.3.1.2 HydraHemera

After the perforation sequence is completed, with or without the HydraKratos, the tools are POOH, and the HydraHemera is run in hole to the top of the perforations. The HydraHemera have a bullnose at the bottom of the assembly which allows for circulation while running in hole.

Above the bullnose is the HydraHemera Jetting Tool. Once the tool is in position, a ball is dropped to activate the cleaning nozzles. The washing starts in a top-down direction while clean mud is pumped down to wash and clean out debris, old mud, barite and old cuttings in the annuli behind the perforated casings. The mud is directed though nozzles, exiting the jetting tool as high energy jets. When the jets have reached the bottom perforations, the washing process is repeated in a bottom-to-top direction.

Figure 36 – From top to bottom: HydraHemera cement valve, HydraHemera Jetting tool, and bull nose (34)

The nozzles on the jetting tool are positioned at irregular angles and are engineered for an optimal configuration and exit velocity. The jets penetrate and clean the annulus space between the casings and the formation. The jets are deflected between the different annuli, thoroughly cleaning all voids and cavities behind the multiple perforated casings.

Once the annulus space has been cleaned, the jetting tool is lowered to the bottom of the perforations, and a spacer fluid is pumped through the jetting tool into the area. A second ball is dropped to activate the cementing nozzles in the HydraHemera cementing tool which is located above the jetting tool.

The cementing tool features four nozzles with larger diameter than the jetting tool to avoid cement dehydration and plugging of the nozzles. A cement valve in the tool is activated by pressure and cement is sprayed through the nozzles to reach all annuli with cement. Cement flows through the perforations and rotation of the Archimedes tool forces more cement through the perforations, ensuring a uniform plug in the cross section.

The cement valve in the HydraHemera cementing tool has a valve function to avoid "u-tubing" while disconnecting a stand. As a stand is disconnected, the pump pressure is bleed off and the valve closes. This eliminated another drawback with the HydraWash, and makes it possible to pump more cement after disconnecting a stand. This also eliminates the possibility to contaminate the cement during a disconnect.

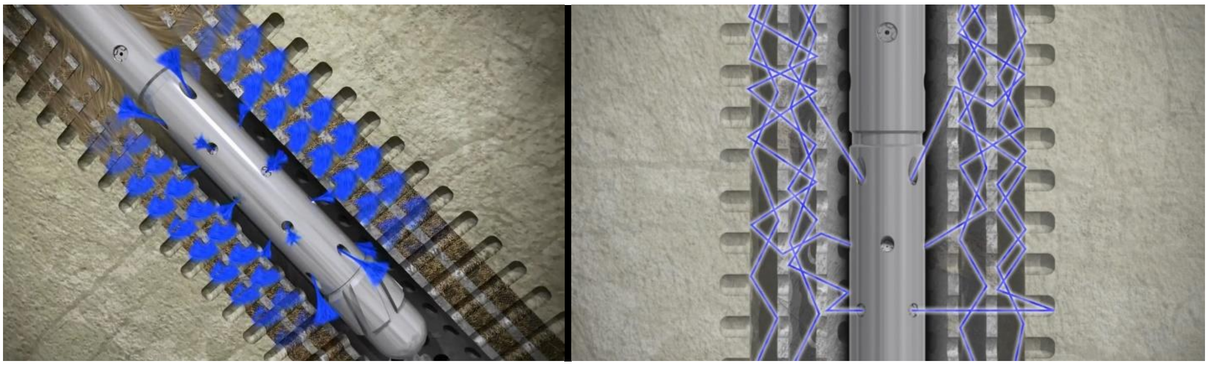


Figure 37 – HydraHemera Jetting tool washing two annuli (34)

11.3.2 The HydraHemera system – Single Casing

The HydraHemera system for single casing consist of a single run assembly, containing TCP gun with automatic disconnect, the Internal Cement Foundation (ICF) tool with disconnect, the HydraHemera Jetting Tool, the HydraSpray Cementing Valve, and the HydraArchimedes cement insurance tool.

The HydraHemera system for single casing have the same TCP gun with disconnect as explained for the HydraWash. The TCP gun are positioned in the P&A are, and activated by a ball drop firing head. After firing the assembly is automatically dropped and left in the well, if possible.

Since the HydraHemera utlilizes the HydraHemera jetting tool for washing, there are no wash cups to be disconnected to function as a base for the cement plug. To address the issue, the HydraHemera assembly contains an ICF tool. Once the ICF is in the correct position a ball is dropped and the ICF is disconnected forming a base in the well for the upcoming cement operation.

The jetting tool have some advantages over the HydraWash tool as the jetting tool has a smaller OD and can enter slightly collapsed wells and there will be no problems with worn out washcups. It will however not be possible to monitor the pressure while washing, but as the jetting tool features nozzles which are positioned at irregular angles, it will clean the annulus better than the HydraWash tool.

Once the ICF is in place, the tool string is pulled up to the top perforations. A ball is dropped to direct the flow through the jetting tool, and the washing process can begin. The washing starts in a top-down direction, and then back up again. The energized fluid exiting the nozzles is engineered to ensure that proper kinetic energy remains in the jets at the furthest distance at the formation wall. The annular space outside the casing and formation is then cleaned.

Figure 38 – (Left) Internal Cement foundation (ICF). (Right) HydraHemera Jetting tool (34)

Once the annular space has been cleaned, the HydraHemera jetting tool is used to displace spacer fluid into the area. A new ball dropped diverts the flow through the Hydra cementing valve, and cementing can begin. Cement is injected through the perforations to fill both the annular and internal volumes. Rotation of the Archimedes tool forces more cement through the perforations ensuring a uniform plug in the cross section. The HydraHemera spray cement vale also have the function to avoid “u-tubing” while disconnecting a stand.

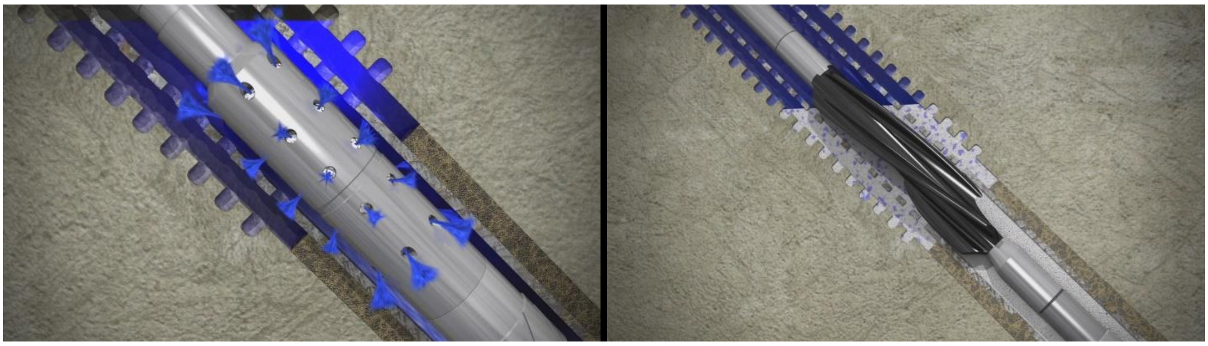


Figure 39 – (Left) HydraHemera Jetting tool injecting spacer fluid. (Right) HydraArchimedes forcing cement into the annuli (34)

11.3.2.1 Trach records

Since HydraWell introduced the HydraHemera system in 2013, the system has been used to perform 72 P&A jobs (19.02.2016). The HydraHemera system have reduced and eliminated some of the drawback with the HydraWash system, and is now the preferred system for plugging a well using the PWC method.

Table 9 presents the amount of plugs set pr. year with the HydraHemera system, while table 10 presents in which casing size the plugs were set. The HydraHemera system for double casing have only been performed nine times to date. This is because it is challenging to verify a continuous cement plug over the entire cross section. Verification is described in the following section.

Table 9 – Amount of plugs set per year with the HydraHemera system (34)

Year	**Amount of plugs**
2013	5
2014	21
2015	35
2016	11

Table 10 – Respective casing size plugs have been placed in (34)

Casing type	Amounts of plugs
7”	1
7” x 9 5/8”	4
8 5/8” x 10 3/4"	3
9 5/8” x 10 3/8"	2
9 5/8”	51
9 7/8”	3
10”	5
10 3/4"	2
13 3/8”	1

11.3.2.2 Verification

The PWC method presents a relatively new technique for placing a cement plug, and needs to be verified and approved. The well barriers placed with this method needs to be verified to ensure that the barriers are effective and fulfils the requirements stated in NORSOK D-010.

HydraWell recommends new customers or operators using the method on new fields to drill out the plug and log the annular cement. Operators would then confirm if the annular cement is of good quality before the well is abandoned. The plug should also be drilled out to enable evaluation of the annular cement if operational problems which could affect the integrity of the plug were encountered during the operation.

To verify the annular cement, a drill bit is lowered into the well, and the cement plug inside the casing is drilled out. Once the drilling sequence is completed a cement evaluation tool is run in the well. The annular cement is usually logged with CBL and USIT logs. These logs were described in section 5.1 and 5.2 respectively. The logs are then compared to existing post-logs to evaluate annular plug quality. Afterwards the internal casing plug will be re-cemented to regain the cross sectional plug integrity.

Once the final cement plug is in place, it will be tagged and pressure tested as described in section 4.7.1.

Operators who have gained experience and good results with the PWC method will only verify the plugs by pressure testing. More time is then saved as additional drilling, logging and tripping is eliminated.

Positive pressure tests are performed for all plugs as this test is easier to perform then a negative pressure test. In a positive pressure test, the pressure inside the casing above the plug is pressurized. This is easy to accomplish as there normally is heavy fluids already present in the well.

There is however a challenge to verify the plugs set in two annuli with the HydraHemera system for dual casings. The logging technology currently in use generally allows for logging behind only one casing. It is therefore not possible to reach the outermost annuli to verify whether the annular cement is of good quality. To verify if the HydraHemera plug set in two annuli seals, negative pressure test is performed. In this case the pressure inside the casing is reduced by displacing the well to a light fluid. The well head pressure (WHP) is monitored to check for any leaks. The problem with this is however how long the pressure must be stable before the plug can be approved.

11.3.2.3 Post logs

Plugs set with both HydraWash and HydraHemera system have been drilled and logged 39 times. For the HydraWash system all plugs were approved, but six plugs had some issues with the cement in the annulus. For the HydraHemera system all plugs have been approved without any issues.

Table 11 – Logging record of HydraWash and HydraHemera (34)

	Size	Type	Results
2010	9-5/8”	HydraWash	USIT/CBL
2011	9-5/8”	HydraWash	USIT/CBL
2012	9-5/8”	HydraWash	Approved (some issues)
	9-5/8”	HydraWash	Approved (some issues)
	9-5/8”	HydraWash	Approved (some issues)
	9-5/8”	HydraWash	Approved (some issues)
	9-5/8”	HydraWash	USIT/CBL
	9-5/8”	HydraWash	USIT/CBL
	9-7/8”	HydraWash	USIT/CBL
2013	13-5/8”	HydraWash	Approved (some issues)
	13-5/8”	HydraWash	Approved (some issues)
	10-3/4”	HydraWash	USIT/CBL
	10-3/4”	HydraWash	USIT/CBL
	10-3/4”	HydraWash	USIT/CBL
	9-5/8”	HydraWash	SBT
2014	9-5/8”	HydraWash	USIT/CBL
	9-7/8”	HydraWash	USIT/CBL

	9-7/8”	HydraWash	USIT/CBL
	9-5/8”	HydraHemera	USIT/CBL
	9-7/8”	HydraWash	USIT/CBL
	9-5/8”	HydraWash	USIT/CBL
	9-5/8”	HydraWash	USIT/CBL
	9-5/8”	HydraWash	USIT/CBL
	9-5/8”	HydraHemera	USIT/CBL
	9-5/8”	HydraHemera	USIT/CBL
	10-3/4”	HydraHemera	USIT/CBL
	10-3/4”	HydraHemera	USIT/CBL
	9-5/8”	HydraHemera	SBT
2015	9-5/8”	HydraHemera	SBT
	9-5/8”	HydraHemera	SBT
	10”	HydraHemera	IBS/CBL
	9-5/8”	HydraHemera	USIT/CBL
	9-5/8”	HydraHemera	IBS/CBL
	9-5/8”	HydraHemera	IBS/CBL
	9-5/8”	HydraHemera	SBT/CAST
	9-5/8”	HydraHemera	USIT/CBL
	9-5/8”	HydraHemera	USIT/CBL
2016	9-5/8”	HydraHemera	USIT/CBL
	9-5/8”	HydraHemera	USIT/CBL

11.4 NORSOK – Alternative method to establish a permanent well barrier

The newest revison of NORSOK D-010 includes a manual or flowchart for a alternative method to establish a permanent well barrier for wells with poor cement or no access to the last open hole section.

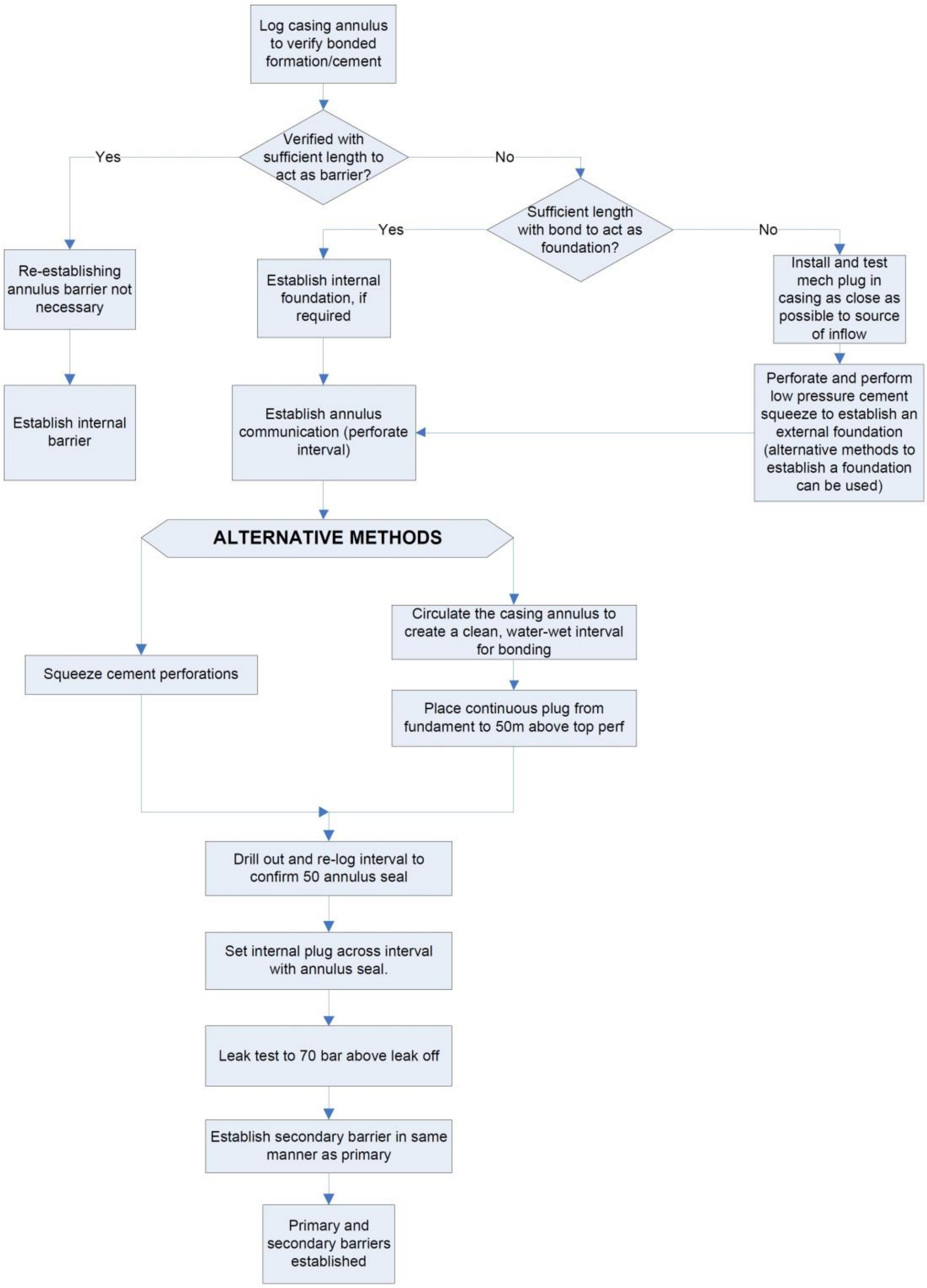


Figure 40 – Alternative method to establish a permanent well barrier (5)

12 Concepts & P&A technology in the future

12.1 Upward section milling

Section milling is conventionally performed in a downward direction by applying weight on the tool assembly. The weight is made of the drill string itself, or by including drill collars. The weight will force the assembly to progress through the pipe being milled. But forcing the assembly downwardly has a tendency to make the work string wobble, and in turn causing the cutters to worn out faster. The assembly is also subjected to high level of axial and torsional vibrations causing the cutters to wear and possible damage the assembly. This results in less pipe being milled before the cutters are required to be replaced. Further, since milling is performed in a downward fashion, cuttings or swarf, must be removed as they are created. If the generated swarf is not circulated out properly, the swarf can cumulate and potentially make the work string stuck. It is therefore critical to have a well formulated milling fluid, a proper flow rate and an optimal ROP to be able to circulate the swarf out of hole. In addition, the swarf brought to surface must be handled and taken care of before it is transported to shore.

To challenge the conventional section milling, another concept has been developed. The new concept involves performing section milling upwards. This is achieved by using tension to drag the assembly up, rather than using weight to push in down. This will obviously eliminate the need of heavy drill collars, but the greatest advantage is that all the swarf is left downhole. As summarized above and discussed in section 10.2.2, swarf is the root cause to many of the challenges associated with conventional section milling. Consequently, by leaving the swarf downhole, many of the problem can potentially be eliminated.

In the following are two variations of upward section milling presented. The first is based on a patent from the United States released in 2004 (38), where an apparatus for reverse section milling is described. The second is an upward section milling tool developed by a company called WestGroup.

12.1.1 Reverse section milling (38)

The concept of reverse section milling presented in the patent describes two different apparatus for milling a section of a casing in a well.

The first apparatus consists of a section mill with a stabilizer, an up-thruster tool, an anti-torque tool, and a downhole motor mounted to a work-string. To assist the cuttings moving downward, a spiral auger with a left hand twist can be positioned at the bottom of the work-string, below the section mill.

The second apparatus consist of the same section mill with a stabilizer used in combination with an up-thruster tool and a rotation work string. The same spiral auger can be positioned below the section mil.

The difference between the apparatus is that the first employs a downhole motor to rotate the mill, while the second is rotated by the work string itself. The first apparatus is also featured with an anti-torque tool to eliminate torque generated by the motor and to make the milling assembly stiffer. If the anti-torque tool is not utilized, the drillstring could torque up and reduce in length when the motor stalls. This would subsequently affect the milling tool blades, and cause them to quickly degrade. Apart from these differences, the operational procedure for both apparatuses is essentially the same.

In the following is a brief description of the tools and their working methodology, described by the order they are used in the operation. Figure 41 illustrates both apparatuses, and their respective tool components.

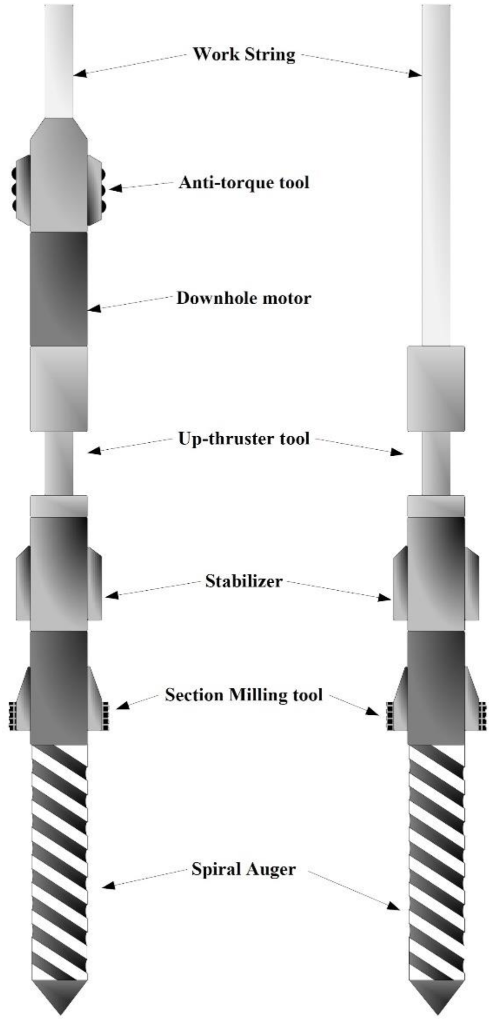


Figure 41 – Upward milling assembly (38)

12.1.1.1 Anti-torque tool

As with conventional section milling, the operation starts with the tool tripping into the hole to a desired depth, only this tool is positioned at the lower end of the milling window. If the motor is used to provide rotation, the anti-torque tool will be applied. The anti-torque tool is connected to the mud motor embodiment and is positioned at the top of the tool assembly. The anti-torque tool features a gripping mechanism which is actuated by a hydraulic pressure. As fluid is pumped into the tool assembly, gripping members are hydraulically displaced outwardly until they engage the casing wall. These gripping members are designed with teeth's, ridges, or ribs to grasp the casing wall. Although this prevents rotation of the tool itself, the gripping members can be configured with rolling devices, such as weels, to allow movement in a longitudinal direction or only in the uphole direction.

12.1.1.2 Up-thruster

The up-thruster is used to supply a constant upward force to the section mill, as the tension force imparted by the rig would be to irregular. Without the up-thruster the operator would have to be extremely careful to not overload the mill, if not the mud motor would stall out.

The up-thruster is a hydraulic cylinder pressurized by the mud flow which is pumped through a fluid flow path in the tool assembly. As the fluid flows through a nozzle in the section mill, a back pressure is created in the apparatus. This back pressure is in essence the mechanism which causes the up-thruster to lift upwardly. The pump pressure can be controlled to a such precision that the loading on the mill is very constant.

12.1.1.3 Section milling tool

The section milling tool employed is similar to conventional section milling tools. Pivotable arms are mounted in longitudinal slots in the tool body, and are held open by an upward moving wedge block. Pistons in the tool body are forced upward by hydraulic pressure, moving the wedge block upwardly against the arms. This supports the arms under heavy loading, and creates a maximized outward force on the cutting blades. In order to retract the arms, the tool can be featured with a ball drop deactivation mechanism. By applying pressure against the ball, the pistons can be drawn back, and the arms will retract.

12.1.1.4 Stabilizer

A stabilizer above the section mill are used to provide stability during the operation. The stabilizer arms are dressed with hard facing material and are extended stabilize the mill relative to the casing being milled. To provide stability throughout the operation, the arms are designed to extend at a fluid pressure lower than the pressure required to run the up-thruster.

12.1.15 Spiral Auger

The final component is a spiral auger, which is positioned at the bottom of the tool assembly. The spiral auger is basically a short drill collar dressed with left hand spiral ribs. The purpose of the spiral ribs is to force cuttings downwardly to prevent pack-offs around the mill.

12.1.2 SwarfPak

As mentioned, a concept of upward section milling has been invented by a company named West Group. West Group is based in Stavanger, Norway, and focus on developing step-change technologies for the petroleum industry. They have to some extend refined the method and apparatus proposed in the patent from 2004. They have developed a tool assembly named SwarfPak which is based upon the principle of upward milling. The SwarfPak introduces reverse flow principles (gravel pack), allowing the generated swarf to be left downhole. Figure 42 illustrates the how the upward milling process is expected to be performed by using the SwarfPak tool.

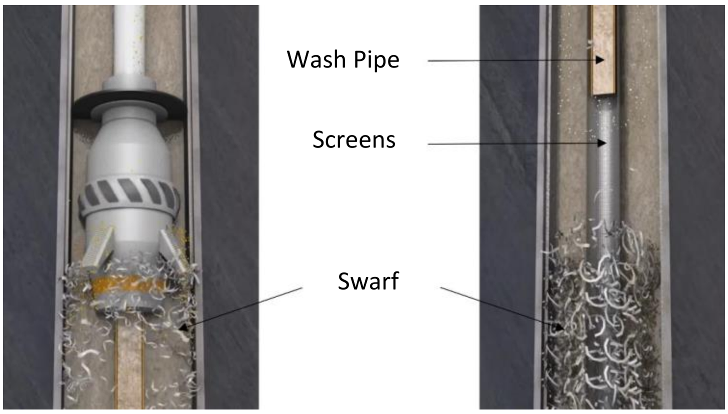


Figure 42 – Upward section milling by the use of the SwarPak tool (39)

West Group reports that the technical goal of the SwarfPak is to generate a milling speed in the range 18-30 m/hr or 60-100 ft/hr.

West Group also list the following as technical goals and benefits for the SwarfPak (39) (40):

- Upward milling leaves swarf down-hole
- Swarf size optimized and at a controlled and homogenous size

- Precise and ultrafast milling
- Increased satety – no swarf in BOP
- Eliminates swarf handling on surface
- Eliminates vibrations
- Milling of 50 m section in 1 run

The author could not get any detailed information about the SwarfPak due to lack of response form the company.

12.2 Plasmabit milling

12.2.1 The tool

Since 2013 has a company named GA Drilling led a joint industry project (JIP) to develop and commercialize a Plasmabit technology platform which provides groundbreaking drilling and milling tools. GA Drilling is currently focusing their technology on P&A, but their technology is in the prototype stage and are under development.

Instead of a conventional rotary contact drill, the plasmabit is based on a plasma generator, producing high temperature water steam plasma while spinning up to 800 rotations per second (48 000 rpm) (41). The generator uses an electrical arc which generates temperatures up to 5700 ˚C. The extreme temperature melts and disintegrates rock, steel, cement or any other material without direct contact.

The system is designed to be used with coiled tubing, which means it can be deployed from a light well intervention vessel (LWIV).

The tool consists of a fluid and power system (see figure 44), which is designed to deliver continuous inputs into the tool. The idea is to use an umbilical containing tubes for fluids delivery, electrical conduits and communication pathway. Sensors in the tool can provide real-time data acquisition of milled material through the communication pathway, providing the personnel with detailed information during the operation.

Furthermore, section milling with the plasmabit generates small swarf particles, as seen in figure 43. This eliminates many of the problems with conventional section milling, as stuck tools, and also helps to ensure integrity of the BOP.

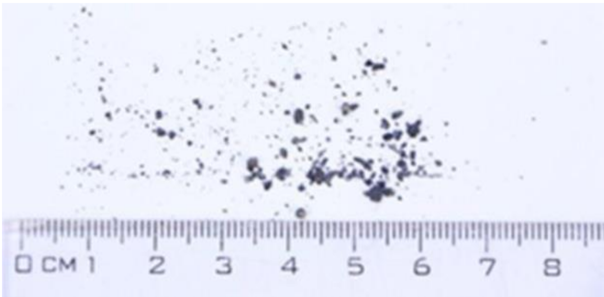


Figure 43 – Cuttings formed during testing (scale in centimeters) (42)

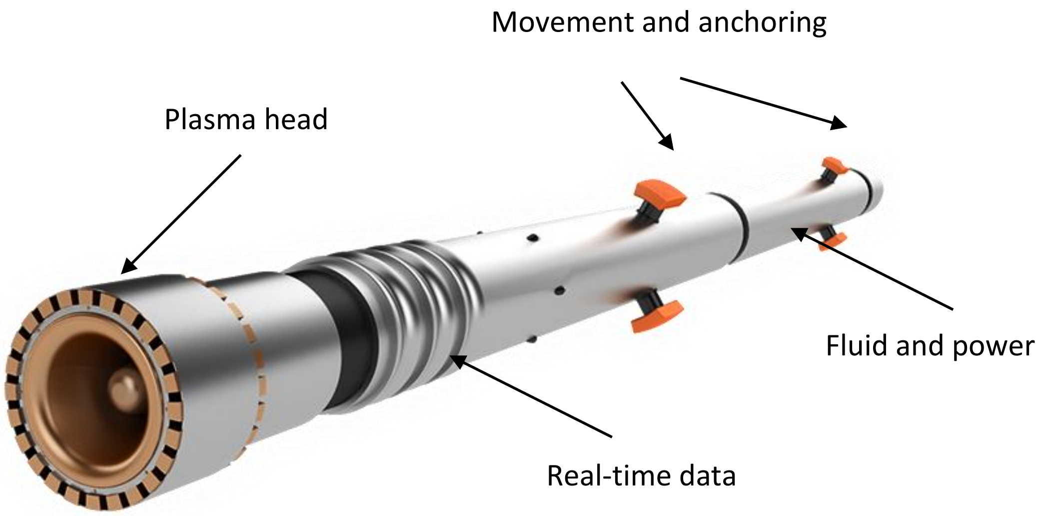


Figure 44 – Plasmabit tool (41)

A general operational procedure for P&A was described in section 8.3. The plasmabit tool can simplify this operation. As stated, the tool is designed to be used with coiled tubing, hence the tool should be able to operate through tubing. This eliminates the need to nipple down the XMT and nipple up the BOP. The tool can then be run through the tubing, and mill both tubing and casing in one trip. The operation can also be performed on a live well, eliminating the kill procedure. Figure 45 illustrates the operation where a section of tubing and casing is milled with the plasmabit.

12.2.2 The operation (43)

a) The tool is run though tubing into the desired depth where the plug should be set.
b) Once in position, the electric arc is ignited, plasma is created and the tool is run upwards while removing the tubing.
c) After the tubing is removed, the tool is run back to its initial position.
d) Again, the tool is run upwards, while removing casing and cement layers.
e) After tubing, casing and cement is removed, the tool is POOH, and the section is ready for cement plug setting.

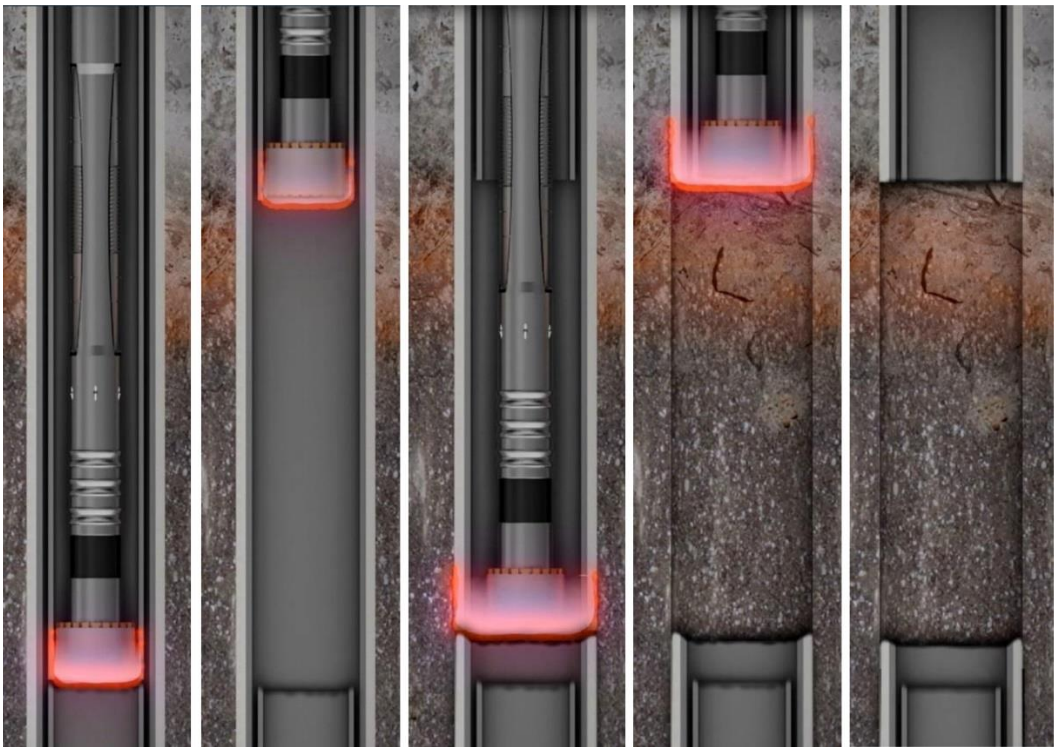


Figure 45 – Casing section milling of tubing and casing the plasma-based tool (43)

By using this procedure, leaders of the JIP claims that it should be possible to save 30-50 % overall time compared to conventional section milling. Figure 46 illustrates a comparison of the conventional and plasmabit P&A operational process with associated time consumption of the sequences in the operations. The operations are based on a North Sea case study where two sections needed to be milled and cement plugs set. It should also be noted that besides the simplification of the process, significant time savings could be obtained as the plasmabit is run on coiled tubing. This would result in less mobilization/demobilization time.

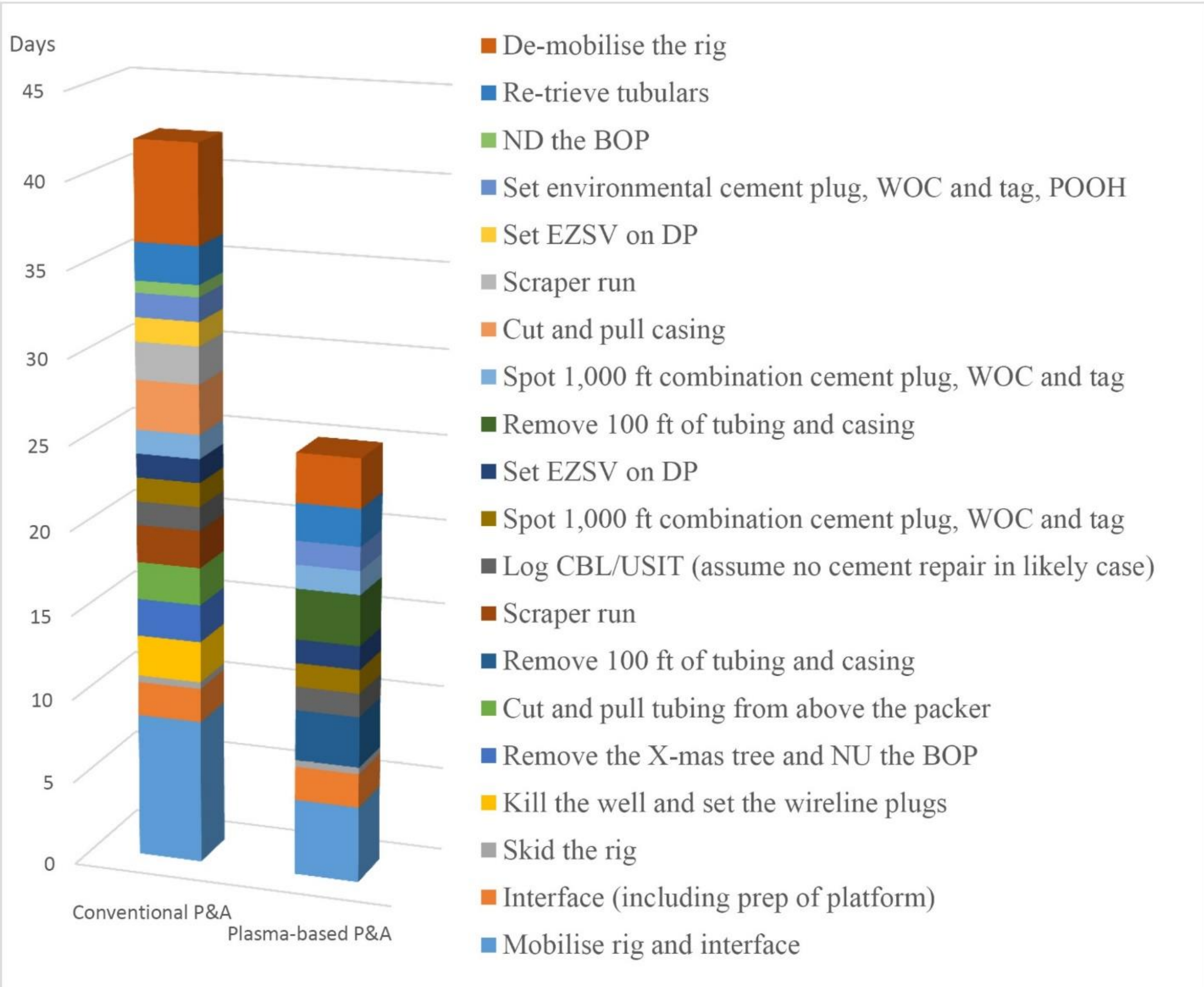


Figure 46 – Comparison of conventional and plasma-based P&A process on a North Sea Well (43)

Tests of the technology has been performed on several casing types under various process conditions. Tests have been performed in non-pressurized liquid environment with both water and brine and under high pressure environments in pressure chambers (42). As the functionality of the technology has been demonstrated over a limited range of conditions, the technology has now reached level 3 in the API 17N Technology Readiness Level (TRL). The next step is to reach level 4, by testing a full-scale prototype in its intended environment. An onshore filed test is intended this year, and the aim is to prove the whole system in an offshore filed test in the North Sea by 2017.

13 Case study

This case study will compare the conventional P&A technology of section milling with the PWC technology from HydraWell. Data from three individual P&A operations are presented. Two of the P&A operations are good examples of section milling operations, and the last is a good example of a PWC operation. All operational steps are presented and will be compared with respect to time and scope.

The data used in this case study is provided by an operator on the NCS, but wants for all intents and purposes to remain anonymous. Consequently, field and well names will not be mentioned. Therefore, will the well names be referred to as “SM-1” and “SM-2” where section milling was applied, and “PWC-1” where the PWC technology was applied.

All three operations were performed at similar environments at the same field via a jack-up platform. Consequently, are these three cases considered comparable.

It is important to note that there are always uncertainties associated with well operations. Hence, incident or unexpected events may affect the primary operational plan resulting in adjustments and changes to the plan. Incidents affected the operational plan for both wells were section milling were applied. This is further described below.

Objective of the P&A operations

- SM-1 and SM-2 wells
    - Reservoir barrier:
      Section mill 165 ft. of 9 7/8 in. casing, underream open hole and set balanced cement plug.
    - Secondary barriers:
      Section mill 330 ft. of 9 5/8 in. casing, underream open hole and set balanced cement plugs.
    - Surface barrier:
      Cut 9 5/8 in. casing, pull 9 5/8 in. casing, set balanced cement plug.

- PWC-1 well
  - Reservoir barriers:

    Set two cross sectional barriers in 9 5/8 in. casing with HydraHemera PWC tool.

    Two 165 ft. plugs in combination – 333 ft. plug
  - Secondary barriers:

    Set two cross sectional barriers in 9 5/8 in. casing with HydraHemera PWC tool

    Two 165 ft. individual plugs
  - Surface barrier:

    Cut 9 5/8 in. casing, pull 9 5/8 in. casing, set balanced cement plug above 9 5/8 in. stump.

13.1 Operational procedure

13.1.1 Operational procedure for well SM-1

The operational sequence with the associated time duration of each sequence is presented in the table below. The whole operation lasted for 37,93 days.

Table 12 – Operational procedure for well SM-1

	Well SM-1		
Stp.	**Track name**	**Duration**	**Duration**
		[hrs]	[days]
1	Skid Rig to Well SM-1	2,25	0,09
2	Rig Up on Well SM-1	9,25	0,39
3	Pull DHSV	1,5	0,06
4	Cut Tubing and Kill Well	47,5	1,98
5	Nipple Down X-mas Tree	6,5	0,27
6	NU 13 5/8" riser and 18 3/4" BOP	21,75	0,91
7	Pull Tubing	35,25	1,47
	Install Reservoir Barrier	**255,75**	**10,66**
8	Set 9 7/8" EZSV above Tubing Cut	62	2,58
9	Section Mill 165 ft of 9 7/8" Casing	128,5	5,35
10	Underream Open Hole	28,25	1,18
11	Set Balanced Cement Plug	37	1,54
	Install Secondary Barrier	**365**	**15,21**
12	Set 9 5/8 EZSV and cut 9 5/8" casing	33,5	1,40
13	Section Mill 330 ft of 9 5/8" Casing	153,75	6,41
14	Underream Open Hole	28,75	1,20
15	Set Balanced Cement Plugs	149	6,21
	Install Surface Plug	**107,75**	**4,49**
16	Remove Secondary Packoff	9,75	0,41
17	Pull 9 5/8" Casing Tieback to surface	85,25	3,55
18	Set Balanced Cement Plug	12,75	0,53
19	ND BOP/Riser	57,75	2,41

13.1.2 Operational procedure for well SM-2

The operational sequence with the associated time duration of each sequence is presented in the table below. The whole operation lasted for 31,43 days.

Table 13 – Operational procedure for well SM-2

	Well SM-2		
Stp	**Track name**	**Duration**	**Duration**
		[hrs]	[days]
1	Skid Rig to Well SM-2	2,5	0,10
2	Rig Up on Well SM-2	11,75	0,49
3	Pull DHSV	1,75	0,07
4	Cut Tubing and Kill Well	30,25	1,26
5	Nipple Down X-mas Tree	8	0,33
6	NU 13 5/8" riser and 18 3/4" BOP	20,5	0,85
7	Pull Tubing	42,5	1,77
	Install Reservoir Barrier	**253,75**	**10,57**
8	Set 9 7/8" EZSV above Tubing Cut	34,25	1,43
9	Section Mill 165 ft of 9 7/8" Casing	155,75	6,49
10	Underream Open Hole	31,5	1,31
11	Set Balanced Cement Plug	32,25	1,34
	Install Secondary Barrier	**310,25**	**12,93**
12	Set 9 5/8" EZSV	48,5	2,02
13	Section Mill 330 ft of 9 7/8" Casing	148	6,17
15	Underream Open Hole	70,75	2,95
16	Set Balanced Cement Plugs	43	1,79
	Install Surface Plug	**39,75**	**1,66**
17	Cut 9 5/8" casing at 2000 ft	11	0,46
18	Remove Secondary Packoff	8	0,33
19	Pull 9 5/8" Casing to 2000 ft	11,5	0,48
20	Set Balanced Cement Plug	9,25	0,39
21	ND BOP/Riser	33,25	1,39

13.1.3 Operational procedure for well PWC-1

The operational sequence with the associated time duration of each sequence is presented in the table below. The whole operation lasted for 18,12 days.

Table 14 – Operational procedure for well PWC-1

	Well PWC-1		
Stp	**Track name**	**Duration**	**Duration**
		[hrs]	[days]
1	Skid Rig to Well PWC-1	56,5	2,35
2	Pull Tubing	40,25	1,68
3	R/U and Run Cement/Caliper log in 9/58" Casing	15,5	0,65
	Set Reservoir Plugs	**150,75**	**6,28**
4	Set 1st and 2nd Reservoir Plug with HydraHemara	70,78	2,95
5	(Drill Reservoir Plugs, log and set Balanced Plug)	(80)	(3,33)
6	Drill Reservoir Plugs	40	1,67
7	Log Perforated Interval	12	0,50
8	Place Balanced Cement Plug	28	1,17
	Set Secondary Plugs	**91,5**	**3,81**
9	Set 1st Plug with HydraHemara	47,75	1,99
10	Set 2nd Plug with HydraHemara	43,75	1,82
11	Remove 9 5/8" Casing	29,5	1,23
12	Clean out 13 3/8" Casing	13	0,54
13	**Set Surface Plug**	**13,5**	**0,56**
14	ND Riser and BOP	24,25	1,01

13.2 SM-1 and SM-2

13.2.1 Contingencies during the operation

The operational sequence for well SM-1 and SM-2 were almost identical. From figure 47 and 48 it can also be perceived that the time distribution of the various operational sequences for both wells were very similar. However, the total operation for well SM-1 lasted 6,5 days longer than the operation on well SM-2.

Different contingencies were encountered on both wells during the operation. Issues with pack-off occurred on multiple occasions during the installation of the reservoir barrier in well SM-1. As a result of poor swarf transport, lots of time was spent on pulling the pipe out of hole to try to avoid stuck pipe. Attempts to remove the excessive swarf then happened through circulation. Considerable amount of time was also used on stuck pipe and fishing operation due to loss of equipment. During the installation of the secondary barrier pack-off was not a big of an issue. There were however some problems with loss of equipment's which altered the operation, and resulted in more time consumption when setting the cement plugs.

Pack-off and stuck pipe was also a problem during the installation of the reservoir barrier in well SM-2. The installation of the secondary barrier occurred without major problems. There were some acceptable issues with the ECD and worn equipment, and some minor problems with under-reaming of the open hole. All issues were solved successfully.

13.2.2 Time-consumption

Further investigation of figure 47 and 48, displays that most of the time were used on setting the barriers and cutting and pulling the tubing. Of the total time consumption, installation of the reservoir and secondary barriers accounted for 68,2 % and 74,77 % for well SM-1 and SM-2, respectively. That means that these operations account for most of the time consumption, and consequently have the largest effect on the cost.

The most effective way to reduce cost exposure is by reducing the total number of hours involved in each sequence of the P&A operation. But it is important to note that this have to be accomplished without compromising safety and the quality of the operation.

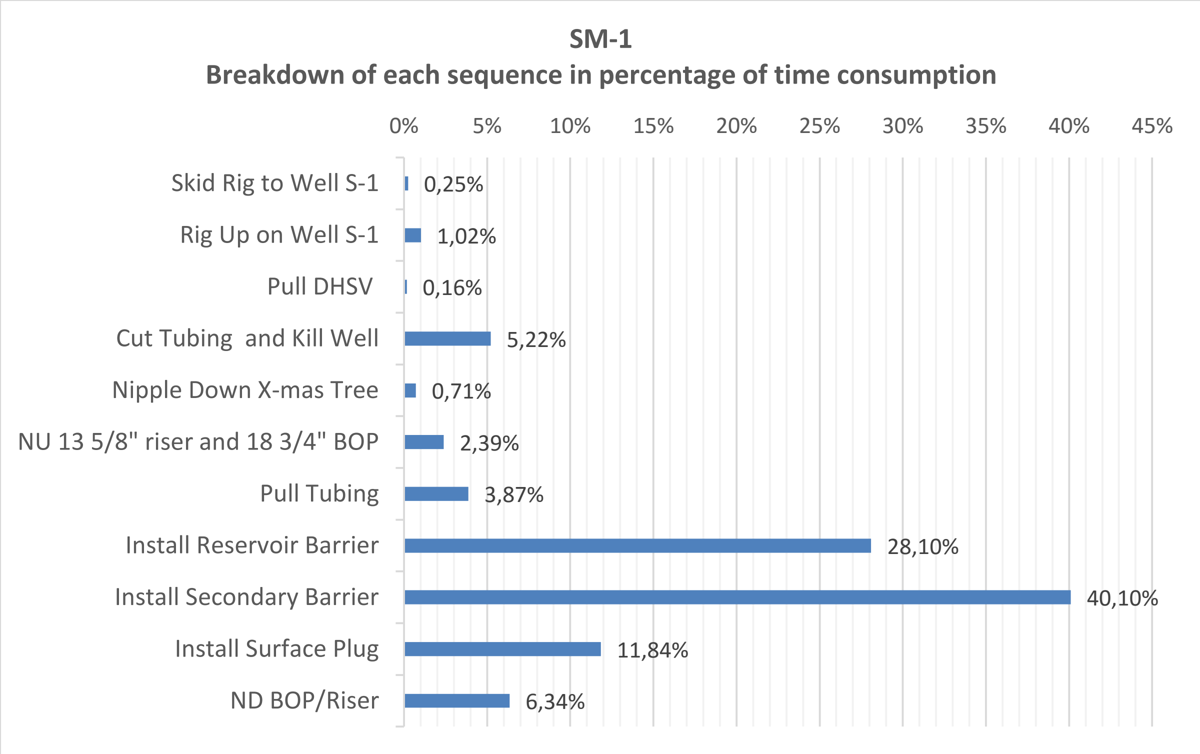


Figure 47 – Breakdown of each sequence in percentage of time consumption for well SM-1

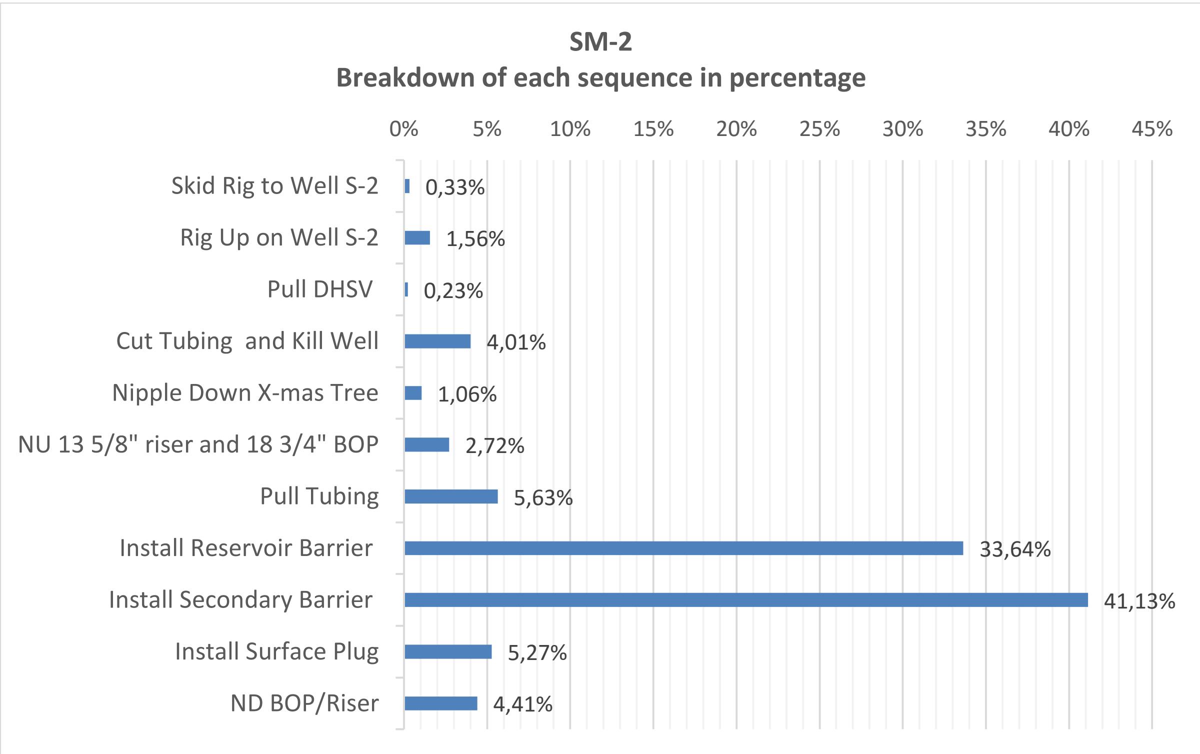


Figure 48 – Breakdown of each sequence in percentage of time consumption for well SM-2

Taking a deeper look into time consumption of the installation of the reservoir and secondary barriers, figure 49 and 50, reveals that the section milling and the following under-reaming of the open hole is the most challenging part of the installation. The section milling and under-reaming represents 37,27 % and 53,83 % of the total time consumption of the operation on well SM-1 and SM-2, respectively. This means that 14,14 days of the total operation was spent on milling and under-reaming on well SM-1 and 16,92 days on well SM-2. This is undesirable amounts of time, and shows that by eliminating or reducing time spent on milling and under-reaming one can potentially reduce a lot of rig-time and subsequently cost. Milling the casing also requires numerous trips into the hole and out of the hole. Time spent on tripping aids no progress to an already time consuming and expensive operation. Therefore, by reducing the number of trips in and out of the hole, cost could be reduced.

In well PWC-1, the PWC technique from HydraWell was used. This method eliminates many of the challenges of section milling operations. In section 13.4 is a comparison of the three cases conducted.

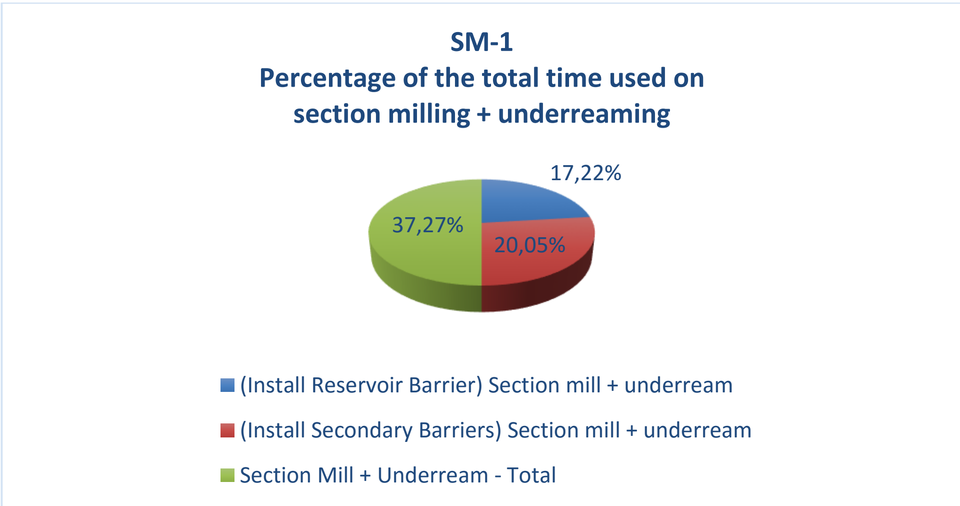


Figure 49 – Percentage of the total time used on section milling and underreaming for well SM-1

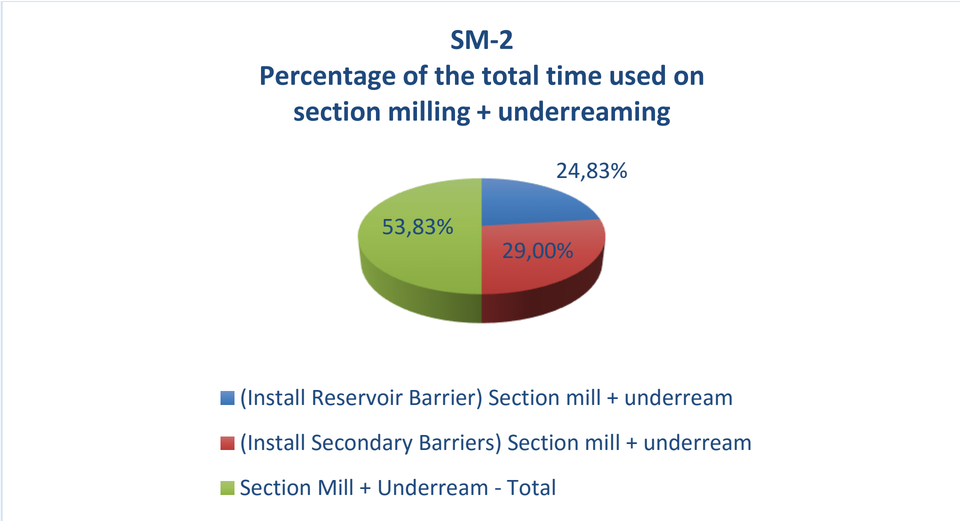


Figure 50 – Percentage of the total time used on section milling and underreaming for well SM-1

13.3 PWC-1

The time breakdown of the main operational sequences of the PWC operation is presented in figure 51. As can be seen from the figure is still a large amount of time spent on setting the reservoir and secondary barriers, and pulling the tubing. However, over half of the time spent on setting the reservoir barrier was used on drilling out the plug to confirm if the annular cement was of good quality before the well was abandoned. Additional time was then used on drilling out the plug, logging the annular cement, and re-cementing to regain the cross sectional plug integrity.

This is not necessary for operators who have gained experience and good results with the method, and does only need to verify the plug by pressure testing, tagging and load testing. More time is then saved as additional drilling, logging and tripping is eliminated.

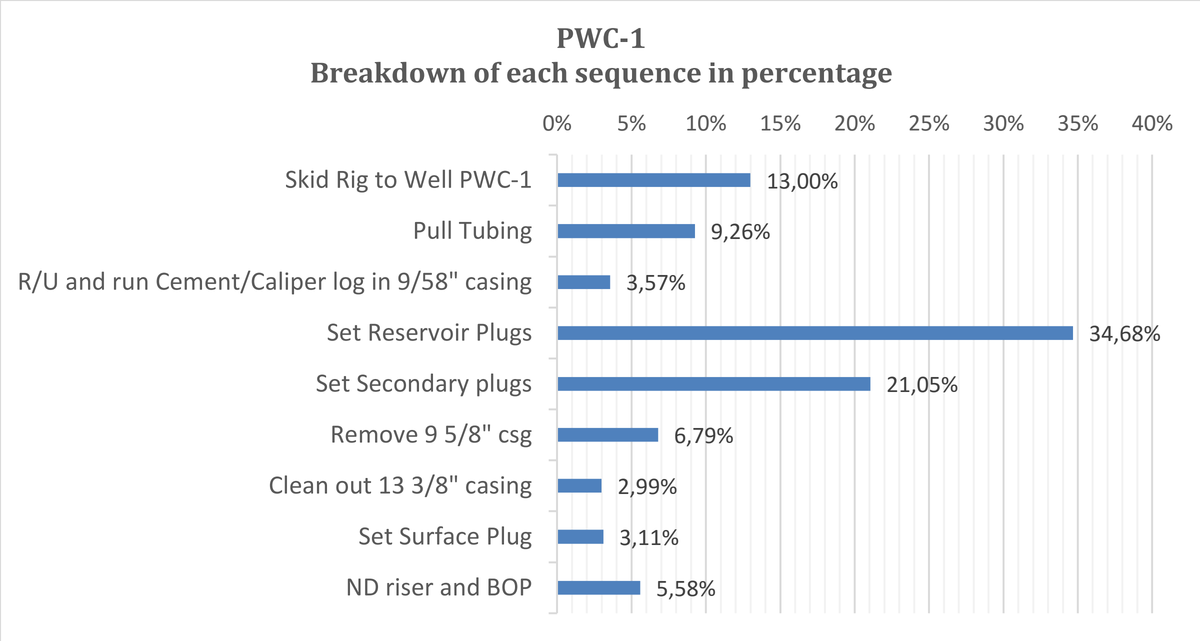


Figure 51 – Breakdown of each sequence in percentage for well PWC-1

13.4 Time comparison of the three cases

In figure 52 a diagram is presented showing the total time to install the reservoir barrier(s) and the secondary barriers for well SM-1, SM-2 and PWC-1. As can be seen from the figure was the time consumption of the plugging operation sufficiently less for the well where the PWC technology where employed. Comparing the diagram revels that the installation of the reservoir and secondary barriers for well PWC-1 were 15,77 days and 13,41 days less than in well SM-1 and SM-2, respectively. This shows that the HydraHemera PWC tool from HydraWell introduces a significant time-saving for P&A operations. For each day the operation can be reduced due to increased efficiency, cost is saved.

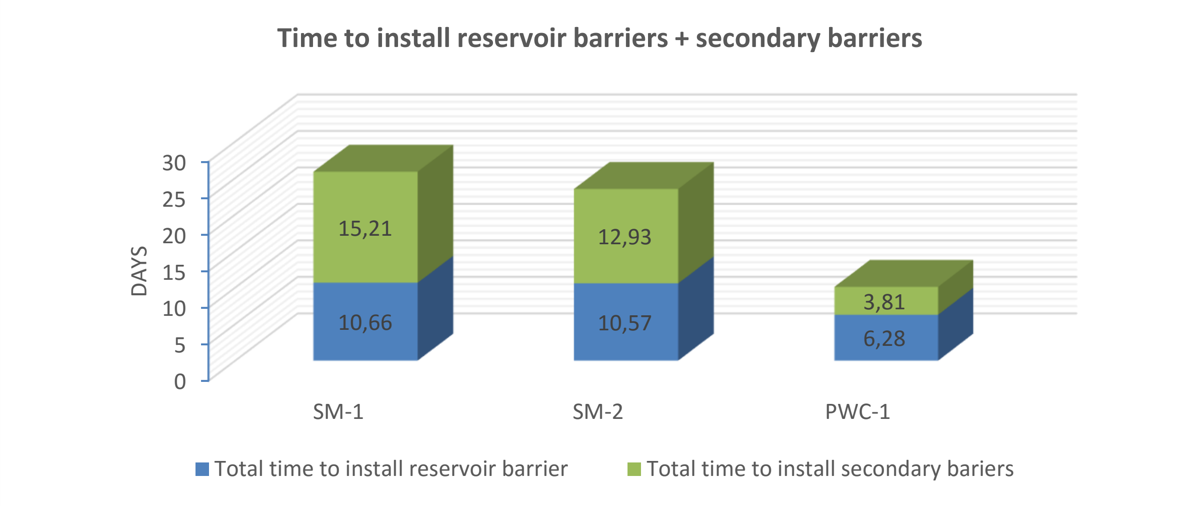


Figure 52 – Time to install reservoir barriers and secondary barriers

As stated above was additional time spent on well PCW-1 as the reservoir plug was drilled out in order to log the annular cement for verification. Table 14, shows that additional 3,33 days was used for this extra operational sequence. In other words, 3,33 days could potentially be eliminated, and installation of the reservoir barrier in well PWC-1 would only take 2,95 days. Figure 53, shows the potential-time consumption.

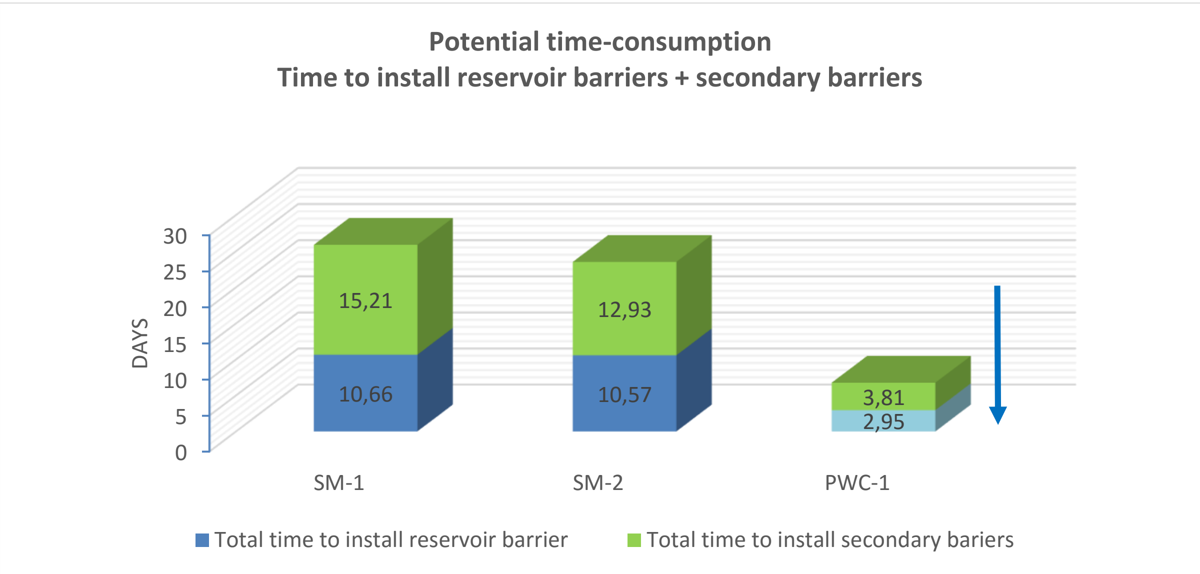


Figure 53 – Potential time-consumption. Time to install reservoir barriers and secondary barriers

Advantages and limitations of the section milling and PWC technology will be discussed in chapter 14.

13.5 Implementing new techniques to save time

From the case study above, it was found that the cutting and pulling the tubing, and setting of the reservoir and secondary barriers was the most time consuming operations.

Suggestions on technology solutions that can improve these operations are presented in the following.

13.5.1 Minimize Retrieval of Tubing

P&A operations are normally conducted by cutting and removing the production tubing. One possible way to save significant rig time during P&A operations is to leave most of the production tubing in the well or to retrieve it in a more effective way. Some production tubing's can be contaminated with NORM (Naturally occurring radioactive material) scale. These should be capped, labelled and stored, and disposal of these will bring high environmental costs which can be avoided leaving them in the well.

13.5.1.2 Tubing left completely in the well (44)

An economical way to reduce cost during P&A is to leave as much of the tubing as possible in the well. DrillWell research center have done a full-scale experimental test which demonstrate that it is possible to obtain good cement placement when the tubing is left in hole, with or without control lines.

In the test, several assemblies of 7" tubing's cement in 9 5/8" casings were used. Full-scale tests were performed to determine the sealing ability of annuls cement when tubing was left in hole.

Conventional cement was used on two assemblies, where one of them had a two lead control cable clamped on to the tubing. These assembles consisted of three casing lengths, and were 36 m long in total. Expandable cement was used on three other assemblies where each assembly consisted of one casing section, i.e. 12 m long. This time cable clamps were not used, but control lines were strapped to the high side of the tubing. Two of the assemblies had broad, flat control cables stretched along the top side of the annulus, while the last assembly had no cable. In both tests the assemblies were inclined to 85˚ off vertical, and the tubing rested on the casing wall resulting in a downward eccentricity of 7,8 %.

The cementing process for both cements were the same. The cement was mixed and pumped down the tubing, following a wiper ball, out into the annulus through perforations at the lower end of the tubing, and up the annulus. It should be noted that the pumping proceeded relatively slow, at ca. 300 L/min, in order to have gravity help with the displacement of brine. (In field application the cement slurry could be vulnerable to effects like U-tubing.)

The conventional cement was left to cure for one week, while the expandable cement was left for three weeks, allowing it to expand. All assemblies were isolated by RockWool, but the assemblies with expandable cement were heated externally and kept at a temperature of 90 ˚C, whereas the assemblies with conventional cement were not heated. It should be noted that the assemblies with conventional cement then experienced a large internal temperature difference which could affect the cement-casing interface when curing.

After curing, different pressure/flow tests were performed on the assemblies. The test set-up was a bit different for the two cements, but the assemblies were provided with pressure sensors placed along the casing annulus and on the tubing stub. During the pressure tests, fluid flow through the assemblies was measured at different pressures. From the measurements, an “effective” micro-annuli were calculated. It is used to translate pressure drops and leakage rate measurements into a course geometric measure for the space available for leakage between cement and the steel wall.

The result from the conventional cement showed that permanent micro-annuli was observed, also without any internal pressure in the assemblies. It is important to note that if the cement had cured for a longer time, it could have shrunk even more, and larger microannulus could have been observed.

It is also important to separate the permanent micro-annuli from the micro-annuli that are induced during pressure testing. For the expanding cement, which was pressing against the steel walls, a significant internal pressure was needed to create a microannulus with sufficient flow. Both types of micro-annuli were needed during the calculation of the microannuli thickness in order to explain the measured leakage rates. The calculated microannuli were however relatively small, and propably non-uniform. Even though there were leakage through the assemblies, the measured flowrates were relatively low and should not open for significant leakage rates in real P&A operations where the axial length of the cemented annulus is several hundred meters.

After finishing the tests, the assemblies were cut crosswise through at different places for visual inspection of cement placement quality. From the cut tests it seemed like the cement was perfect displaced in the annulus even with the lack of tubing centralization in the casing (fig. 54). The cement was also well placed around the control lines, and their presence did not represent any additional leakage paths.

This experiment show that it is possible to obtain good cement placement outside the tubing, when the tubing is left in hole. This experiment has however an idealized set-up and it is possible that it would be other results in a real well situation.

Figure 54 – Assemblies with expandable cement cut crosswise through. Assembly without control lines to the left and with control lines to the right. Perfect displacement around the control lines. (44)

13.5.1.3 Tubing partly retrieved (Tubing as a work string to place cement) (3)

P&A operations are normally conducted by cutting and removing the production tubing from the well. Statoil have however come up with a solution to minimize retrieval of the tubing by partly retrieve it and use it as a work string to place cement.

1. First is the well seal off by setting a mechanical plug in the well.
2. The tubing is cut and released just above the production packers.
3. Tubing is then elevated to gain access to the 9 5/8" casing to log the casing cement with CBL and USIT logging tools. The tubing is elevated to the required length to log the casing cement and held in place while performing the logging operation.
4. If interpretation of the logs shows good qualify cement which bonds to formation and casing, a cement plug can be placed on the mechanical plug. Cement is pumped through tubing. After the cement has set the tubing is landed on top of the cement plug and left in the well.

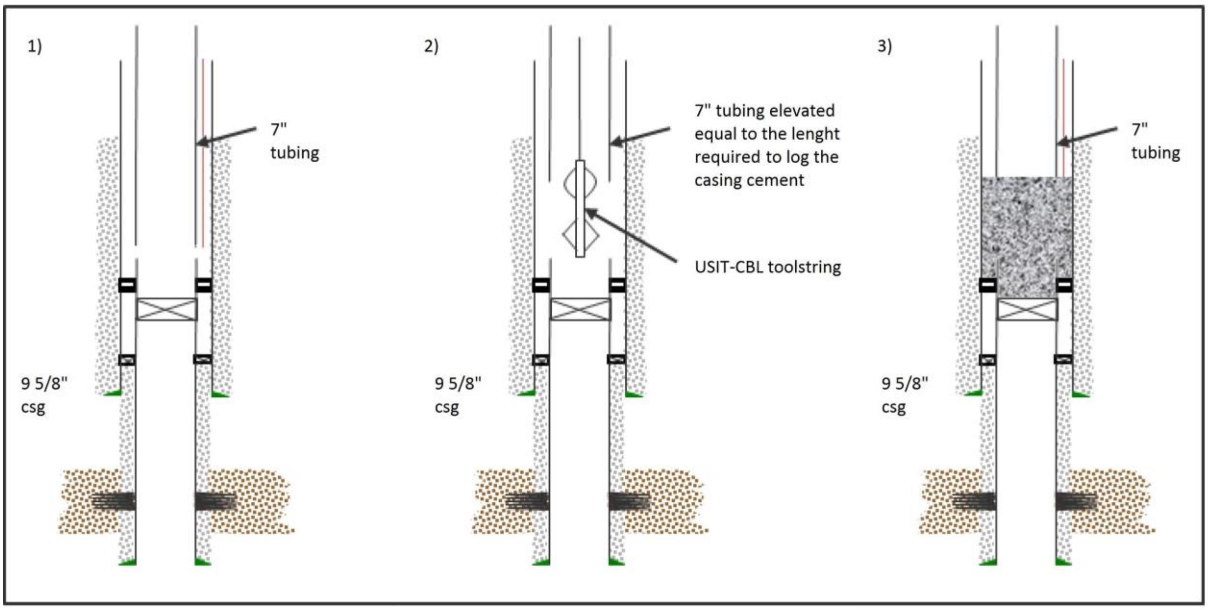


Figure 55 – Tubing as a workstring to place cement (3)

Statoil have used this method on the Heimdal field in the North Sea on a permanently plug and abandonment campaign. Figure 56 displays the percentage saving of the total P&A operational time per well on the Heimdal field. The average time saving on the wells were 12,8 %. This method also reduces the handling of the tubing at deck top side and the subsequent disposal and logistic problems.

The same method has also been used on Statfjord Øst (two subsea wells).

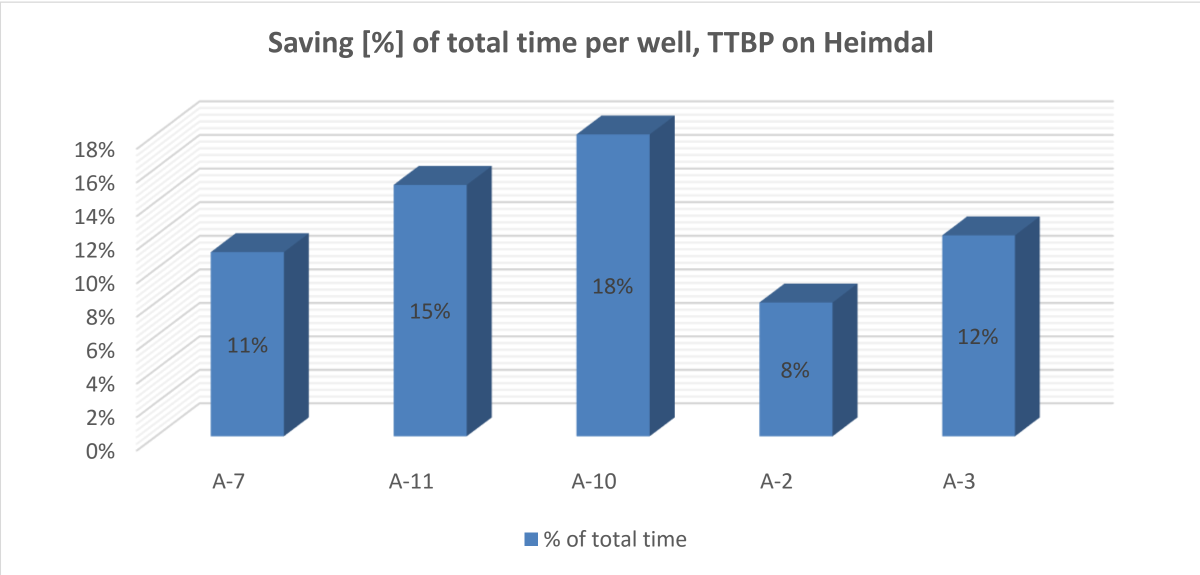


Figure 56 – Percentage saving of total time per well, TTBP on Heimdal (3)

13.5.1.2 Wireline cut and pull (45) (46)

Before the P&A operation start, the well needs to be prepared. The preparation work takes place before the rig is placed on location and is known as "offline" work. If just a few more operations can be performed offline without the rig, the potential of reducing cost is high. The preparation work is normally performed using a wireline system.

Pulling the tubing out of hole is normally done right after the rig is placed on location. To be able to do this work safely the x-mas tree needs to be nippled-down and replaced by nippling-up BOP and riser. On old platform wells the original drilling equipment in place might have been removed. For such cases, drilling rigs such as jack-up rigs with heavy duty lifting equipment is used to retrieve the tubular out of the well. Similarly, for subsea wells, where floating drilling rigs such as semi-submersibles are needed to pull the tubing out of the well.

In the North Sea, wells may be deep and completed with large dimensioned tubulars, making the cumulative weight high. Therefore, is it a challenge to do this work with wireline as the cables does not have sufficient strength to pull the entire tubing.

Aker Solutions are working on a solution for retrieving tubulars for a well that requires less pulling force than the current system and methods. The objective of their invention is to provide a system and method that is more time and cost efficient. The solution is based upon the principles of using lighter well servicing techniques as wireline for retrieval of the tubing.

Before the operation start, a riser and BOP needs to be installed. The first step in the process is to remove the tubing hanger. A tubing hanger cutting tool run is on wireline in the well to cut the tubing right below the tubing hanger, typically close to a clamp, to ensure that the control line is cut as well. Then the cutting tool is retrieved and a pulling tool is employed to retrieve the tubing hanger. The shear ram valve in the BOP will act as a barrier when the tubing hanger is pulled out of the well. A wireline rig-up mast are typically mounted adjacent to a wireline lubricator prior to commencing the tubing retrieval operation.

The next step in the process is to run a tubing cutter tool into the well and cut the tubing into a planned segment. The length may vary, depending on well conditions and operational constrains. A deep set barrier plug compromising a check valve, is installed in a lower portion of the tubing segment. Then a tubing retrieval tool is engaged at the top portion of the tubing.

The retrieval apparatus comprises a guide nose, an anchoring module, a control module, a termination module and a sealing module which seals of the relevant tubing interval.

The next step is a key step in the invention. The top portion of the tubing segment is filled with a low density fluid in the form of a gas, e.g. nitrogen, or a liquid having lower density than the liquid being replaced. The lower density fluid will displace the heavy fluid out of the tubing via the check valve of the deep set barrier. This will generate a buoyancy effect that acts on the tubing segment, which is the whole essence of the method. To exemplify, a 100 m tubing weighing 2530 kg in air, will at 1500 m TVD (filled with nitrogen), provide a hook load on 350 kg in a well filled with 1.7 s.g. brine. This is a significant reduction and make it possible to utilize wireline for tubing retrieval.

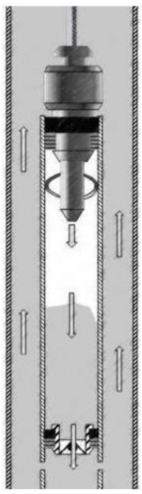


Figure 57 – Wireline cut and pull. Low density fluid is injected to displace the heavy fluid

The process in then repeated with a new cuts and segment pulled out of hole until the entire tubing has been retrieved from the well.

This method shows that wireline can be used to retrieve tubing from a well, however this system is in the development phase, and there are some concerns. The system needs additional equipment compared to conventional systems and methods. How the low density fluid is going to be injected into the tubing is an issue. A future goal could be to have one or more lines inside the wireline. Another concern is how the buoyancy can be regulated or balanced. Sensors could be employed inside and outside the tubing segment to monitor pressures, motions etc. to balance the buoyancy. Surface equipment that can bleed of gas is needed. In some wells the tubing may be stuck due to settled material such as barite. In such a case, coiled tubing can be utilized to circulate fluid through the annulus so that the settled material can be softened or eroded away. In addition, a pipe handling system is needed when the tubing segments come to surface.

The idea behind this invention is interesting and If this technology can be commercialized and proven to work, it can reduce rig time. The method could be done offline and eliminate the need to switch to a rig after the preparation work has finished. Retrieval of tubing could then be included in the preparation work, and potentially reduce the cost.

13.5.2 Improve section milling (29)

Section milling is a technology that should only be used when absolutely necessary, due to all the challenges that comes with it. There are however lack of technology that can replace it in every way, so it has no persist for now. Conventional section milling techniques usually involve multiple trips in and out of the well to mill the casing and under-ream the open hole section. Section milling and under-reaming have traditionally been performed in separate runs. This is both time consuming and expensive, and therefore undesirable. A key factor in reducing the number of trips in the well is to develop robust multipurpose tools which can do several tasks in one run.

In the case study it was revealed that section milling and under-reaming represented as much as 53,83 % of the total time consumption for the P&A operation on well SM-2. For well SM-1 it represented 37,27 % of the total time consumption, a bit less, but still a remarkable amount of time.

13.5.2.1 Section milling and under-reaming in a single trip solution

The standard practice of conventional section milling operation has been to perform two separate runs when milling and under-reaming the open hole formation. Researchers from Schlumberger has developed a hybrid section milling and under-reaming single-trip BHA tool with a 3D time-based drilling dynamic simulation system. This is a step change in conventional industry practice as it can do two dedicated jobs in one run.

The singe-trip BHA is a combination of a newly designed under-reamer and a section mill combined on the same BHA. The BHA incorporates a ball drop circulating and well conditioning valve which ensures controlled activation and deactivation of the section mill and underreamer at the correct time of the operation.

While tripping in hole, the ball-activated valve is open to the annuls to allow the string to self-fill. This eliminates the extra time that is required when top filling the pipe. When the BHA reaches milling depth, milling fluid is pumped through a pressure shear sub installed at the top of the string through the open ball-activated valve. This allow shearing and conditioning of the fluid to ensure that the rheology is suitable for hole cleaning. Once the fluid rheology is confirmed a ball is dropped to shut-in the valve and section milling can commence. After milling the required casing window length, the BHA is pulled up and the under-reamer is positioned at the top of the window. A ball is dropped to activate the under-reamer and then the wellbore is underreamed beyond its original dilled hole size, ensuring that any old cuttings, contaminants or traces of cement are removed.

The 3D time-based drilling dynamic simulation system is able to accurately emulate actual BHA drilling behavior. It can factor in well trajectory, drilling parameters, mud weight, drill-string contact, and cutting structure interaction with formation/casing.

Before the operation starts, the dynamic simulation system carries out analysis to simulate and optimize the underreaming process based on the practical BHA and well plan. The analysis is a sensitivity analysis which identifies the optimal operational parameters which will deliver high ROP and low vibration/stick-slip ratio to avoid any service quality incidents. Then, the parameters are used to examine the underreamer off-center distance to ensure sufficient new virgin rock exposure in all directions.

A pre-run dynamic simulation analysis together with objectives, risk and operating guidelines is also used to aid the pre-job planning and to create a P&A roadmap to ensure a successful operation.

The single-trip BHA have been used on a well in field testing. Following the roadmap, three 9 5/8" casings were successfully section milled and the open hole was subsequently underreamed. The operation was stable and had a high level of consistency. After the operation, the system tools were disassembled and inspected. Low wear and good postrun condition confirmed stable performance during operation. Caliper-measurements showed that the desired hole quality were achieved.

Conventional two-trip system: Section mill BHA, reamer BHA

New single-trip system: Hybrid section mill and reamer BHA

Figure 58 – Conventional two trip system versus new single-trip system (29)

Analyses of the rig time spent on the well showed that the single-trip system saved more 49 hours of rig time compared to the conventional two-trip system. The two-trip system typically required 100 hours for the three sections, while the singe-trip used roughly 50 hours. This means that the singe-trips system had a clear 50 % reduction in time consumption and saved significant rig costs. The system also boost efficiency due to the 3D time-based drilling dynamic simulation system, and minimized HSE risk as a result of reduced BHA handling on the rig floor.

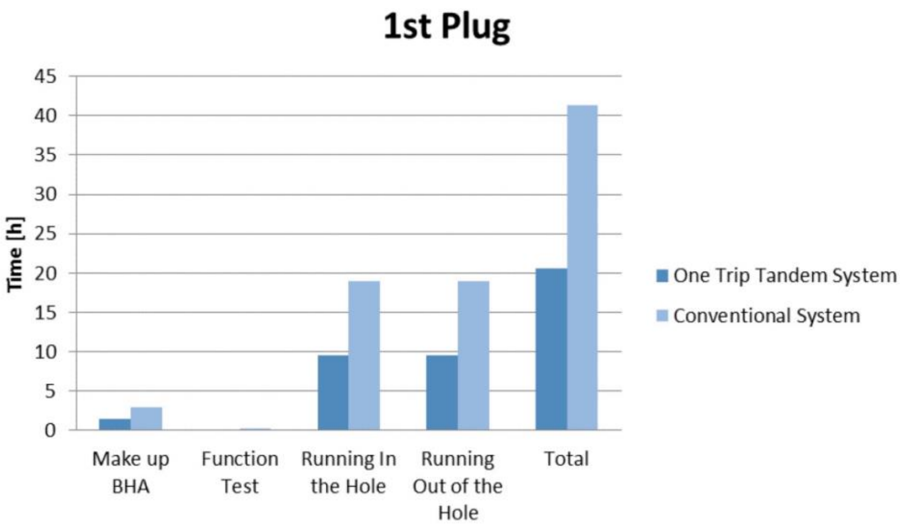


Figure 59 – Rig time comparison between single-trip system and conventional two-trip system – Plug 1 (29)

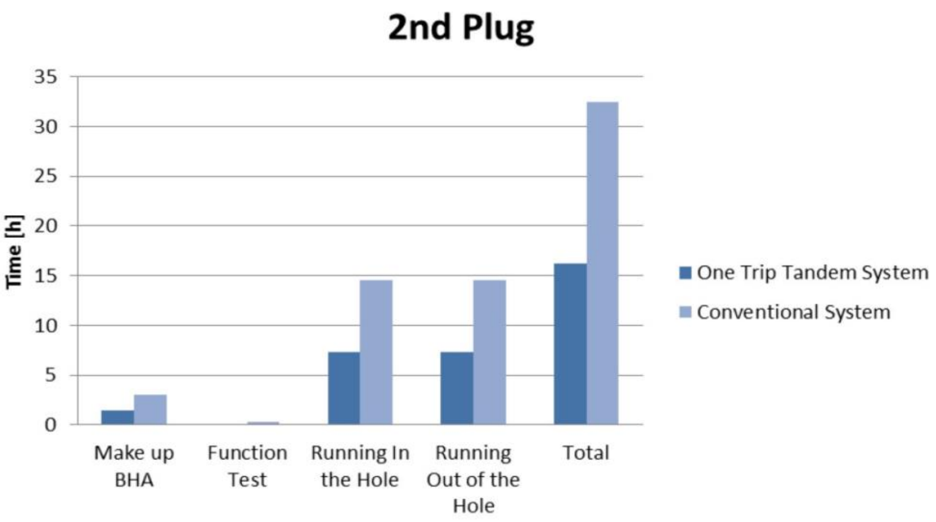


Figure 60 – Rig time comparison between single-trip system and conventional two-trip system – Plug 2 (29)

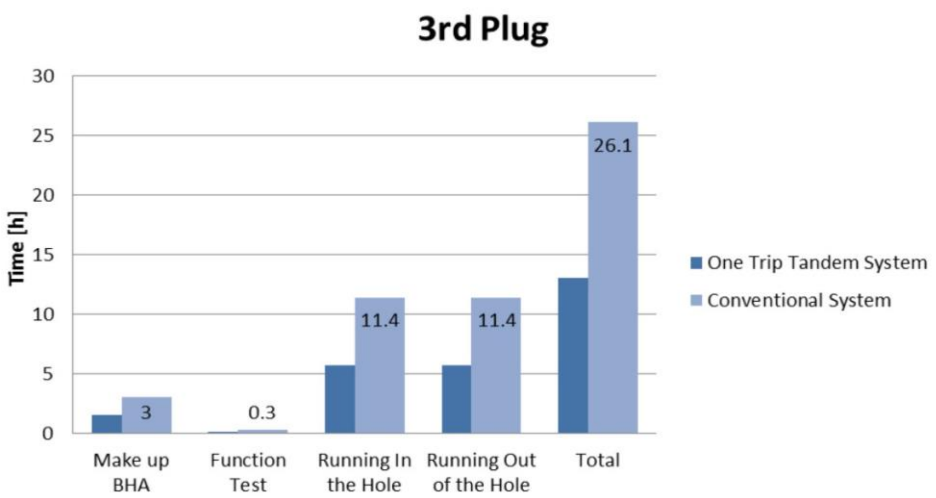


Figure 61 – Rig time comparison between single-trip system and conventional two-trip system – Plug 3 (29)

14 Discussion

The major challenge with P&A is to make the operation economically sustainable for operating companies and national authorities. It is important to minimize costs as the P&A operation involve high investments with no financial returns. One way of reducing the cost is to perform the operation with new tools and techniques to increase the efficiency and effectiveness without compromising safety and job quality.

14.1 Section milling vs PWC

14.1.1 Experience from Case Study

P&A operations performed with conventional technology is time-consuming and costly. To address the situation of long average operational times, this thesis included a case study which involved an investigation into the time-consumption of the various sequences of P&A operations.

The case study presented in chapter 13 compared conventional section milling with the PWC technology from HydraWell. Data from three individual P&A operations were presented. All three operations involved plugging of three individual wells at the same field. The operations were performed in similar environments and are considered comparable. Two of the wells were plugged and abandoned with conventional section milling technology - well SM-1 and SM-2. While one well were plugged and abandoned with the PWC technology from HydraWell - well PWC-1.

The total P&A operation took 37,93 days on SM-1, 31,43 days on SM-2, and 18,12 days on PWC-1. These numbers reveals that the PWC technology completed the operation 19,81 days faster than for well SM-1 and 13,31 days faster for SM-2.

Many of the challenges associated with section milling were encountered during the plugging operations on well SM-1 and SM-2. Pack-off tendencies due to insufficient swarf transport were encountered during all section milling operations. It led du several delays during the operations, but this is commonly seen during section milling operations.

A detailed breakdown of the operations revealed that the installation of the reservoir and secondary barrier was the most time-consuming operations. Off the total time-consumption on well SM-1, these two stood for 28 % and 40 % respectively – a total of 68 %. On well SM-2, they stood for 35 % and 43 % respectively – a total of 78 %.

The time-consumption of the installation of the reservoir and secondary barriers on well PWC-1 were significantly shorter. Installation of the reservoir and secondary barriers for well PWC-1 were 15,77 days and 13,41 days less than for well SM-1 and SM-2, respectively.

Nevertheless, by eliminating the additional time that were used on drilling out the reservoir plug, logging the annular cement and re-cementing, an additional 3,33 days could potentially have been saved. Installation of the reservoir barrier in well PWC-1 would then only take 2,95 days, as shown in figure 62. Installation of the reservoir and secondary barriers for well PWC-1 could potentially be 19,10 days and 16,74 days less than for well SM-1 and SM-2, respectively. This implies that the PCW technology reduces the time to install the reservoir and secondary barrier with almost 74 % compared to well SM-1 and 71 % compared to well SM-2.

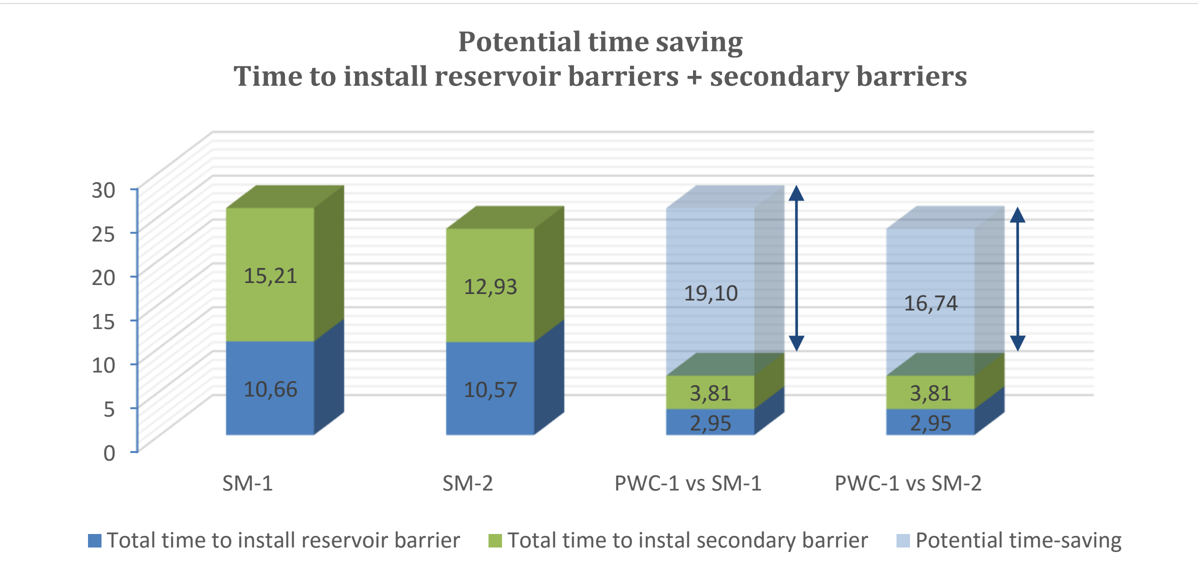


Figure 62 – Potential time saving – Time to install reservoir barriers and secondary barriers

14.1.2 Advantages for PWC vs section milling

The PWC method introduces several advantages over the conventional section milling operation. Many of these advantages contribute to streamline the P&A operation and make it more efficient. Some of the advantages are presented in the following.

14.1.2.1 Casing remains intact

Section milling grinds away a section of the casing to get access to the formation, while the PWC method obtains access through perforations in the casing. In this way the casing is left intact. This makes re-entry of the well possible if any problems should occur. Re-entering the well after the casing is removed is more or less impossible as the cement plug is expected to be harder than the formation. Drilling out the plug would most likely fail as the drillbit would slip off and make a sidetrack into the formation or at best just skim along the plugs surface. This also makes it difficult to assess the competency of a plug set by section milling if any operational problems were encountered during the operation. For plugs set inside perforated casings, the casing walls will guide the drillbit downwards, thus making it possible to re-enter the well by drilling out the cement plug. This also makes it possible to verify the annular cement before abandonment.

14.1.2.2 Eliminates generation of swarf

Many of the operational challenges related to the section milling operation is caused by the generated swaf. Milling a typical 50-meter section of a 9 5/8” casing can generate around four tons of swarf. Moreover, some operators only recovery approximately 25 % of the generated swarf. This means a lot of swarf is left downhole and can interfere and decrease the sealing capabilities of the cement plug. As the PWC method eliminates the generation of swarf many challenges are solved. By using the PWC method there is no risk of swarf getting stuck in the BOP, and so integrity is maintained during the operation. It also eliminates the need of handling equipment and all the logistical problems it entails.

14.1.2.3 Well control

There might by pressure build-up in the annulus which is released once the casing is perforated or milled through. An advantages of the PWC method is that the BOP is intact during the whole operation. If gas enters the well through the perforations it will just be circulated out. The BOP offers well integrity during the operation, and is ready if any incident should arise which could result in loss of well control. During a section milling operation, swarf can get stuck in the cavities of the BOP. If a kick should occur during the milling operation, swarf debris could block the BOP rams, which would be critical concerning well integrity.

The PWC system is also engineered for optimum well control during all phases of the operation. It is designed with an in-cooperated flow-by-pass system which allows fluid to circulate through the tool while tripping in and out of the well. This eliminates surge and swab effects and allows for higher tripping speeds, reducing non-productive time spent on running in and out of the hole.

This also allows for higher circulation rates while washing. Higher circulation rates will make the washing of the annular space more efficient, and transport debris efficiently to surface. The by-pass-system is also advantageous to circulate out potential gas that entered the well after perforation.

14.1.2.4 No viscous milling fluid

During section milling operations huge amount of swarf is generated. The swarf is removed from the well through circulation with special milling fluid or mud created especially for that specific purpose. The generated swarf is generally larger and denser than normal cuttings, and is also more irregular shaped. This means that the milling fluid need a sufficiently high viscosity to transport swarf to surface, while at the same time keeping the exposed open hole stable. The ECD of the fluid is normally designed to stay between the fracture gradient and pore pressure gradient of the formation. During section milling operations it may be required to have viscosity profiles which generates ECD which exceeds the fracture gradient of the exposed open hole. This could lead to fluid losses and many other well control problems.

With today's technology it is possible to mill faster than it is possible to circulate out the generated swarf. It is therefore important to obtain a "sweet spot" where ROP, flow rate, pump pressure and viscosity are working together. When all parameters are working together transportation of swarf can be optimised and the ECD can be kept below the fracture gradient.

For the PWC method there is no need for special milling fluids with high viscosity profiles as there is no generated swarf.

14.1.3 Limitations and key performance criteria for PWC vs section milling

14.1.3.1 Condition of the annular cement

Prior to the P&A operation it is important to obtain information about the condition of the annular cement. The presence and integrity of the annular cement is verified through logging operations as described in chapter 5. To assure that the well is sealed properly it is important that well barrier extend across the full cross section of the well and include all annuli. It is therefore important to validate the condition of the annular barrier.

If evaluation of the annular cement reveals that the cement is insufficient and cannot be approved as a competent barrier, the options are section milling or the PWC method. If the annulus is filled with significantly amount of cement of insufficient quality, it can be difficult to wash efficiently with the PCW tool. In such a case section milling might provide the best solution. However, if old fractured cement is present in the annulus the PCW method can be used. For the PWC method to be used, it is essential to know the condition and content of the annular barrier to ensure that it is possible to efficiently wash the annulus and to be able to design a wash fluid with suitable properties.

14.1.3.2 Contamination of cement

A properly washed and flushed annulus is essential to prepare the plugging interval to receive cement and to ensure long term quality of the cement placed in the annulus.

The second generation PWC tool utilizes the HydraHemera Jetting Tool to wash the annular space. Clean mud is directed through nozzles in the jetting tool, creating high energy jets of mud. After the jets have clean the annulus space between the casings and the formation, a spacer fluid is pumped through the jetting tool into the area.

The spacer is used to displace the washing mud from the annulus and to water-wet the casing and formation so that the cement can bond properly. The spacer must be carefully designed to prevent intermixing with mud present in the annulus or cement which is pumped behind the spacer. This can be achieved by designing the density and viscosity profile of the spacer to be higher than the density and viscosity profile of the mud and lower for the cement slurry.

However, as mud, spacer and cement is pumped through perforation in order to access the annular space, and returns are made through the same perforations, some degree of mixing should be expected. If the cement is contaminated by spacer intermixing it can affect the isolation properties of the cement. It can for example cause changes in thickening time and compressive strength of the cement. This is a limitation of the PWC method.

To ensure a successful plug placement it is therefore important to consider the performance and design of the fluids to ensure that they are compatible with each other while having the right properties.

14.1.3.3 Verification of plug set in double casing

A large challenge with the PCW method is verifying the plug when it is set over two annuli. Cement plugs set with section milling will bridge over the entire cross-section of the well, and eradicate all potential leak paths – including channels, micro-annuli, and mudcake. With the PCW method the cement is set in the annuli, which means it have to bond to the casing in addition to the formation.

Cement plugs set over one annulus with the PWC method can be verified by logging. This is however not possible when the cement plug is set over two annuli as todays logging technology has severe difficulties logging through multiple casings. Consequently, the plug set over two annuli have to be pressure tested similarly to plugs set with section milling technology.

ConocoPhillips performed a long term negative pressure in a well where a plug was set with the HydraHemera in 7” x 9 5/8” casing. The test lasted for 100 days with a pressure of 1000 psi to check if the plug sealed properly. Pressure monitoring at the wellhead showed an increase in pressure. This normally indicates that the plug is leaking, but conversations with ConocoPhillips revealed that there are uncertainties whether the plug is leaking or the casing is leaking (47). If the casing is leaking it is most likely due to faulty joints/couplings in the casing. But is can also be caused by mechanical or chemical damages along the casing.

An onshore verification test of the HydraHerma system was performed at Ullrigg, Stavanger. Ullrigg is a drilling rig with advanced test facilities owned by the International Research Institute of Stavanger (IRIS). In the test was a 7” casing cemented off centre inside a 9 5/8” casing with a mixture of 25 % cement and 75 % barite. This was placed in a 13 3/8” casing which represented the formation. The HydraHemera system was run, and the well model was washed with mud, the annuli flushed with spacer and the entire section was sprayed with cement (AbandaCem). AbandaCem is a cement technology provides by Halliburton. It is designed with additives to reduce hydration shrinkage, and to post-set expand. After the cement had set, the test assembly were cut into 7.5 cm pieces. Evaluation of the pieces showed a god result. Some small cavities of insignificant size where present in the annulus between the casings. In figure 63 are three of the pieces shown. Picture 1) shows a cross-section where perforations are present. In picture 2) is a small cavity present. And picture 3) shows a perfectly displaced cross-section.

Figure 63 – Three example cross sections (34)

The onshore test demonstrates that the HydraHemera system is working when set across two annuli. Several long term negative pressure test should be performed in offshore wells to approve that plug is sealing and that the technology is working. If several successful tests are performed, it may be necessary to only perform a short term negative pressure test or a positive pressure tests.

14.2 Conventional section milling vs upward section milling

To challenge the conventional section milling, another concept is under development. The new concept involves performing section milling upwards, rather than downwards as with conventional section milling. This is achieved by using tension to drag the assembly up, rather than using weight to push in down. The primary goal of this method is to leave the swarf downhole. The advantage of leaving the swarf downhole is that there is no need for high viscosity milling fluids, and HSE and well control issues are eliminated.

The limitation with conventional section milling technology is that it is possible to mill faster than it is possible to circulate out the generated swarf. Hole cleaning is a limiting factor for the progress of the operation. As transportation of swarf is eliminated from the upward milling operation it is possible to mill faster, and thus reducing the time-consumption of the operation. An upward section milling tool from West Group was presented in section 12.1.2. West Group reports that the SwarfPak will have a milling speed in the range of 60-100 ft/hr. Current milling technology has milling speeds normally in the range less than 10 ft/hr. The SwarfPak would potentially offer an enormous improvement over the conventional milling speed.

Although upward section milling is an interesting concept, it has its challenges. The technology is not yet proven, and there are concerns about the technology. Conversations with the industry reveals that they are not convinced of what they have seen until now. There are concerns about the possibility to keep a constant upward force when milling under tension. An unbalanced force could possible make irregular depths of cut and damage the mill. The BHA is also designed with geometry requirements that could potentially reduce the perceived effectiveness. The overall benefits are believed to be very limited.

Leaving the generated swarf downhole has many benefits, but it also poses a big concern. One of the reasons swarf is removed from the well is because it may interfere with the barrier elements. If large amount of swarf is present at the plugging interval, the sealing capabilities of the plug can be affected.

For the technology to work it has to be more refined and further tested.

14.3 Conventional section milling vs Plasma-based milling

Since 2013 has a company named GA Drilling led a joint industry project (JIP) to develop a plasma-based milling tool. Instead of conventional rotary milling the tool uses a non-contact approach which generates heatflow to melt and disintegrate the casing, casing-cement and formation.

A significant advantage with the plasma-based milling tool is that the generated swarf or disintegrated material is very small compared to the massive swarf produced by conventional section milling. Analysis of the generated swarf from the plasma-based milling tool shows that most of the swarf is in the range of 1-5 mm. This reduces the possibility of well control incidents and ensures that the BOP has integrity during the operation. It also reduces the need for high viscous fluid and eliminates the chance of mechanical stuck pipe. The milled material is also easier to handle when it arrives at surface.

The non-contact approach also minimizes wear and tear on the tool itself and limits the cost of damaged equipment and stuck tools. Stuck tools is commonly seen in conventional section milling operations and cause significant time delays. The plasmabit is a more reliable tool, and can operate continuously and almost uninterrupted.

The plasma-based milling tool is expected to have a ROP around 30 ft/hr. Compared to conventional section milling which reach ROP about 10 ft/hr, a significant time-saving is expected. As the operation also requires less tripping, additional time will be saved.

The system is also designed to be used with coiled tubing, which means it can be deployed from a light well intervention vessel (LWIV). This reduces the need for larger and heavier equipment, and saves space and logistical problems. It also offers a cost-efficient solution compared to rigs.

Another advantage is that the plasma-based tool can operate through tubing, thus eliminating the need of XMT removal. Tubing removal before the operation is also eliminated as the tool is designed to mill tubing and casing in one run. This means the conventional P&A operation can be simplified, resulting in a faster operation.

Although it is still at the pre-commercialisation stage, all these advantages make the plasma-based milling technology promising. Testing a full-scale prototype in its intended environment is expected during 2017. The result of this testing will reveal if the technology work as anticipated and if it is as efficient as presumed.

14.4 Regulatory framework & fit for purpose abandonment

In the 1990s, the oil industry in Norway experienced a rising cost of offshore developments, while the price of oil was falling. The NORSOK standards was developed to reduce cost, add value and eliminate unnecessary activates and operations on the NCS.

The NORSOK D-010 is the standard dealing with well integrity in drilling and well operations, and has a specific chapter about plug and abandonment. The NORSOK D-010 has been updated and revised significantly since it was first developed, and revision number four is currently in use. In 2004 was revision three of D-010 published, and at the same time was a sudden increase in the average time-duration of permanent P&A activities seen. The average duration suddenly increased from 16 days to 35 days. Even though it is not documented, it is believed that the release of rev. 3 had a major impact on the sudden increase.

The oil industry is currently experiencing more or less the same as in the 1990s. The industry is suffering due to a drop in oil price and is forced to become more cost-efficient. As the industry is again facing challenges it is important to come up with new initiatives to make the business sustainable in the future.

First and foremost, it is important that regulations and standards are frequently revised and are kept up to date as the industry continuously changes the game and new technology is developed.

The current regulations use prescriptive requirements, which means it describe one solution or result that the product, process or service is to produce. This means for example that the required number and the length of permanent well barriers are the same for all types of wells. The requirements do not differentiate between a reservoir with limited or significant flow potential. The requirements are the same for HPHT reservoir with significant flow potential as for a depleted reservoir with limited flow potential. There is a large variety of well types, and all wells are different, so there is no point having the same P&A requirements for all wells.

A solution could be to introduce framework with a risk perspective. Instead of one solution-fits-all, a fit for purpose methodology can be used. Fit for purpose P&A can optimize the well abandonment design for each specific well. A tailor-made solution for each specific well can provide a cost-efficient solution for less critical wells while at the same provide a safer solution for higher risk wells.

14.5 Include P&A in the initial well design

P&A has in the past been conducted as an afterthought in the oil industry. In the newest revision of NORSOK-D011, rev. 4, there is a short sentence mentioning that the well shall be designed for operations encompassing all phases of a wells lifecycle, including plug and abandonment.

Wells completed decades ago were not designed with abandonment in mind and this makes the P&A operation more challenging today. Another challenge is that documentation of old well can be inadequate or partly missing. Information about the primary cement job can be inaccurate, and poor primary cement jobs can even have been accepted as there was no thoughts regarding future abandonment. This is a major challenge today, as reestablishing the external well barrier (e.g. casing cement) is complex and time-consuming. This has traditionally been solved by operations as section milling, or currently with new technologies as the PWC method.

The operators should move away from idea that it is some else's problem later on. This problem can be eliminated by involving P&A early in the well planning phase and make it an integral part of the original well design. It should be put more effort to the primary cement job. A successful primary cement job is very beneficial as the cement between the formation and the casing is a key factor to achieve an effective and simple P&A operation. Proper documentation of a verified successful cement job will save additional time as it might not be necessary to log and evaluate the external/annular barrier prior to the P&A operation. If any conditions should affect the long term isolation performance of the annular cement, it will be necessary to evaluate the annular barrier. It might be possible to add sensing materials to the cement in the future, to make the interpretation of logs easier and more reliable. It is especially important to know that the cement sheath has sufficiently long sections with homogeneity and that there is good bonding between the cement-formation and cement-casing.

When designing the well, it might be possible to design it such that sections of the well is prepared for a barrier element (e.g. cement plug). It might for example be possible to leave a section of the well without control lines, or that the control lines can easily be removed. This can lead to a higher cost for the initial construction of the well, but it should be negligible compared to the cost of plugging wells as it is done today.

If operators have a clear idea on how the well is to be plugged already in the planning phase, a lot of time and money can be saved.

14.6 The process of setting a well barrier – short summary

The process of setting a well barrier starts with an evaluation of the external barrier to investigate if the annulus is sealed off (e.g. with cement or creeping shale). If the evaluation shows that there is no external barrier in the annulus the casing has to be removed or opened up to get access to the annulus. Once the casing is opened up, the area has to be cleaned and prepared to receive cement. To achieve zonal isolation, it is vital that is process is done properly. The next step in the process is setting the plug. After the plug is set is has to be verified to check that it has the required properties to seal the well for eternity.

To make the P&A operation more efficient, these four steps have to be performed as streamlined and fast as possible, while fulfilling the requirements and not compromising quality and safety.

The PCW method investigated in this thesis is the technology per now performing this operation most efficient while fulfilling all the NORSOK D-010 requirements.

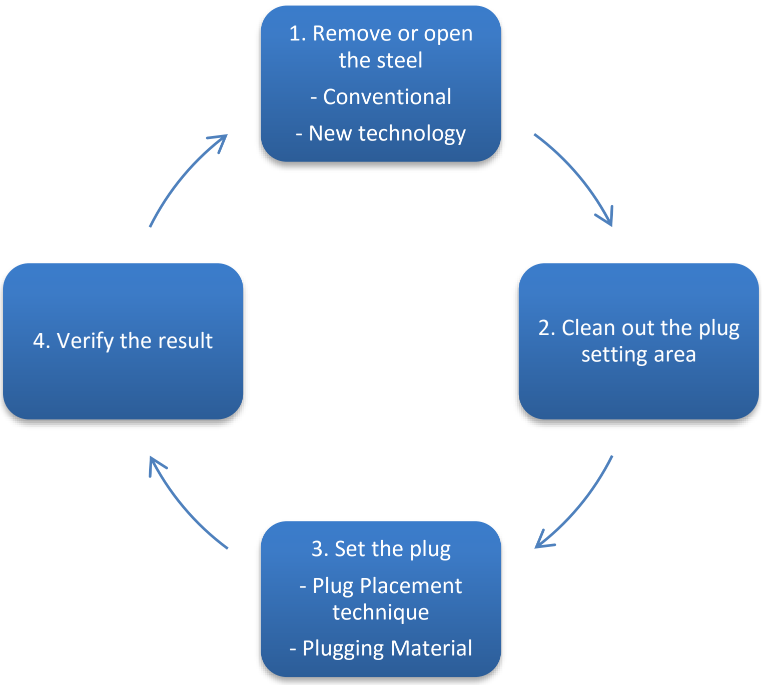


Figure 64 – Process of setting a well barrier element

15 Conclusion

The primary objective of this thesis work has been to investigate the conventional section milling technology along with its limitations and challenges, and compare it with new technology's with respect to time and scope.

The success of a permanent abandonment plug is measured by its ability to effectively bridge across the entire wellbore and seal in all directions. In cases when the casing does not have an external barrier in place, the traditional solution has been to section mill the casing, underream the open hole, and set a balanced cement plug. This is a time-consuming and costly operation, and comes with several challenges. Most of the challenges with the section milling operation can be led back to the generated swarf. The case study revealed that the installation of the reservoir and secondary barrier was the most time-consuming part of the operation, representing an average of 73 % of the average P&A operation of 34,68 days.

To address the challenges with the conventional technology, new methods and technologies have been developed, one of them being the PWC technology from HydraWell. The PWC technology can be used as an alternative when the external barrier is insufficient and free pipe is present. It eliminates many of the challenges associated with section milling operations, and introduces an efficient solution to place a rock-to-rock well barrier. By perforating the casing rather than mill it, all the problems with the generated swarf is eliminated. The case study revealed that the use of the PCW technology could potentially save 72,5 % of the time used to install the reservoir and secondary barrier compared to the section milling operation. The total P&A operation with the PWC technology could potentially take 14,79 days – 58 % less than the P&A operation utilizing the section milling technology.

Even more time could potentially be saved if the PWC technology is used on multiple casing strings. There is however still a challenge to verify a plug set over two annuli as it is not possible to log through multiple tubulars. The large test on Ullrig was successful, but more testing is necessary to verify that the plug is sealing when set over two annuli.

Among the concepts the plasma based milling technology from GA Drilling is found to be the most promising. It is believed that this technology has potential to save 30-50 % of the overall time-consumption compared to conventional section milling. The Plasma-based milling tool can also be used regardless of the condition of the annular cement. The tool also generates very small particles of swarf, eliminating many of the challenges associated with the conventional section milling operation.

The petroleum industry is conservative and prefer well-proven technology unless it can solve a very current or specific problem. The vast majority of P&A operations are currently being done with conventional technologies. In order to reduce cost, operators need to adapt new technologies, and work together with service companies to develop cost-efficient solutions.

16 Recommendations for further work

- Further testing on new materials – long term integrity.
  - Although the cement technology has been improved.
- There is today a large difference around the world regarding the requirements of the minimum length for a cement plug and the cement height in annulus. There seems to be no common understanding in the industry what the exact required length/height is to be sufficient. More scientific research should be done on this topic.
- Improve barrier verification, logging tools and interpretation methods.
  - Logging through multiple casings.
  - Study the possibility of implementing "sensor-additives" to the cement to obtain better logging results.
- Study if it is possible to activate or induce shale to act as an external well barrier.
  - Temperature/pressure/additives.
- Plugging solution where tubing can be left in the well.
- Solution for retrieval of control cables and lines while leaving the tubing in the well.

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Appendices

All tables in this appendices are from NORSOK D-010 rev. 4.

Table 24 – Cement plug (1/2)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. A program shall be issued for each cement plug installation.
2. For critical cement jobs, HPHT conditions and complex slurry designs the cement program should be verified by independent (internal or external) qualified personnel.
3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.
4. Cement slurries used in plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (CO_2, H_2S).
5. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
6. It shall be designed for the highest differential pressure and highest downhole temperature expected including installation and test loads.
7. A minimum cement batch volume shall be defined to ensure that a homogenous slurry can be made, taking into account all sources of contamination from mixing to placement.
8. The minimum cement plug length shall be:
<table>
<tr><td>Open hole cement plugs</td><td>Cased hole cement plugs</td><td>Open hole to surface plug (installed in surface casing)</td></tr>
<tr><td>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.</td><td>50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
9. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
10. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
a. The cement plug shall extend 50m into the casing.
b. It shall be set on a foundation (TD or a cement plug(s) from TD). The cement plug(s) shall be placed directly on top of one another.
11. A casing/liner shall have a shoe track plug with a 25 m MD length.</td><td>API Spec 10A Class ‘G’</td></tr>
</table>

Table 24 – Cement plug (2/2)

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial verification</td><td>
1. Cased hole plugs should be tested either in the direction of flow or from above.
2. For the shoe track to be used as a WBE, the following applies:
a. the bleed back volume from placement of casing cement shall not significantly exceed the calculated volume; and
b. it shall be either pressure tested and supported by overbalanced fluid (see EAC 1) or inflow tested.
3. The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
4. The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
5. The plug shall be verified by:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging.</td></tr>
<tr><td>Cased hole</td><td>Tagging.
Pressure test, which shall:
a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs; and
b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.</td></tr>
</table>
</td><td></td></tr>
<tr><td>E. Use</td><td>None.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>If one continuous cement plug (same cement operation) is defined as part of the primary and secondary well barriers, it shall be verified by drilling out the plug until hard cement is confirmed.
1. An open hole cement plug extended into the casing shall be pressure tested.</td><td></td></tr>
</table>

Table 52 – Creeping formation

Features	Acceptance criteria	See
A. Description	The element consists of creeping formation (formation that plastically has been extruded into the wellbore) located in the annulus between the casing/liner and the bore hole wall.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along the casing annulus to prevent flow of formation fluids and to resist pressures from above and below.	
C. Design, construction and selection	1. The element shall be capable of providing an eternal hydraulic pressure seal. 2. The minimum cumulative formation interval shall be 50 m MD. 3. The minimum formation stress at the base of the element shall be sufficient to withstand the maximum pressure that could be applied. 4. The element shall be able to withstand maximum differential pressure.	
D. Initial test and verification	1. Position and length of the element shall be verified by bond logs: a) Two (2) independent logging measurements/tools shall be applied. Logging measurements shall provide azimuthal data. b) Logging data shall be interpreted and verified by qualified personnel and documented. c) The log response criteria shall be established prior to the logging operation. d) The minimum contact length shall be 50m MD with 360 degrees of qualified bonding. 2. The pressure integrity shall be verified by application of a pressure differential across the interval. 3. Formation integrity shall be verified by a LOT at the base of the interval. The results should be in accordance with the expected formation stress from the field model (see table 15.51 In-situ formation). 4. If the element has been qualified by logging, pressure and formation integrity testing, logging is considered sufficient for subsequent wells. The formation interval shall be laterally continuous. Pressure testing is required if the log response is not conclusive or there is uncertainty regarding geological similarity.	
E. Use	The element is primarily used in a permanently abandoned well.	
F. Monitoring	None	
G. Common well barrier	None	