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Abstract

During plug and abandonment (P&A) operations of petroleum wells there is often a need to remove casing in order to set competent barrier sealing in all directions. If the casing cannot be cut and pulled, a section milling operation has traditionally been the solution. The P&A is an expensive operation that offers no value creation, and the economic situation of the industry along with stricter regulations is causing an active search to strongly reduce rig-time and costs.

To address the situation, this thesis is compiled with an investigation into the P&A industry with a particular focus on the section milling operation and its requirements. The challenges of section milling have been discussed in depth with relations to performance enhancement, and statistics has been presented and compared with novel methods with the aim to define improvement potential. Investigated alternatives include perforate, wash and cement (PWC), upward section milling, melting, chemical degradation and the crushing of tubular.

The results show that the main disadvantage of the section milling is the swarf generation and handling of it with addition to HSE issues, violent vibrations and plug verification. The improvement of the cutters and the milling fluid has been presented as the most important factors for performance enhancement. The investigation into novel methods show that several technologies have the potential to substitute section milling and to significantly reduce duration and cost, with the largest documented potential being PWC's ability to cut the expected 24-day multiple casing section mill operation by 83%. However, further development is needed in order to refine the technology before it can replace section milling completely.

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Table of Abbreviations

API	-	American Petroleum Institute
ASV	-	Annulus Safety Valve
BHA	-	Bottom Hole Assembly
BOP	-	Blow Out Preventer
CBL	-	Cement Bond Log
CP	-	Centipoise
CS	-	Casing Shoe
EAC	-	Element Acceptance Criteria
ECD	-	Equivalent Circulating Density
FG	-	Fracture Gradient
ID	-	Inner Diameter
ISO	-	International Organization for Standardization
HP	-	High Pressure
HSE	-	Health, Safety and Environment
LOT	-	Leak Off Test
LWI	-	Light Well Intervention
MD	-	Measured Depth
MOU	-	Mobile Offshore Drilling Unit
N/D	-	Nipple Down
N/U	-	Nipple Up
NCS	-	Norwegian Continental Shelf
NORSOK	-	Norsk Sokkels Konkurranseposisjon (Competitive Standing of the Norwegian Offshore Sector)
NPD	-	Norwegian Petroleum Directorate
NPT	-	Non-Productive Time
OBM	-	Oil Based Mud
OD	-	Outer Diameter
P&A	-	Plug & Abandonment
PAF	-	Plug & Abandonment Forum
POOH	-	Pull Out of Hole
PP	-	Pore Pressure

PPG	-	Pounds Per Gallon
PP&A	-	Permanent Plug & Abandonment
PSA	-	Petroleum Safety Authority
PWC	-	Perforate, Wash & Cement
RIH	-	Run in Hole
RLWI	-	Riserless Well Intervention
ROP	-	Rate of Penetration
RPM	-	Revolutions per Minute
SFPM	-	Surface Feet per Minute
S/M	-	Section Mill
SP	-	Specific Gravity
SPF	-	Shots Per Foot
SSSV	-	Subsurface Safety Valve
TCP	-	Tubing-Conveyed Perforating
TOC	-	Top of Cement
TOF	-	Top of Fish
UKOOA	-	United Kingdom Offshore Operators Association
U/R	-	Under-ream
USIT	-	Ultra Sonic Image Tools
WBE	-	Well Barrier Element
WBM	-	Water Based Mud
WBS	-	Well Barrier Schematic
WH	-	Wellhead
WL	-	Wireline
WOB	-	Weight on Bit
WOC	-	Wait on Cement
WOW	-	Wait on Weather
XMT	-	Christmas Tree

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1 Introduction

All wells will have to be plugged and abandoned at one point in time. The P&A is a very expensive operation, taking on average around 35 days to complete on the Norwegian continental shelf (NCS) and adding no value creation. Many operators, due to the large costs associated, have put the P&A of their wells on hold, but the current regulations are making it harder to delay the operations. P&A is a technological underdeveloped area of the petroleum industry, but the decline in production of major fields on the NCS along with the bills that are stacking up has shed new light on the situation in recent years. Statoil's own goal is to get the average duration down to just one week, a challenge they deem achievable with new technology that can save significant amounts of time and thereby costs (Frafjord, 2015).

To meet the tremendous P&A challenge that lies ahead, existing technology needs to be refined while new and innovative methods are being developed. To address the issue, this thesis provides an investigation into the section milling operation. This is an operation where the casing is milled out in order to create a competent barrier in situations where the casing cementing is poor or the casing itself cannot be removed. The operation comes at a significant cost, taking one to two weeks to complete along with issues regarding milled steel particles, polluted mud and other rig challenges. The topics that is addressed includes:

- Description of P&A fundamentals and present-day status
- Understanding of the regulatory framework governing P&A
- Definition of permanent well barrier requirements
- An extensive investigation into the section milling technology and its challenges
- Investigation of novel methods to define improvement potential

The thesis is aimed at a reader which possesses basic knowledge about petroleum technology, but is new to P&A technology, challenges and requirements. Of the presented statistics, the time consumption is factual while the costs are estimated.

2 P&A Fundamentals

The Norwegian petroleum industry is still relatively young, with around 50 years having passed since petroleum activities commenced on the NCS. Today many of the early fields are still producing, with wells still being drilled. However, many large fields are also reaching the end of their productive life. As illustrated in figure 1, Statoil expect a significant increase in wells with cease of production in the years to come.

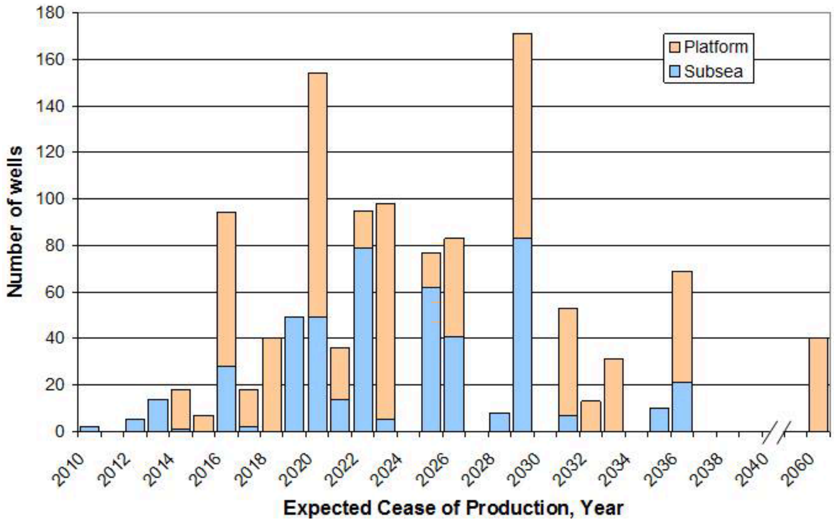


Figure 1: Estimated cease of production, Statoil (Eshraghi, 2013)

It is reported by the Norwegian Petroleum Directorate that as of the 1st of march 2015 there are 2134 wells on the NCS that will, at one point, be plugged. This is just the existing wells of today, and in addition comes all production and injection wells that will be drilled due to new developments and/or increased oil recovery (IOR) measures. These are all wells that the oil companies are legally required to plug after cease of production. Figure 2 shows an estimation of the wells that will be plugged by Statoil in the coming years, again with a significant increase from 2015. As a result, the market of plug and abandonment is expected to have a substantial growth the forthcoming years.

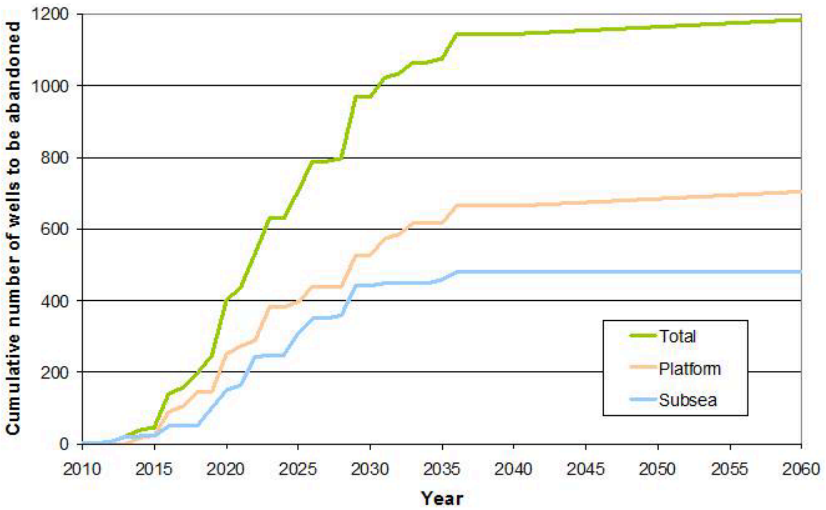


Figure 2: Cumulative number of wells to be plugged by Statoil (Eshraghi, 2013)

In 2014 it was presented by Martin Straume, leader of the Norwegian Oil & Gas P&A Forum, a time estimate of the plugging of the wells on the NCS. Based on an estimate of 3000 wells to plug, along with a 35-days average for each well and with 15 rigs working fulltime he estimated that it would take approximately 20 years to successfully plug them. However, based on the activity the last ten years (144 wells/year), it is estimated that another 2880 wells would have been drilled during this period, which means that it would take 15 rigs a total of 40 years to plug all of the wells. Assuming the current technological status of the industry persists, the final bill could be as much as 876 billion NOK, which is split 22% by the operator and 78% by the government (Straume, 2013).

Needless to say, the P&A industry has a big potential for improvement, and presents itself as an industry worth billions and that Norway could have the technological capability to lead.

2.1 The Definition of Plug & Abandonment

The operational term P&A is a collective expression used for sealing off a wellbore through the setting of a series of effective barrier elements across the entire wellbore cross-section. These operations of permanently sealing of a well will take place on the end of a wellbore’s life cycle, and so to prepare the well for abandonment on an eternal perspective.
Figure 3 is a simple presentation on what a wellbore may look like with the different barriers in place.

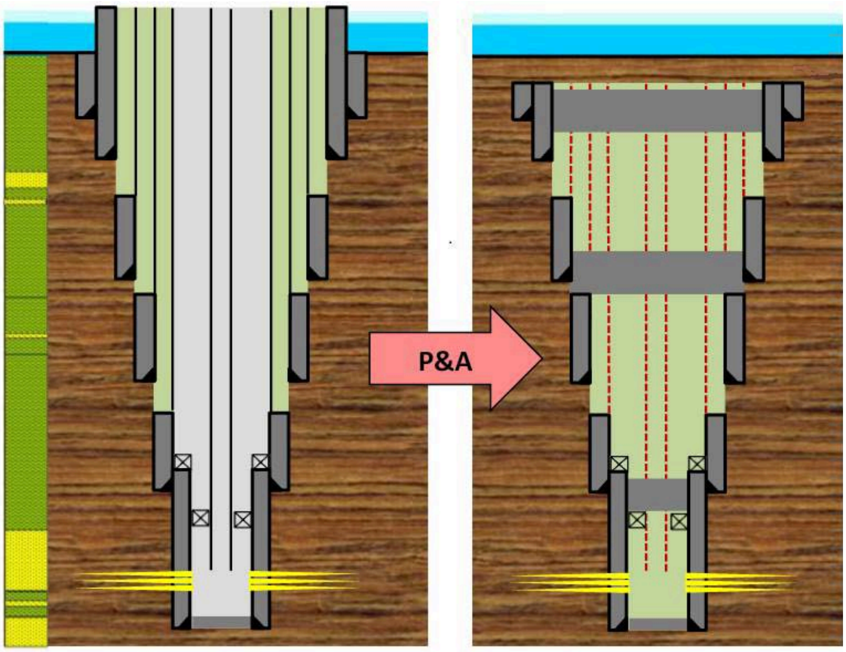


Figure 3: Permanent abandonment illustration (Malin Torsæter, 2015)

The Norwegian Standards for the Petroleum Industry NORSOK D010 – Well Integrity in Drilling and Well Operations, serves further definitions on critical terms of these operations. The NORSOK standard itself is discussed further in section 3.3.5 of this thesis.

- **Plugging:** Operation of securing a well by installing required well barriers.
- **Temporary abandonment – with monitoring:** Well status, where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested.
- **Temporary abandonment – without monitoring:** well status, where the well is abandoned and the primary and secondary well barriers are *not* continuously monitored and *not* routinely tested.
- **Permanent abandonment:** Well status, where the well is abandoned permanently and will not be used or re-entered again.

(NORSOK D-010 Rev.4, 2013)

2.2 Temporary Abandonment

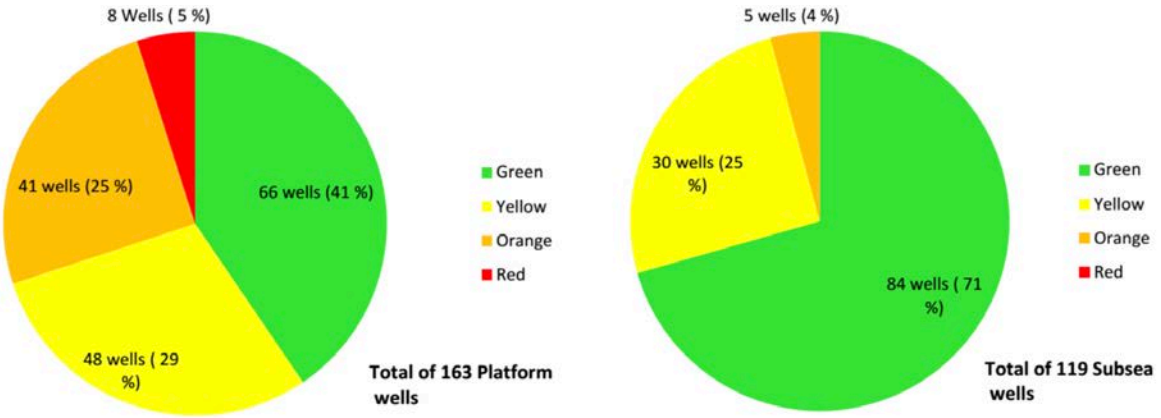
If an operator wishes to abandon a well that it may have future plans for, it can choose to temporary abandon the well. Temporarily abandoned wells are defined as all wells/wellbores, with the exception of active development wells (production/injection wells) and wells that have been permanently plugged and abandoned pursuant to regulatory requirements (Petroleum Safety Authority Norway, 2011).

The reason for temporary abandoning a well may be numerous, but will often be due to a prolonged wait for the project, for example to convert the well from exploration to development or due to a long shut-down. In any case, the temporary abandonment shall be completed in such a way that it is possible to re-enter the well in a safe manner for the entire duration of the temporary abandonment (NORSOK D-010 Rev.4, 2013)

If the well is implemented with a continuously monitoring programme, there is virtually no maximum abandonment period for the well (NORSOK D-010 Rev.4, 2013). However, in 2014 it was implemented a new regulation saying that no *exploration wells* commenced after 01.01.2014 shall be temporary abandoned more than two years (Dahle, 2014). If there is no monitoring of the well the maximum period for any well is set to three years, and with a program for visual observation of which the frequency shall be substantiated by a risk assessment and shall not exceed one year.

It is a concern that operators will choose a long period of temporary abandonment over the added cost of a permanent solution. In 2011, the Petroleum Safety Authority (PSA) collected documentation from eight operators on the NCS with regards to well integrity status and the companies' future plans for their temporarily abandoned wells. An analysis of the documentation revealed that 74 of the 193 (38%) temporarily abandoned wells were in the well integrity categories “red, orange and yellow”, according to the Norwegian Oil Industry Association's (OLF's) guideline no. 117. The guideline speaks of different degrees of barrier failure, further described in figure 4. In addition, the analysis revealed that several of the wells in question had been temporarily abandoned over a long period of time (Petroleum Safety Authority Norway, 2011).

This is still a problem today, illustrated by figure 4 showing the temporarily abandoned wells of 2014. Here it can be seen that while 29% of the total 119 subsea wells had a status with a degraded barrier or worse, a more disturbing 59% of the 163 platform wells had the same status.



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

Figure 4: Temporarily abandoned wells, 2014(Petroleum Safety Authority, 2015)

2.3 Permanent Abandonment

The predominantly abandonment method of which this thesis will involve is the permanent abandonment, which will be thoroughly discussed throughout the thesis. A well that is permanently plugged is abandoned in an eternal perspective, which means that it will never be re-entered again.

To achieve permanent plug and abandonment (PP&A) is both challenging and costly, with completion being removed and a series of permanent well barrier elements set to seal the wellbore and leave no surface evidence of the well’s existence. Suitable materials and proper setting depths needs to be established taking into account the effects of any foreseeable chemical and geological processes, which needs to be verified and documented (NORSOK D-010 Rev.4, 2013).

2.4 Historical background of P&A

Many technologies or methods that we use in our modern lives have hardly changed for a long time. The general idea of the internal combustion engine is now over 100 years old, and so is the basic methodology that is used in P&A. Back then, as it is today, cement and drilling mud was the basic materials used to plug the wells. It has, of course, been improved in countless parameters, but the overall methods remains similar now to what was used back in the old days.

When the modern oil and gas drilling, as it is perceived today, began in Pennsylvania in 1859, there was no regulation with regards to the treatment of the well at the end of its useful lifetime. The wells could be “temporarily abandoned” while the operators waited for the price of oil to rise to a profitable level, an increase that in some cases never came. The result of this was that the well could be left as an open hole in the ground (Department of Environmental Protection Bureau of Oil and Gas Management, 2000).
As the environmental and safety implications of incorrectly abandoning the wells had not been established, the advancement in P&A technology trailed behind the constant advancement in drilling. However, as more and more dry holes were abandoned, several states began to see the need to establish a standard for the proper abandonment of oil and gas wells.

It was not until the 1890s that Pennsylvania started to regulate that wells should be plugged, and requirements were designed to protect production zones from flooding by fresh water. These regulations were first and foremost designed to protect the gas and oil resources, and not the environment itself. (Technology Subgroup, 2011)

As wells were being drilled constantly without much information with regards to location and construction of them, a demand for a proper regulatory organ grew stronger. In 1919, the Texas Railroad Commission was given the authority to regulate well plugging (Technology Subgroup, 2011), and became the first documented institution in the world.

Other states progressed in a similar way, and as a result thousands of wells prior to the 1950s was either poorly plugged or not plugged at all. When the regulations first started to demand cement, the regulations were so vague that wells were plugged with whatever could serve as to hold a sack of cement. Materials included brush, wood, rocks, paper, linen sacks and a variety of other items (Technology Subgroup, 2011). As a result, many old wells today are leaking quite large quantities of greenhouse gases out into the atmosphere due to poor or missing plugging (Vaidyanathan, 2014).

As the clock ticked and flaws were found, the regulatory fortunately framework evolved. Table 1 shows the progression of the rules implemented and the objectives behind them in the subsequent years of the industry.

Table 1: Historical development of P&A, with regards to the regulatory framework (Toro, 2013)

Year	Article	Objective
1919	Dry or abandoned wells shall be plugged in such a way as to confine oil, gas, and water in the strata in which they are found and prevent them from escaping into other strata. It shall be the duty of the supervisor and his deputies to supervise the plugging of all wells.	To give a general objective of P&A operations, and to assign the responsible parties in charge of the operations.
1934	Plugging operations should be started within 20 days on all dry and abandoned wells, or when production operation ceased. Cement is required to be circulated through tubing or drill pipe across these producing formations. Non-producing formations, where no high-pressure gas sands or commercial water sands were encountered, could be plugged with mud-laden fluid.	To establish a time limit for the operation. Also to protect the producing formations from water flowing and suggest the first plugging material for well abandonment.
1957	In a dry hole, the short string of surface casing must be cemented in its entirety, and the deepest freshwater zone must be protected by a cement plug covering this water zone to at least 50 feet above and below the zone.	A change in focus is implemented, protecting the nearby environment by isolating freshwater sands.
1974	Plugging operations on each dry or inactive well shall be commenced within a period of one year after the drilling or operations cease, and shall proceed with due diligence until it is completed. Plugging operations on delinquent inactive wells shall be commenced immediately unless the well is restored to active operation. For good cause, a reasonable extension of time in which to start the plugging operations may be granted pursuant to the following procedures.	Implemented specific plugging requirements to protect usable quality water from pollution, and to isolate each productive horizon.

2.5 P&A in Norway

The actual start of the Norwegian oil adventure is defined as a gas discovery in the Netherlands in 1959. Up until this point there was little interest for the North Sea, but the discovery sparked an interest for the potential of reserves (Ministry of Petroleum and Energy, 2014). The true milestone in Norwegian petroleum history had to wait another 10 years, when Ekofisk was discovered in 1969. It started to produce in 1971, and was followed by several large discoveries shortly thereafter such as Statfjord, Oseberg, Gullfaks and Troll. The finding of these giants inevitably formed what we now know as the NCS and eventually fuelled the Norwegian economy to a new level. (Ministry of Petroleum and Energy, 2014)

Today, well over 40 years after the start of production the industry has become the highest value creator in Norway, and has in many ways defined who we are. There are 1070 companies in the Norwegian petroleum industry, giving 453 billion NOK of revenue in 2013 and with 122 000 direct employees (Norheim, 2015). In 2012, Norway was the world's third largest gas exporter, and the tenth largest oil exporter (Ministry of Petroleum and Energy, 2014).

However, as figure 5 shows us, the peak of Norwegian petroleum production has long since passed and we cannot rely solely on huge productions from the giant fields anymore. The trend has become to develop and produce much smaller fields, with new technology and cleaner, smarter production and consumption.

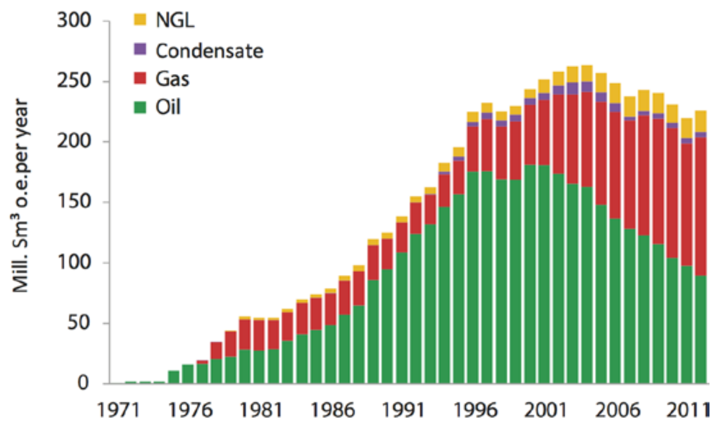


Figure 5: Total Petroleum Production(Ministry of Petroleum and Energy, 2014)

Although the regression in production has generated doubt in some people, raising questions to how long the oil will last, it is important to emphasise that the Norwegian petroleum industry is not fading away. Only 44% of the projected recoverable resources on the NCS have been produced, and as the forecast in figure 6 shows the production of petroleum in Norway is expected to be of a major quantity in many years to come (Ministry of Petroleum and Energy, 2014). The answer is of course to be efficient, and the industry today is working hard at making the most of the resources and maximising profit from it. This has fuelled innovative technologies that are exported to the global industry.

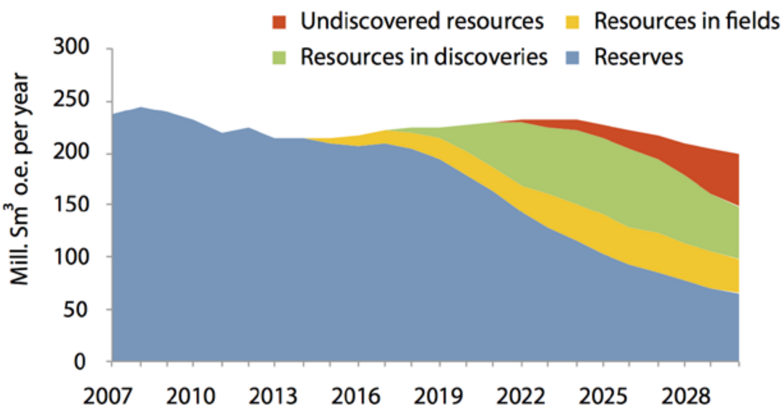


Figure 6: Production forecast for oil & gas(Ministry of Petroleum and Energy, 2014)

From 1966 to May 2013, a total of 5163 wells were drilled on the NCS. Of these, 3733 were development wells used for production, injection and monitoring, and 1430 for exploration. That is an overall average of 109 wells per year. (Straume, 2013)

Traditionally, the P&A portion of petroleum wells has not been a big focus in the Norwegian petroleum industry. It has been thought of as an expensive and time-consuming operation, and has therefore been put off as long as possible. However, the sheer number of wells created over the last 49 years, the decline in production and the immense cost of abandoning them has changed this. As a result, an increase in the focus of the P&A challenges can be seen today.

In 2009 the Plug and Abandonment Forum (PAF) was formed, led by ConocoPhillips and with nine members. In 2014 there were sixteen members and two observers, with the common goal of preparing for the enormous P&A challenge that lies ahead (Statoil , 2014).

3 Regulatory framework of P&A

To provide the reader with an understanding of which regulatory bodies that controls the P&A activities on the NCS and how they work together, this chapter will deal with the regulatory framework that surrounds the industry.

3.1 Norwegian State Organization of the Petroleum Activities

The Norwegian Parliament (Stortinget) is the formal head of the petroleum activities being conducted in Norway with regards to the legal framework. It serves as the top level, and has the authority to adopt legislation as well as to approve major development projects and issues that involves fundamental principles. The Parliament will also supervise the Government itself as well as the public administration (Ministry of Petroleum and Energy, 2014).

While the Parliament acts like the executive chief of the legal framework, the Government itself sits with the executive authority concerning the petroleum policy, and will answer the Parliament in this regard.
The ministries, the underlying directorates and supervisory authorities assist both the Parliament and the Government. Each of these has different responsibilities that shall ensure that the way the petroleum activities are being done line up with the guidelines given by the top authority (Ministry of Petroleum and Energy, 2014). The layout of this structure, combined with the ministries with their respective responsibilities can be perceived in figure 7.

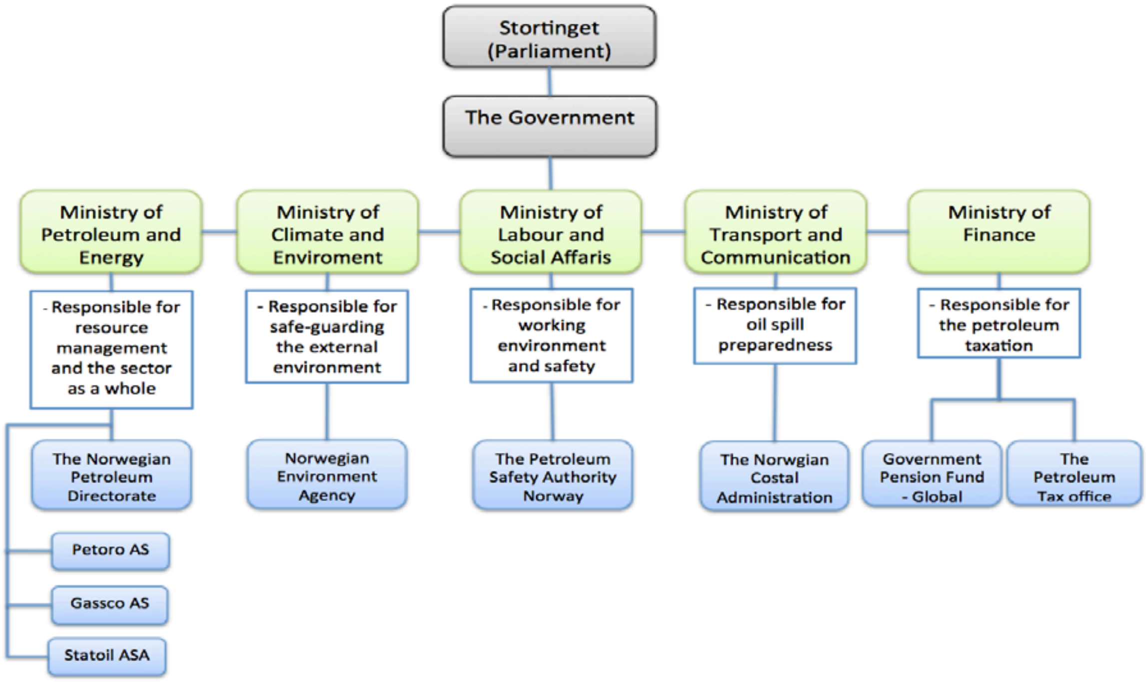


Figure 7: The State Organisation of the petroleum activities(Ministry of Petroleum and Energy, 2014)

3.2 The Petroleum Safety Authority

The Petroleum Safety Authority (PSA) is a Norwegian regulatory body that controls the regulatory responsibilities as regards to safety, emergency preparedness and working environment. As of the 1st of January 2004, PSA was demerged from the Norwegian Petroleum Directorate (NPD), started its function as an independent, government regulatory body, and is now subordinate to the Ministry of Labour and Social affairs.

Their authority covers each face of operations, including planning, engineering, construction, operation and eventually deconstruction (Petroleum Safety Authority Norway, 2015).

Figure 8: The PSA icon (Petroleum Safety Authority Norway, 2015)

Safety is a main aspect in PSA's terminology, and it embraces three categories of loss - human life, health and welfare.

In their own words, they state their goal as the following:

"The Petroleum Safety Authority Norway will set the terms for health, safety, the environment and emergency preparedness in the petroleum sector, follow up to ensure that industry players maintain high standards in this area, and thereby contribute to creating maximum value for society." (Petroleum Safety Authority Norway, 2015)

The three specific duties given by the government to PSA is listed in PSA's website, and is as follows:

- *Through our own audits and in cooperation with other health, safety and environmental (HSE) regulators, to ensure that the petroleum industry and related activities are supervised in a coherent manner.*
- *To supply information and advice to the players in the industry, to establish appropriate collaboration with other HSE regulators nationally and internationally, and to contribute actively to conveying knowledge about HSE to society in general.*
- *To provide input to the supervising ministry on matters being dealt with by the latter, and support with issues on request.*

(Petroleum Safety Authority Norway, 2015)

The PSA will daily supervise all players in the Norwegian petroleum industry: as of 2015, a staff of 170 people supervise more than 75 permanent installations and over 40 mobile units, 8 major land-based petroleum plants, 300 subsea installations and about 14 000 km of oil and gas pipelines (Petroleum Safety Authority Norway, 2015). Everything is, of course, *not* supervised each minute of the day – but priorities is given to those areas that have proved to have the highest risk.
Nevertheless, it is comprehensive work, and to do it as best as possible the professional competence of PSA is divided into six disciplines:

- Drilling and well technology
- Process integrity
- Structural integrity
- Logistics and emergency preparedness
- Occupational health and safety
- HSE management

Each of these disciplines is headed by a discipline leader, of who is responsible for the quality of the work along with personnel, expertise, development and resource management. For P&A activities, the discipline of *Drilling and Well Technology* is the regulatory body in Norway.

Each year PSA publishes a list of their special priorities areas the following year, to give a clear statement as to what is the main priority. In 2015, these are:

- Safe late life
- The far north
- Management responsibility
- Barriers

3.3 Legal Framework Hierarchy for the Norwegian Petroleum Industry

Being based out of the kingdom of Norway, the implementation of a legal framework in the petroleum industry has to be based on the fundamental principles and set models that are the constitution of Norway. Succeeding the constitution itself are other relevant acts that apply to the industry, followed by the levels shown in figure 9, which clearly dictates the descending hierarchy.

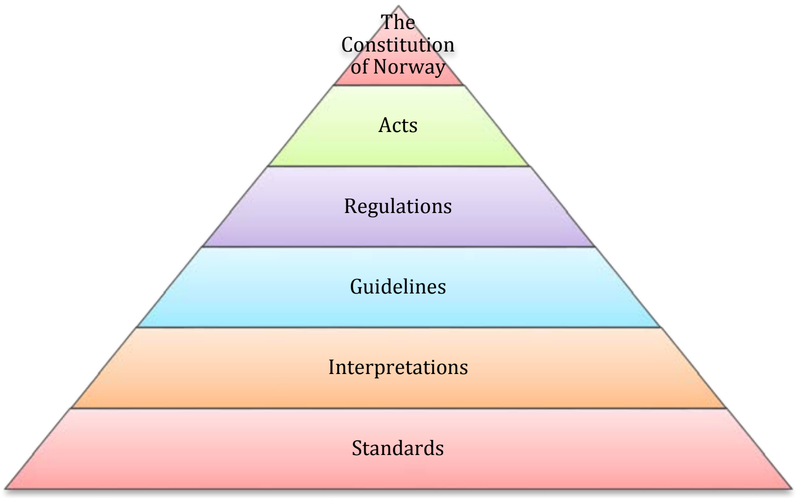


Figure 9: Legal hierarchy pyramid for the Norwegian Petroleum Industry

3.3.1 Acts

As previously discussed - the authority to implement, change and suspend acts in Norway lies with the parliament. After the parliament has adopted an act, the government will often draw up further rules in the form of central government regulations that explain the act in more detail (Storm-Paulsen, 2013).

Acts in the petroleum industry falls under PSA's area of authority. Some important examples include:

- Petroleum Activities
- Working environment
- The Fire and Explosion Prevention Act
- The Electric supervision Act
- Wage agreements application
- The Svalbard Act

3.3.2 Regulations

Any modern corporation will expectantly agree that HSE is the most important aspect of any operation or project undertaken. The regulations are built the same way, with the most important regulation being the framework HSE.

The statement under chapter 1, section 1: "Purpose" of the framework HSE clearly show that this is the case:

"The purpose of these regulations is to

a) promote high standards for health, safety and the environment in activities covered by these regulations,
b) achieve systematic implementation of measure to comply with requirements and achieve the goals laid down in the working environment and safety legislation,
c) further develop and improve the health, safety and environmental level."

(Petroleum Safety Authority Norway, 2013)

Other regulations will in a large scale involve the working environment itself. They include regulations regarding management, facilities, and activities as well as technical and operational regulations, amongst others. It is important to stress that the regulations themselves does not specify in detail how the objectives should be achieved.

For technical purposes involving P&A, the regulations will be found in the *Activities* – and the *Facilities* regulations.

3.3.3 Guidelines

The guidelines are meant to serve as an addition to the regulations, and will demonstrate how the provisions in the specific regulations can be met. They are also used to give some extra information of the legislation.

The guidelines mark a significant alteration in the legal framework hierarchy pyramid, in that they themselves and the succession levels are not actually legally binding.

3.3.4 Interpretations

The Oxford Dictionary defines an interpretation as the action of explaining the meaning of something: *"the interpretation of data"*. In the sense used in this thesis, the interpretations is a statement from the authorities on how the legislation or provisions in the regulations should be understood, and so to guide the acting party to follow the regulations in a responsible manner (Petroleum Safety Authority Norway, 2015).

3.3.5 Standards

The standards represent the last level in the pyramid. Guidelines will often refer to specific standards as a way to meet the requirement set by the regulations.

In its essence, a specific standard is an agreed way of doing something. This "something" can be of large variety, ranging from managing a small process to making an entire product. Standards are knowledge, and are powerful tools in the quest to drive innovation forward and to keep increasing productivity, safety and welfare in an organization.

There will always be different ways of doing similar things, and so the different regions of the world employ different standards. In America, they commonly employ American Petroleum Institute (API) or the American Gas Association (AGA) as standards to regulate the operations in the oil industry.

Another well-known standard is the International Organization for Standardization (ISO), which have been developing standards for a large variety of fields since 1947 (Standard Norge, 2015).

The primary standard used on the NCS is the NORSOK standard, and specifically for P&A purposes, it is referred to NORSOK D-010 – Well Integrity in Drilling and Well Operations.

3.3.5.1 NORSOK

In the early 1990s, the Norwegian petroleum industry saw an alarming incline in the cost of offshore development as well as a reduction in the oil price. The industry therefore saw a need for change, and wanted to create an initiative to research alternatives. The initiative was named NORSOK, and was set in motion by the former minister of industry, Finn Kristensen in 1993.

The main purpose of the initiative was to identify improvement potentials in the cost of field developments and petroleum policies, and so to make the NCS more competitive. This included a 40-50% decrease in cost and lead-time over a five-year period, as well as to maintain the position of being the safest oil industry in the world (Johansen, Saga petroleum, Statoil, Norsk Hydro, & NTS, 1996).

Up to this point, the Norwegian petroleum industry mainly used standards originated from the United States. Being based on an entirely different part of the globe, the standards were not ideal for the type of environment met on the NCS. Hence, many alterations and additions had to be made constantly to try to adjust them to the new environment and technical requirements. In addition, a survey of the time exposed that there were around 2000 different standards currently in use in the petroleum and natural gas industry in Europe (Johansen, Saga petroleum, Statoil, Norsk Hydro, & NTS, 1996). This vast number of different standards could easily lead to confusion, prolonged delivery and high costs.

The NORSOK initiative included seven different work groups, one of which were to deal with standardization. This group would later go on and develop the NORSOK Standards. The standards were shaped with the following principles at heart:

- Define an acceptable level of safety
- Make extensive references to international standards
- Specify functional requirements where possible
- Include variation
- Control to secure defined interfaces and exchangeability
- Describe “good enough” requirements
- Be short

(Johansen, Saga petroleum, Statoil, Norsk Hydro, & NTS, 1996)

Today, NORSOK continues as an industry initiative to add value, reduce cost and lead-time and eliminate unnecessary activities in offshore field developments and operations (NORSOK D-010 Rev.4, 2013)

3.3.5.2 NORSOK D-010

The NORSOK standard of primary interest for this thesis is the D-010 – Well Integrity in Drilling and Well Operations. It is currently in revision 4, dated June 2013, and has a specific section on abandonment activities.

The scope of the standard is to focus on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities and operations (NORSOK D-010 Rev.4, 2013).

3.3.5.3 NORSOK & Costs in P&A

Although the claimed initiative of NORSOK is to reduce overall costs, is not seen to be the case in every aspect of the petroleum industry.

In the period of 2000-2004, the average P&A operation on the NCS took around 16 days. As it can be seen in figure 10, this number takes a steep climb in the years from 2004-2010, and averages around 35 days. This average is still the case in 2014, with some wells taking as much as 60 days to successfully P&A (Statoil , 2014). With an estimated rig rate from Statoil of $300 000 per day, this average increase in time consumption represents an added cost of $5 700 000 in rig rate alone.

It is important to emphasise that this average is generalized, and as the reader will see in chapter 7, the P&A operation is comprised with many possible unforeseen events that can radically change the duration of an operation.

It is a belief that the implementation of NORSOK D-010 rev. 3 in august of 2004 brought an increased attention to the safety issues that in turn caused the average operation to increase its duration. However, several changes have happened since 2004 and so NORSOK cannot take full responsibility for the increase. Still, it is an interesting comparison to perceive when the publicity of rev. 3 is compared against the increase in average operational time in figure 10.

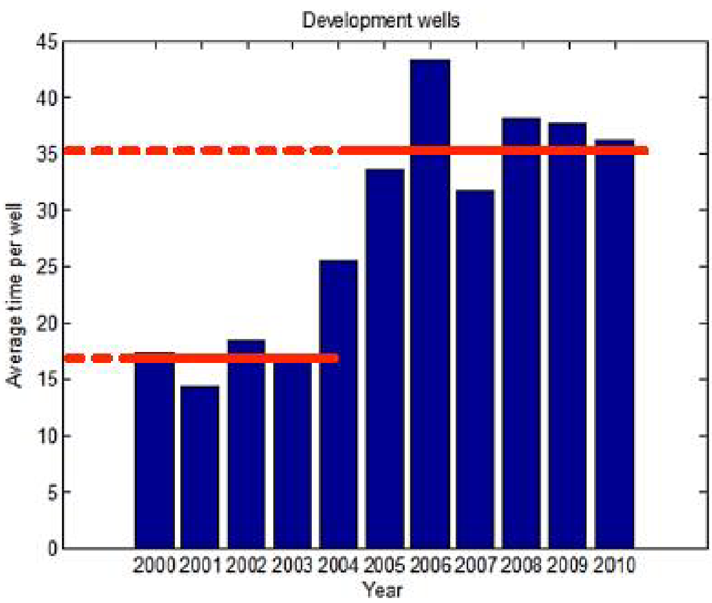


Figure 10: Average operational time of P&A per well (Statoil , 2014)

3.3.5.4 Additional P&A Standards in the North Sea

The North Sea is divided into sectors by the United Kingdom, Norway, Denmark and Holland. Similar for these countries are that they will all hold the owner or the last operating company on a specific field responsible in a manner of any leaks from an abandoned well, in addition to any subsequent clean up that might have to be done.
This means that the P&A operations that are undertaken in the North Sea are designed by the regulations or standards of the specific region.

The sector of the United Kingdom (UK) is performing the operations with accordance to guidelines set by the UK Offshore Operators Association (UKOOA): Guidelines for Suspension and Abandonment of Wells. The sector of the Netherlands is according to guidelines by Dutch mining authority, and of course, the Norwegian sector has already been discussed.

Although there are several differences in practice on the sectors, all of them essentially guide the operator towards the same goals by:

- Prevention of hydrocarbon leakage to surface
- Prevention of hydrocarbon movement between different strata
- Prevention of contamination of aquifers
- Prevention of pressure breakdown for shallow formation
- Removal of any snagging hazards for vessels

(Liversidge, Taoutaou, & Agarwel, 2006)

4 Well Barriers

In all aspects of operations, *safety* is the main concern. Any well can be traitorous, and so it is employed barriers to a well in order to prevent an uncontrolled situation. NORSOK rev. 3 defines a well barrier as an envelope of one or several dependent barrier elements that are preventing fluids or gases from flowing unintentionally from the formation, into another formation or to the surface (NORSOK D-010 Rev. 3, 2004).

In an ideal world, it would be the case that each well barrier element (WBE) should be more than enough for its purpose. However, it is known that physical elements may have a tendency to develop faults. To ensure safety in all cases, it is therefore assumed that a single WBE are not able to withstand a flow from one side to the other.

Although it is normally operated with multiple barriers in an envelope, there are cases where NORSOK only demands one well barrier. These cases are listed in table 2.

Table 2: Numbers of barriers (NORSOK D-010 Rev.4, 2013)

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 barriers	d) Hydrocarbon bearing formations e) Abnormally pressured formation with potential to flow to surface

4.1 Swiss Cheese Model

Today it is recognized that an accident that occurs in a complex system is the result of multiple factors, of which each may be necessary but are only collectively sufficient to produce the accident itself. This is the basic idea behind the Swiss cheese model, contributed by professor James Reason in 1990 (Reason, Hollnagel, & Paries, 2006). It has its name from the similarity to several layers of Swiss cheese put behind one another. In this thesis, each slice represents a defensive layer, a WBE. While each slice may contain holes, or errors, the next slice features a hole in a different place, and the defence is intact. This is illustrated in figure 11.

The latent conditions of a system are the inevitable “resident pathogens” within the system (PMC, 2000). These faults stem from decisions within design, placement methods, procedures and top-level management. Active failures, on the other hand, are the wrongfully committed acts done by people that are in direct contact with the system. This may include accidents, but also deliberate acts done according to or in violation of procedural violations (PMC, 2000).

For a fatal error to occur, the system needs to be flawed in such a way that all the holes are aligned, and thus the error can be allowed to complete its trajectory in figure 11. The more slices to pass, the more unlikely it is for the trajectory to occur. It is crucial for the well barriers involved in P&A that they not develop this trajectory, but maintain the defence in depth and protect workers, equipment and of course the environment.

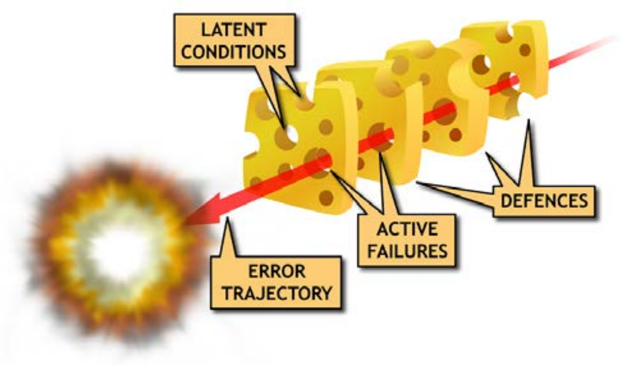
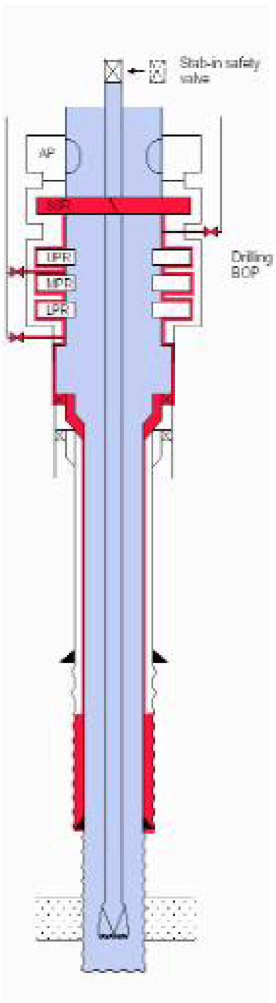


Figure 11: Swiss Cheese Model (Aireform, 2013)

4.2 Well Barrier Types

Before any operation or activity is started, a description of the well barrier has to be made with accordance to NORSOK D-010. To give a graphical representation of the well barrier it is used well barrier schematics (WBS’), like the example illustrated in figure 12.

5) Drilling, coring or tripping – Shearable drill string



1) Well barrier elements	See Table 2)	3) Comments
Primary well barrier		
1. Fluid column	1	
Secondary wellbarrier		
1. Casing cement	22	
2. Casing	2	Last casing set
3. Wellhead	5	
4. High pressure riser	26	If installed
5. Drilling BOP	4	

4) Note

Legend:

1. *This describes the name of the WBE(s)*
2. *A complete description of general acceptance criteria for this WBE is found in Clause 15 which contains a library of WBE acceptance criteria tables.*
3. *This table column is used to describe comments.*
4. *The place can be used for describing additional requirements and guidelines. For example a description of compensative measures if there exist common WBEs.*
5. *The illustration shows the primary well barrier in its normal working stage, while the secondary well barrier is shown in its ultimate stage. This stage often described with a closed shearing device.*

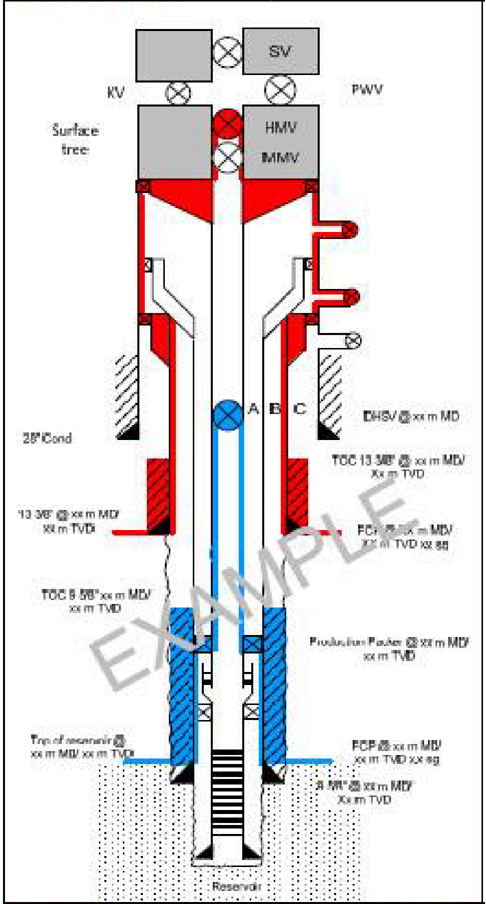
Figure 12: Simple WBE (Explanatory) (NORSOK D-010 Rev. 3, 2004)

It is predominantly spoken about primary and secondary well barriers, each with their own set of WBEs to build up a well barrier envelope. The elements in each envelope, though permanent, may change for each case dependent on the direction of flow in the well. However, a secondary well barrier may never be used as a primary well barrier for the same reservoir. Still, it can be used as a primary for a shallower formation given that the well barrier itself is constructed to meet the requirements that are needed for both formations.

In the WBS', primary well barrier is indicated with a blue colour, and secondary well barrier with a red colour. On the side of the illustration we can see a written statement of which elements are included in the well barriers. In figure 12, the fluid column itself acts as the primary barrier, while in figure 13 it is more mechanical or permanent elements.

NORSOK D-010 itself defines the primary well barrier as the first well barrier that prevents flow from a potential source of inflow, and the secondary well barrier as a back-up should the primary well barrier fail (NORSOK D-010 Rev.4, 2013).

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.

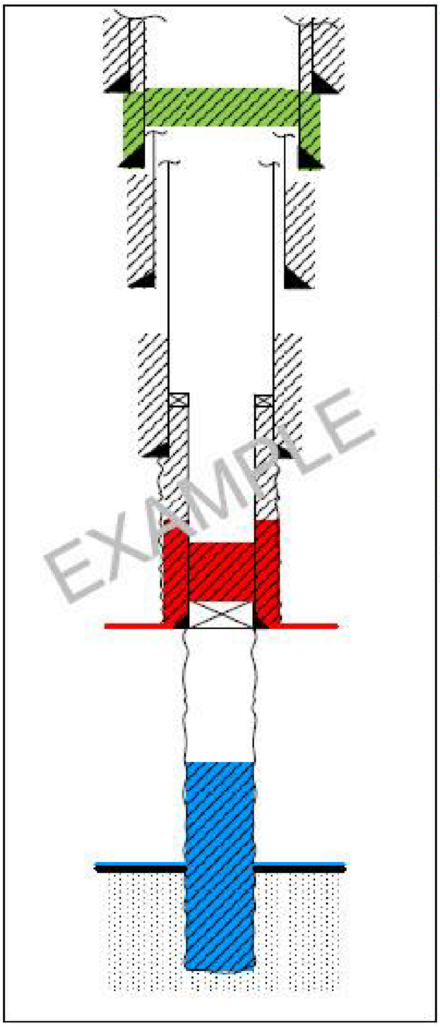
Nomenclature:
PT: Pressure test
IT: Inflow test
FCP: fracture closure pressure
XLOT: extended leak off test
AC: acceptance criteria

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 13: WBS example (NORSOK D-010 Rev.4, 2013)

The physical barriers of which this thesis revolve around will be the barriers that are set in place in order to secure the well for an abandonment phase. Figure 14 is an illustration on what this may look like, and is a fabricated illustration of a permanent abandonment in an open hole wellbore.

The additional green well barrier to the primary and secondary is an “open hole to surface well barrier”. This well barrier is a shallow barrier set to isolate the exposed hole to the external environment. In a permanent abandonment, available soil or bits of formation may be placed on top so that there is no visible evidence of the well’s existence.



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 14: WBS: Permanent abandoned well, open hole (NORSOK D-010 Rev.4, 2013)

In many situations, the wellbore may go through multiple reservoirs. If this is the case, it is required to install plugs between each of the reservoirs if these are in different pressure regimes. If they are within the same pressure regime, as seen in figure 15, they may be thought of as one reservoir and normal practice can be followed.

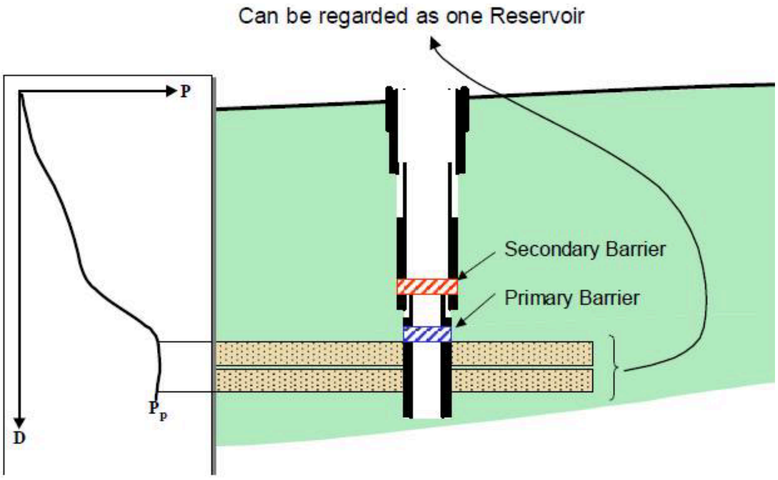


Figure 15: Multiple reservoirs within the same pressure regime (NORSOK D-010 Rev.4, 2013)

4.3 Well Barrier Requirements

NORSOK D-010 states that every element used for the intention of abandoning a well shall be designed in such a manner as to withstand any foreseeable load, environmental condition and chemical process of which they may be exposed to during the abandonment period. The following list is the characteristics a permanent barrier shall possess:

a) Provide long term integrity (eternal perspective);
b) Impermeable;
c) Non-shrinking;
d) Able to withstand mechanical loads/impact;
e) Resistant to chemicals/substances (H_2S, CO_2 and hydrocarbons);
f) Ensure bonding to steel;
g) Not harmful to the steel tubulars integrity

(NORSOK D-010 Rev.4, 2013)

Having these characteristics is thought of as being the best possible way to make a proper and efficient barrier element, and so to ensure the prevention of gas and fluids to migrate to the surface. To ensure good sealing it is important that the well barriers extend across the entire cross section of the well. This means that the well barrier element placed inside the casing needs to be placed adjacent to an interval where there is a good seal outside the casing both in a horizontal and a vertical direction. This optimal situation is illustrated in figure 16.

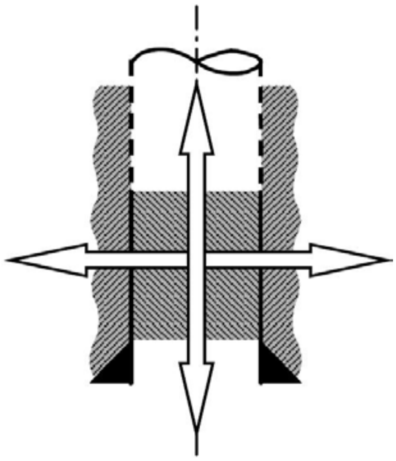


Figure 16: Permanent well barrier, sealing in all directions (NORSOK D-010 Rev.4, 2013)

Any malfunctions in the barrier elements, or downhole conditions not taken into account, may eventually lead to leaks. Figure 17 illustrates how inferior cement quality can lead to different leakage pathways in an abandoned well with a cased-hole cement plug.

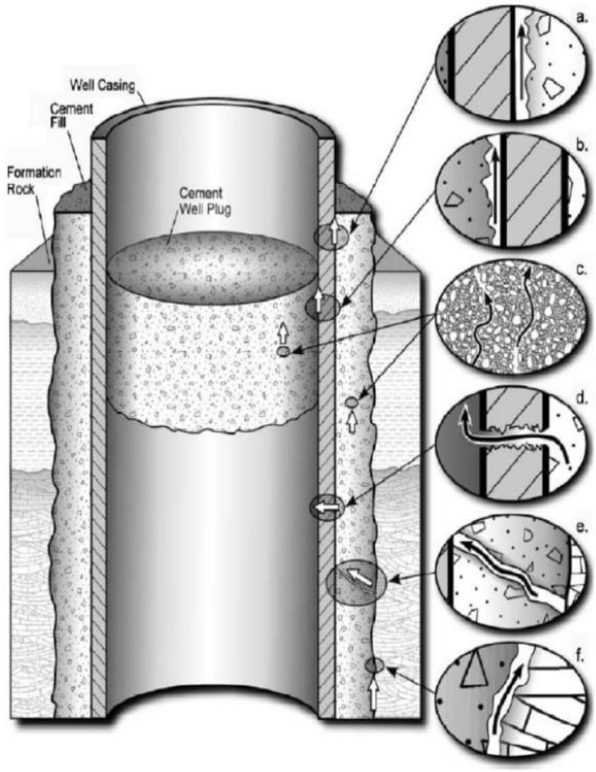


Figure 17: Possible leak scenarios (Fjelde, Spring 2014)

These malfunctions can be traced back to the NORSOK D-010 criteria's for a permanent plug. Example (a) shows a leak between cement and the outside of the casing, displaying that the cement has not achieved a proper bond to the steel, and the cement may also have shrunk. At (b) it can be perceived exactly the same thing on the inside of the casing. Example (c) shows a leak through the cement plug itself, which has been set with a cement mix that is permeable and therefore creates a pathway through the plug body. At (d) the leak can be seen through the casing body. This may be due to local casing wear that was not looked into, and/or the cement may be harmful to the steel and is corroding it (pitting) At (e) there is a fracture in the cement, which can have been caused movement in the formation or a force of some other kind to break up the cement and cause it to leak. And finally at (f) there is a leak between the cement outside casing and the formation, where there has been poor bonding to the formation and perhaps shrinkage.

4.3.1 Length Requirements

To help ensure a sufficiently good WBE, NORSOK D-010 suggests length requirement for the element. For the internal WBE, it is stated:

"*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.*"

(NORSOK D-010 Rev.4, 2013)

For the external WBE it is also required 50 m with formation integrity at the bottom of the interval, although it will be approved using a minimum of 30 m intervals it the casing cement is verified by logging – a technique described in section 4.4.2 of this thesis.

The referred "EAC 24" in the quote above is a reference to the Element Acceptance Criteria (EAC), table 24 in NORSOK D-010 rev. 4. For the interested reader it provides extensive acceptance criteria's for the cement plug. Relevant for this section is the following table 3, extracted from table 24 – cement plug in NORSOK D-010 rev. 4 itself. It explains the length requirements for a cement plug in different scenarios.

Table 3: Length criteria's for a cement plug (MD=Measured Depth) (NORSOK D-010 Rev.4, 2013)

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.

4.4 Verification & Evaluation

As a WBE element is installed in a well it is a carefully planned process, even though the actual setting of the cement plug is not defined as the most complicated process of a P&A operation. Even so, many things can go wrong, and it is important to verify the WBE to know that it meets its indispensable characteristics while also keeping the costs low.

All barrier elements placed in a well have to be verified. As the WBE is installed in the well, NORSOK D-010 recommends the following to be done to ensure the integrity of the installed WBE.

Of an installed WBE, its integrity shall:

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

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

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)

(NORSOK D-010 Rev.4, 2013)

4.4.1 Internal WBE

The main purpose for an internal WBE is to seal the well so that no fluid can escape from a reservoir section and further up the wellbore to the external environment. It is obvious that the cement plug needs to be tested to recognize it if does in fact possess sealing capabilities, and this can be done in either the direction of the flow or against it.

Prior to setting the plug, the cement slurry itself needs to be thoroughly tested and verified in a lab. This will ensure that the proper strength development under the given circumstances is established.

A basic way to ensure a successful cement job will first and foremost be an evaluation of the job's success. The personnel will check for any cement returns topside and compare it to volumes pumped and hole size, and can in this way give an approximate answer to the placement and height of the plug.

4.4.1.1 Inflow Test

The inflow test is designed to test the plug's ability to withstand a pressure differential. The general idea behind it is to reduce the hydrostatic head above the cement plug, which can be done by bleeding of the shut in pressure of the well or by circulating it to a lighter fluid. In any case, it will provide a differential pressure on the top/bottom of the plug, and pressure gauges are used to monitor a potential pressure increase in case the plug should turn out to be faulty (leak). If there is no pressure increase, then the plug is sealing the wellbore under the current conditions, and therefore no fluids from the reservoir can escape.

Inflow tests normally last for a minimum of 30 minutes with a stable pressure reading, according to NORSOK D-010. This may vary depending on volumes, high compressibility fluids or temperature effects (NORSOK D-010 Rev.4, 2013).

The technique is applied as a part of several operations, amongst them well testing, deep water riser disconnect, drilling out of casing below a permeable high pressure (HP) zone, etc. (NORSOK D-010 Rev.4, 2013).

4.4.1.2 Pressure Test

The pressure test is an important technique of testing WBEs, and is fundamentally the opposite of the inflow test. The test is normally applied in the direction of flow towards the external environment, although it is possible to perform it in the opposite way if it is physically possible and does not to add an additional risk.

Under normal practice, the well will be pressured up to a certain point for a given period of time while pressure gauges is carefully monitored. As with the inflow test, changes in pressure during this time will determine if there are no leaks.

The normal approved leak rate is zero, and it will be specified in the EAC's if this is not the case. Changes in volume, temperature, air entrapment and media compressibility may occur, and it is important to include this in the acceptance criteria of the plug.

In NORSOK D-010 there are multiple levels of this test to perform. A "low pressure" test includes 15-20 bars for a minimum of five minutes of stable readings prior to any high pressure testing. The high-pressure test is set to be equal to or higher than the maximum differential pressure that the WBE may encounter in its lifetime. The readings shall stay stable for 10 minutes for this to be approved (NORSOK D-010 Rev.4, 2013).

4.4.1.3 Tag TOC & Load Test

After a completed placement operation for a cement plug, it is of interest to accurately measure the position of the plug in the well. A simple way of achieving this is to tag the top of cement (TOC), which will be performed by using the drillstring or toolstring to tag the cement plug and then measure the length of the string from the rig.

In cases where it is a risk to perform tests by altering the pressure of the wellbore, a load test can be used. This is helpful in cases such as a plug set in an open hole, where a large pressure increase could potentially fracture the formation. The load test is similar to the tagging; the string is lowered onto the plug and additional weight is applied to it. As the weight on bit (WOB) increase, the position of the bit will stay constant it the plug has set and become solid.

If the bit changes position with added weight, the cement plug is of bad quality and will not be approved. As a result of contamination during the cement placement, the uppermost and lowermost part of the plug can be of poor quality and is often drilled off after the plug is set. This is of course taken into account during the test.

4.4.2 External WBE

As it is very difficult to perform physical tests such as pressure or tagging on the WBE that hides behind the casing, alternative methods are used for these WBEs. It is important to acquire knowledge about the height and quality of the seal, including degree of bonding, presence of pockets, cracks and channels, and to distinguish between the WBEs material and the formation or settled barite from mud.

Volumetric calculations from the original cement job are an easy but crude way of evaluating an annular WBE. This is done by measuring the amount of cement return to surface, compared to volume pumped and volume of space between the formation and the outside of the casing. Although it may give a pointer to whether or not the operation was successful, in addition to an estimated TOC, it does not give any information on the sealing capability of the WBE. In addition, uncertainty about the actual path of the walls in the wellbore can create a false volume calculation and thereby wrongfully estimation of the TOC.

Logging can be used as a better option for the evaluation of annular cement. NORSOK D-010 requires a logging of casing cement before P&A, and that the internal WBE shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE (NORSOK D-010 Rev.4, 2013).

It is generally looked for two parameters in these cases: the bond and the integrity. The main tools used are the Cement Bond Log (CBL) and the Ultra Sonic Image Tools (USIT).

4.4.2.1 Cement Bond Log

The CBL is very useful to find two kinds of bonds: the cement-to-pipe bond and the cement-to-formation bond. The concept behind a conventional CBL tool is to transmit an acoustic signal in all directions, which travels along various paths like the borehole fluid, pipe, cement and formation, and back to a set of receivers. The interpretation of the signals will then give the answer that is sought, with the amplitude of the curve giving the quality of pipe-to-cement bond and the waveform is used to determine both pipe-to-cement and the cement-to-formation bond (Shook, Halliburton, & Tony Lewis, 2008).

As visual examples of the concept, figure 18 and figure 19 represents good cement and no cement, respectively, in a cased-hole completion.

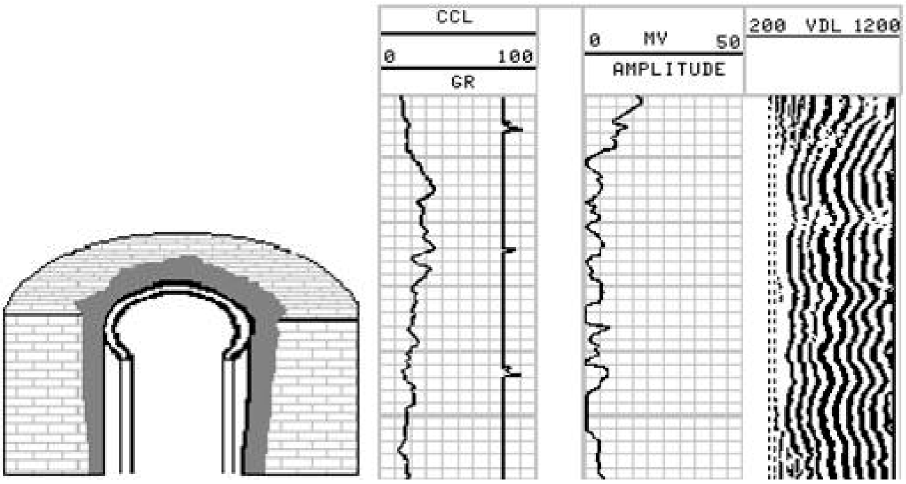


Figure 18: CBL Good Cement (Bridge7.com, 2011)

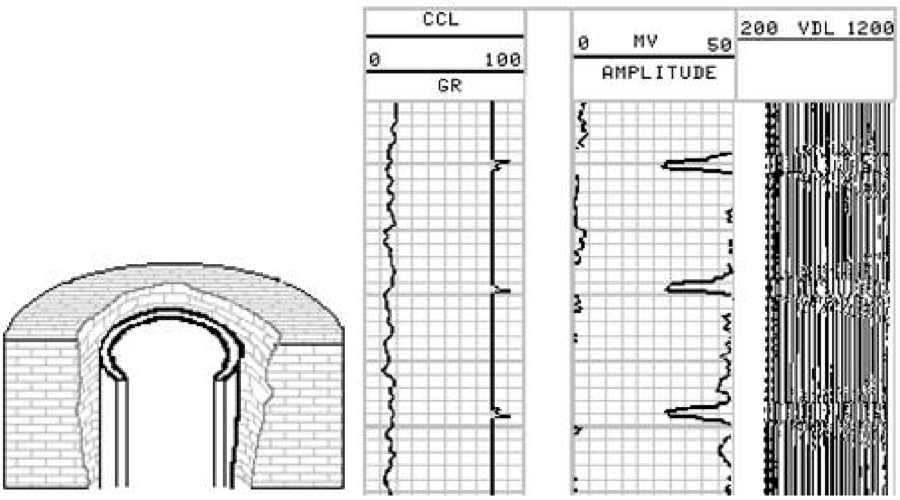


Figure 19: CBL No Cement (Bridge7.com, 2011)

The CBL is a valuable tool and is abundantly used, but nevertheless there are problems. The main ones have been recognized as tool centring, gating, and the microannulus effect. These must be dealt with to obtain proper quality on the log and so the interpretation.

4.4.2.2 Ultra Sonic Logging Tool

As a contrast to the CBL, this tool is built up with an ultrasonic source and receiver mounted together to form a transducer. Information about casing radius, thickness and impedance of the material behind it is possible to measure.
A single rotating transducer is used to produce an ultrasonic signal that is in turn evaluated with respect to the two way travel time, frequency of the signal and the die down response. The evaluation will reveal the condition of the casing, and the cement sheath in the annular space adjacent to the casing (Shook, Halliburton, & Tony Lewis, 2008).

An example of the resulting product can be seen in figure 20, where the orange/brown colour gives a clear indication of cement of good quality along with the location of TOC.

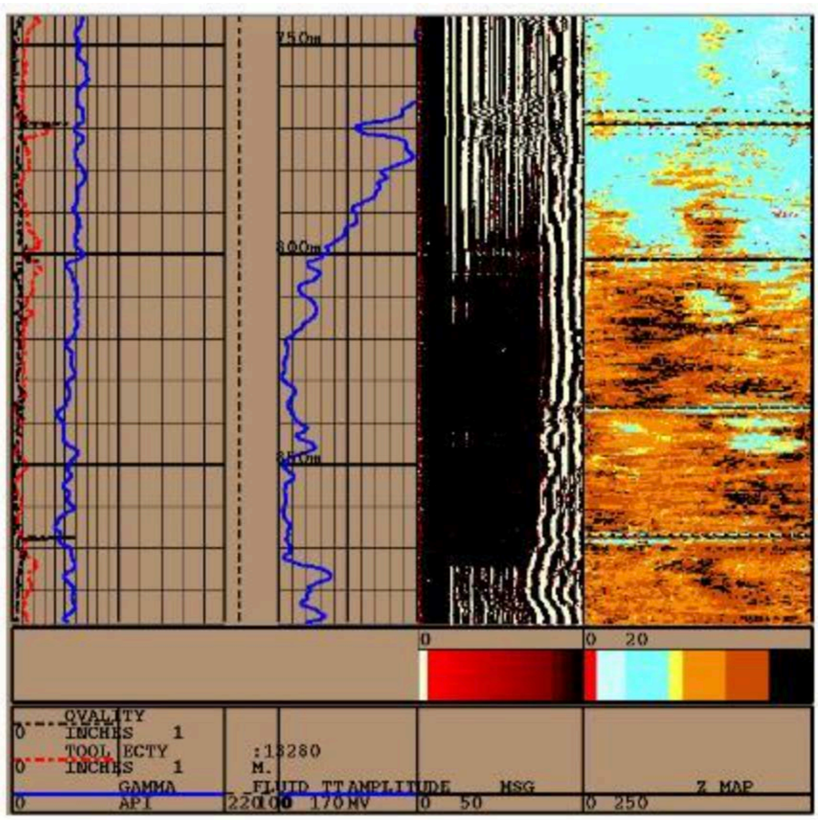


Figure 20: USIT Example (Bridge7.com, 2011)

5 Plugging Material Alternatives

Although Portland cement are overrepresented as the primary material used for P&A operations, it does not preclude the use of other materials for the same purpose. In fact, rev. 4 of NORSOK D-010 greatly mentions “material” instead of “cement” when referring to a permanent plug. As a result, any material with the previously discussed characteristics for a permanent barrier may be applied.

Cement does indeed fulfil these characteristics, along with being relatively inexpensive which are the main reasons for its popularity. The last point is an important one, as it is rare to change a functioning material for a more expensive one. There are, of course, some flaws with using cement – as stated in table 4. The table also lists the seven main groups of plugging materials that we have today along with their advantages and concerns.

Table 4: Advantages and concerns on material alternatives (Khalifeh, Saasen, Hodne, & Vrålstad, 2013)

Material Type	Advantages	Concerns
Cements	Low fluid loss, Adjustable slurry parameters, High compressive strength.	Corrosive environments, HPHT, Tectonic stresses, Low tensile strength, Low permeable, Possible gas influx*
Cement Derivatives	Low fluid loss, Adjustable slurry parameters, High compressive strength, Withstands corrosive environments and HPHT.	Hostile in some cases, Possible gas influx, Tectonic stresses.
Formation	No shrinkage, Rigless operation, Low permeability.	---
Grouts (non-setting)	Bingham plastic behaviour, Tight barrier, Adjustable slurry parameters, Self-healing, Pumpable, Un-affected by any downhole chemicals.	Possible gas influx, Unstable at HT, Requires foundation, Low shear strength, Pollution, Filter loss circulation
Thermosetting Materials	High tensile strength, Pumpable through narrow channels, Increased compressive strength, Low permeability.	Unstable at HT, Reactive to crude oil, Low vertical shrinkage
Gels	Can be reformed to fit well collapse and movement	Sensitive to salt, Sensitive to metal ions
Metals (Bismuth-based Materials)	Impermeable, Corrosive resistance, Expandable, High tensile strength, Recoverable, Non-toxic. Wireline cable installation.	Unstable at HT, Additives unavailable, Poor metal-formation bonding, Creep in tension, Un-pumpable.

*An intrusion of gas into the cementations sealant, which increases the permeability

As a part of the constant development of the petroleum industry, new types of WBEs are constantly being developed. Typical examples are new isolation materials such as Sandaband and Thermaset, in addition to the use of formation.

5.1 Sandaband – Sand for Abandonment

Sandaband is a smart alternative to cement. It is a product consisting of 70-80% solids (quartz, crushed rock, and micro silica) mixed with 20-30% water and fluidizing additives (Vignes, 2011). Despite this very high content of solids, it is still supposed to be pumpable.

While Sandaband shares some characteristics with normal cement, what makes it unique is that it is non-consolidating, non-segregating, non-shrinking and non-fracturing (Sandaband.no, 2015). This, of course, means that the placed plug will not set like cement and that it will not shrink. Electronic forces between the water molecules hold it together and the surface of the smallest micro-silica grains hinder flow in the pore space (Vignes, 2011).
As a force is applied, the material floats, shear forces are reduced below yield strength and the plug reshapes instead of fracturing. Another advantage of it not settling is that it can be circulated out of the wellbore again, for temporary abandonment purposes.

The resulting plug is gas-tight, and because its sealing properties are decided by the solids particle size distribution along with the bound water, it is thermodynamically stable. The tightly packed particles along with absence of free water means that the entire plug is homogeneous, and no internal redistribution may occur (Saasen, et al., 2011). Given that it is unconsolidated sand, it has to be placed on a foundation and not on a liquid, as the density difference of the latter would cause it to fall through. A visual example is given in figure 21.

Figure 21: Sandaband sample (Grannes, 2011)

5.2 Thermaset

An alternative material that does set is Thermaset, which is a polymer-based resin. When it sets it will harden into a strong and yet flexible solid, able to withstand thermo-cyclic expansion and contraction without cracking. It develops a good bonding to steel, and are compatible with most fluids and cements while being extremely tolerable to contamination, being able to tolerate 50 % of contamination while still being able to achieve a hard-set competency (WellCem AS, 2015).
It is a solid-free, low viscosity product, and is therefore capable of penetrating deep into permeable formations and narrow channels and so to seal any undesired flow into or out of the wellbore. A Thermaset application is illustrated in figure 22.

Figure 22: Thermaset in the wellbore (WellCem AS, 2015)

It is a highly adjustable product, and can be set to a specific gravity (SP) range from 0,7 to 2,5 SG and a viscosity range of 10 – 2000 centipoise (CP).
Thermaset is designed to set when it is exposed to a specific temperature over a given time interval. This means that the set time can actually be controlled to range from a few minutes to several hours, illustrated in figure 23 where the curing graph of Thermaset is illustrated. Ultimately, will reduce the wait on cement (WOC) time and allow an operator to save money on the operation (WellCem AS, 2015).

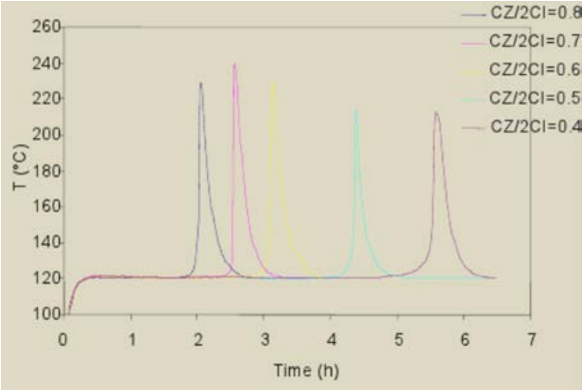


Figure 23: Thermaset curing (WellCem AS, 2015)

5.3 Shale Annular Barriers

Some formations have a natural tendency of slowly changing its shape plastically, and thus without fracturing. In a wellbore this will effectively decrease the diameter of the hole. If this happens too quickly it can cause serious problems, as the drillstring can be jammed in the wellbore or that the casing can be impossible to run. However, if it were to happen after the casing is run, it can be qualified as an annular barrier behind the casing – saving both operational time and expenses. Shale annular barriers cannot be predicted, and so the original P&A plan will include conventional barrier material to be used as annular barriers. However, a collapsed formation that is proven in place and subsequently qualified is a preferred situation on any well.

From the industry's point of view, the requirements in such a situation is:

"*If the formation has been displaced onto the outside of the casing in a uniform manner around the circumference and over a sufficient interval along the casing, then this formation could provide an annular barrier to reservoir fluid. In order to provide an annular barrier the displacement formation must have certain physical properties as sufficient rock strength and extremely low permeability to fluids.*"

(Vignes, 2011)

For the interested reader, table 15.51 and 15.52 in NORSOK D-010 rev.4 contains extensive acceptance criteria's for such a WBE. Important to note from these are the following:

The position and length of the element must be verified by two individual bond logs, which also determine the ability to seal. The minimum length of the plug must be 50 m MD, with 360 degrees of qualified bonding. The minimum formation stress at the base of this element must be sufficient to withstand the maximum pressure that could be applied, and the entire element must be able to withstand the maximum differential pressure. The latter is verified by applying a differential pressure across the interval, while the formation integrity is verified by a leak off test (LOT) at the base of the interval (NORSOK D-010 Rev.4, 2013).

6 P&A of Petroleum Wells

As a well reaches the end of its productive lifetime, it is time to permanently abandon it. The goal is subsequently to secure the well in an eternal perspective so that no hydrocarbons can escape to the environment, and to ensure that the site itself bears no evidence of the well's existence.

Specifically, NORSOK D-010 states:

"For permanent abandonment wells, the wellhead and the following casings shall be removed such that no parts of the well ever will protrude the seabed.
Required cutting depth below seabed should be considered in each case, and be based on prevailing local conditions such as soil, seabed scouring, seabed current erosion, etc. The cutting depth should be 5 m below seabed.
No Other obstructions related to the drilling and well activities shall be left behind on the sea floor"

(NORSOK D-010 Rev. 3, 2004)

Given that the well is plugged on an eternal perspective, it is vital to do it right the first time around. The well can re-pressurize, and a degraded barrier can eventually cause leaks. A study in the *Proceedings of the National Academy of Sciences* showed that many of the 300 000 – 500 000 abandoned wells in Pennsylvania might be leaking significant quantities of the powerful greenhouse gas methane. Methane is acknowledged to be 86 times as bad for the climate on a 20-year time scale as CO_2. A rough calculation showed that the abandoned wells in Pennsylvania may have contributed to as much as 4-7% of the total man-made methane emissions in 2010 (Kang, et al., 2014).

6.1 Required Information

As there are an exceptionally large number of different well designs currently in practise, it is very important to gather as much information as possible on the well that is being plugged. For wells being drilled today it is an obligation to plan for P&A before it is drilled. For much older wells, the gathering of viable intelligence can be difficult to find due to storage transfers and subsequent losses.

Amongst all information that may be available, the most important for a P&A operation is the general condition of the well, what type of well it is, the status of the cement, number of potential inflows etc.

NORSOK D-010 requests that the design basis should include:

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.

(NORSOK D-010 Rev.4, 2013)

6.2 P&A Phases

The entire P&A operation can be divided into different stages, and Oil & Gas UK defines the operation using three different phases. This means that it can be specified how complex each part of the operation is, and so to choose the best practice for that specific part. The aim is to be time and cost efficient. These phases are:

Phase 1 – reservoir abandonment

Primary and secondary permanent barriers set to isolate all reservoir producing or injecting zones. The tubing may be left in place, party or fully retrieved. Complete when the reservoir is fully isolated from the wellbore.

Phase 2 – Intermediate Abandonment

Includes: Isolating lines, milling and retrieving casing, and setting barriers to intermediate hydrocarbon or water-bearing permeable zones and potentially installing near-surface cement. The tubing may be partly retrieved, if not done in phase 1. Complete when no further plugging is required.

Phase 3 – Wellhead and Conductor removal

(Oil & Gas UK, 2012)

6.3 P&A Operational Sequence

As mentioned, there is a large variation of different designs on petroleum wells today. Because of this variation and to some respect, different practises, it is hard to develop a generic recipe on how to P&A a petroleum well. Nevertheless, there are many things that are very important and therefor repeat in many cases. For the reader new to P&A, figure 24 shows an example of a petroleum well and a following description of the main steps that can be utilized to perform a P&A operation on it.

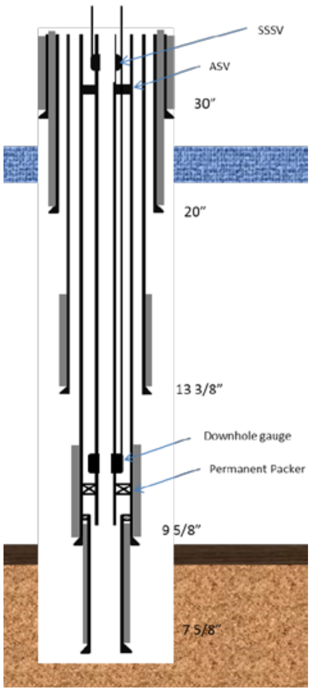


Figure 24: Example Well (Kalifeh, 2014)

Planning phase

As previously discussed, an operation starts with an extensive research phase in search for the required information. The degree of difficulty of this task can vary excessively, with some data easily accessible and other in poor and out-dated databases. A wireline (WL) survey will be run as a part of this operation to check the access to the downhole and to survey the quality of the tubing.

To streamline the operation, it is determined the complexity of the operation on all phases, and appropriate rigs and tools are suggested. This is further discussed in section 6.4. The planning phase is to some extent the most important part of the operation, because a good preparation will be likely to lead to a successful operation.

Logistics

Once all planning and schematics is completed and approved, the logistics part will commence. This involves the rig/vessel in question skidding into place, have appropriate personnel available and all equipment that will be utilized accounted for and properly tested. Once the operation has started, the idea is that it will run smoothly with no or very few unforeseen halts. Please remark that the rigs and equipment may change during the operation, but for the sake of simplicity in this example, it will not be mentioned further.

Kill and secure the well

Before the operation commence, the well needs to be killed. To kill a well is an expression for the discontinuing of flow from the well, or having the ability to flow into the wellbore. Often the method is to circulate a heavy fluid column into the wellbore, making it overbalanced (hydrostatic head is greater than the formation pressure) and eliminate need for pressure control equipment at the surface. In this case it is important not to exceed the pressure rating for the wellhead (WH), tubing or casing – as this can cause them to burst.

Another way of achieving this is called bullheading. Bullheading includes to forcefully pump a fluid into the wellbore to overcome the formation pressure, while still not fracture the formation. As this pressure is exceeded, the formation fluid in the wellbore is pressed into the formation, and is replaced in the wellbore with a sufficient density to contain the reservoir pressure once the circulation is complete.

For the example presented here, the assumption is that the primary barrier is not to be set at TD but at a higher position in the wellbore. For such a case, a mechanical plug (a bridge plug) is set in the tail pipe and then pressure tested. This will first and foremost create a temporary barrier against the formation pressure – and later a foundation for the primary barrier to be set on.

Check A-annulus

The next step is to check the pressure in the A-annulus, and then to bleed it off. The A-annulus is represented by the space between the production tubing and the 9 5/8" casing. As the pressure is bled off, it is looked for a sustained pressure in the A-annulus. Any increase in pressure is a sign of a leak, and creates an integrity issue as the tubing is removed.

Cut tubing

As discussed, a permanent barrier is not approved without sealing cement on the outside of the pipe itself, and this alone is reason enough that the tubing needs to be pulled.
The tubing is cut somewhere between the downhole gauge and the permanent packer, as it is stated in NORSOK D-010 that downhole equipment can cause loss of well integrity (NORSOK D-010 Rev.4, 2013). This includes control lines and cables, which can create leak paths and shall not be a part of a permanent barrier element.

XMT and BOP

The XMT is nippled down (N/D) and the blowout preventer (BOP) is nippled up (N/U). A BOP is used to achieve well control during the rest of the operation. The BOP stack is in essence a series of valves designed to regain control of the reservoir in any situation. These are known as pipe rams, annular and shear rams that are able to seal the wellbore and t cut the drillpipe or tubing. By using this in a P&A operation means that retrieval of the tubing and hanger is possible.
An example of a BOP stack can be seen in figure 25.

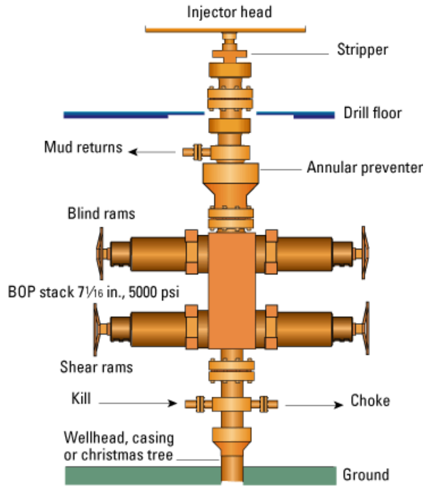


Figure 25: BOP Example (Schlumberger Limited, 2015)

Retrieve ASV

The annulus safety valve (ASV) is primarily used with gas lift completions. It is basically a packer with a small opening. The opening is operated from the surface, and is a fail-safe close solution for annular flow (Petroleum Safety Authority Norway, 2015).

Retrieve tubing and control lines

To pull the tubing and upper completion is heavy lift operation and will typically require a rig for the proper capacity.

Log cement

As the tubing is removed the 9 5/8” casing is revealed, and a logging operation is performed. Using the previously discussed CBL and USIT logs, the cement and formation behind the casing is logged and interpreted. If the cumulative interval of external seal is not found and approved, the casing needs to be cut and pulled or milled. This latter is an operation that will be extensively discussed in chapter 7.

Establish well barriers

As the sections are verified, the plugs can be set. The foundation for the primary barrier is the already installed bridge plug in the tailpipe. For the secondary and open hole to surface barriers, different solutions can be utilized. Although a mechanical plug is often preferred, a placed pill of high viscosity or a cement support tool can be applied.

As each barrier element is set, it is verified with both pressure tests and tagging.

Cut and retrieve wellhead

The final phase for permanent abandonment is to remove the wellhead, conductor and surface casing. As mentioned, NORSOK recommends it to be cut five meters below seabed. Knives typically do the cutting, although both explosives and abrasive jet cutting can be utilized. As the cutting is done the site is covered with soil or available cuttings, and the neighbouring environment is restored to its original state.

6.4 Rig Capacity & Cost

Traditionally, a big drilling rig has been used as the primary vessel for a P&A operation. It is an easy solution, in that it can handle each phase of the operation on a complex level. As a P&A operation normally requires the tubing to be pulled along with the casing, or at least parts of it, it is required a vessel with a substantial lifting power.

However, using rigs does present an issue: it's expensive. For a relatively simple part of the P&A, a rig represents a big day rate compared to a smaller vessel, plus the added opportunity cost of having the rig do an easy operation while it could be off doing something more profitable. The issue is illustrated in figure 26, where the intervention cost using a rig is compared to alternative vessels.

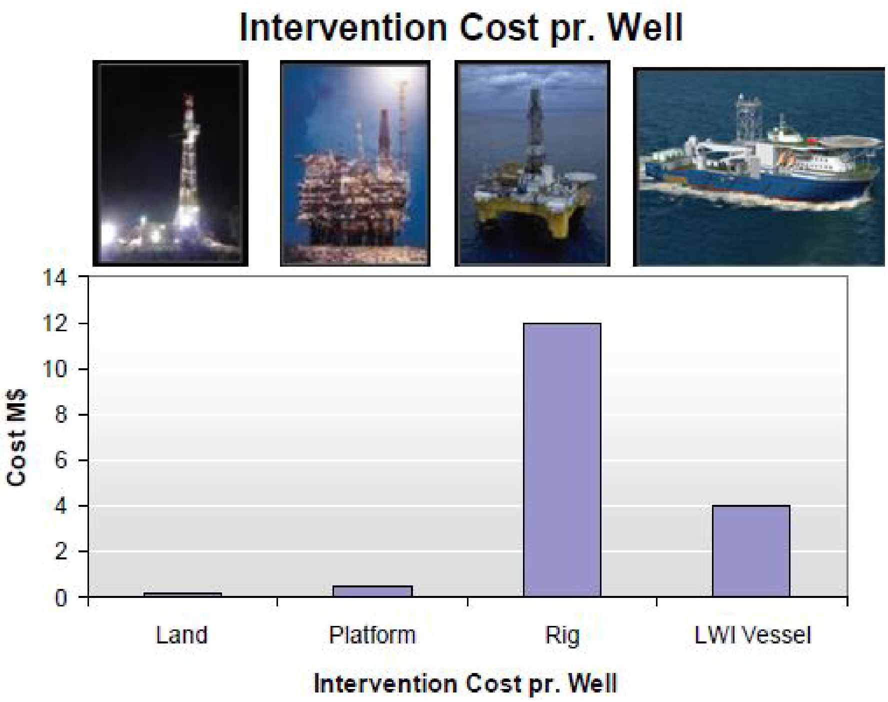


Figure 26: Cost of intervention per well using different vessels (Fjærtoft & Sønstabø, 2011)

The explosive growth that is expected from the P&A market may lead to a substantial challenge with regards to the availability of rigs. An internal report in Statoil from 2011 shows that from 2012-2019, an average of one rig per year will be needed for P&A operations (Eshraghi, 2013). As figure 27 illustrates, there is a substantial growth in expected P&A activity from 2020-2024, where three to four mobile offshore drilling units (MOUs) and an additional three to four fixed rigs will be needed for P&A each year. Figure 27 also gives an estimated nominal cost for the expected growth. It can be perceived that the cost per year increase from a combined 15 billion NOK in 2015-2019, to just shy of 60 billion NOK in the years 2020-2024.

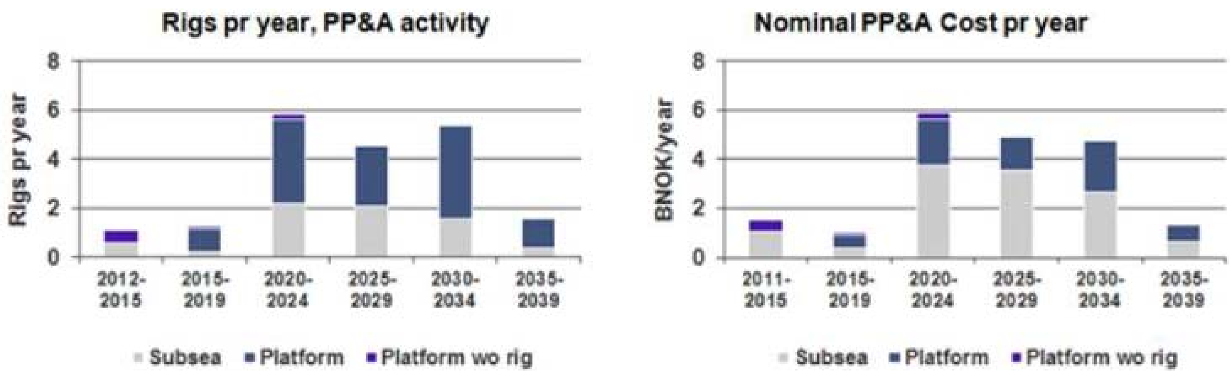


Figure 27: Time & Cost estimation for Statoil P&A (Eshraghi, 2013)

The expected nominal cost are definitely leaving some operator-companies uneasy, but given that 78% of the total cost of a P&A operation comes from the Norwegian government, it is in everyone's best interest to minimize these costs.

By transferring operations like P&A from rigs to dedicated vessels, the costs of the operations will decrease while the drilling production will increase by leaving the rigs to perform their core functions (Saasen, Fjelde, Vrålstad, Raksagati, & Moeinikia, 2013).

As fixed platform wells are currently seeking methods of transferring P&A to smaller vessels, the goal for subsea wells is to either minimize or eliminate the use of semi-submersibles. The use of light well intervention vessels (LWIs) is becoming more common, and a future goal is to be able to use these for the entire P&A operation. It is estimated that the transfer of P&A on rigs to LWIs on approximately 1000 subsea wells on the NCS has the potential of saving 150 billion NOK (Eshraghi, 2013). Technology gaps currently being worked on to achieve this includes:

- Pulling tubing and/or casing without the use of a riser
- Placing a cement plug from the LWI without the use of a riser
- General P&A challenges

6.5 Cost Estimation for P&A

A proper cost estimate is a vital phase of any planning in the petroleum industry. Today, a plan for any new well on the NCS includes a plan for the P&A phase, and therefore a cost estimation is accounted for in an early phase of the well's lifetime.

The number of variables combined with the fact that the companies withhold information about economics due to confidentiality, makes it hard for this thesis to provide the reader with accurate costs. As a result, the primary saving that this thesis will target is the time consumption – as the familiar saying goes: time equals money.

Nevertheless, an anonymous company that has been providing raw data to this thesis discloses that they use the daily rate of four million NOK to calculate costs when they are not going through a comprehensive calculation. This is a burn rate that includes the rig rate as well as an average loss (equipment, etc.), and it is also cross-referenced with the numbers used by Malin Torsæter from SINTEF Petroleum in Riggkonferansen 2015 (Malin Torsæter, 2015). As a result, the cost estimation for this thesis will be built upon the time consumption multiplied with this rate, to provide the reader with a rough estimation of the impact.

UK Oil & Gas are ahead of NORSOK on this bit, and has already recognized the impact on economics that P&A represent. In this sense it has published a guideline called "Guide on Well Abandonment Cost Estimation" (Oil & Gas UK, 2011). Included in the guideline is the expected time consumption of each of the phases and with the different types of vessels for platform and subsea wells. These are included in table 5 and table 6, to give the reader an idea of the time consumption that is expected from the different scenarios of P&A in the UK guidelines.

Table 5: UK Oil&Gas P&A duration for platform wells (Oil & Gas UK, 2011)

Platform Well (Days)			**Abandonment Complexity**				
			Type 0 No work required	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig-based	**Type 4** Complex Rig-based
Phase	**1**	Reservoir Abandonment	0	3	5	3	7
	2	Intermediate abandonment	0	3	6	5	10
	3	Wellhead Conductor Removal	0	2	4	2	8

Table 6: UK Oil&Gas P&A duration for subsea wells (Oil & Gas UK, 2011)

Subsea Well (Days)			Abandonment Complexity				
			Type 0 No work required	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig-based	**Type 4** Complex Rig-based
Phase	**1**	Reservoir Abandonment	0	3	5	2	12
	2	Intermediate abandonment	0	3	6	6	10
	3	Wellhead Conductor Removal	0	1	3	2	8

6.5.1 The Approach

A simple method that is used for cost estimation is the deterministic approach. This is a method that traditionally has been used in the industry, and it has the advantage in that the results can be transferred easily. In this approach, the operation are broken down into sub-operations and given a single point. These points are most often determined based on historical data (benchmarking) or expert judgement. However, it has a constraint in the form of giving biased results and that it cannot capture the full range of the outcomes.

As a result, the probabilistic approach has recently been recognized as the preferred technique. The technique can yield non-biased results and it allows for uncertainty to be implemented, covering the correct range of possible outcomes. It will exert a full range of possibilities with occurrence of probability associated with each outcome in form of a distribution curve or histogram (Moeinikia, Fjelde, Saasen, & Vrålstad, 2014). For example, the outcomes from the probabilistic tool of Monte Carlo simulations yields the results presented as the percentiles P10, P50 and P90. P10 means that there is a 10% chance that the cost or time will fall on that value or below it, while P90 means there is a 90% chance that it will fall on that value or below.

The way Statoil breaks down the different aspects of costs in an operation is presented in figure 28. As perceived, the expected cost is broken down into two sub-categories; net operating cost and the contingency cost.

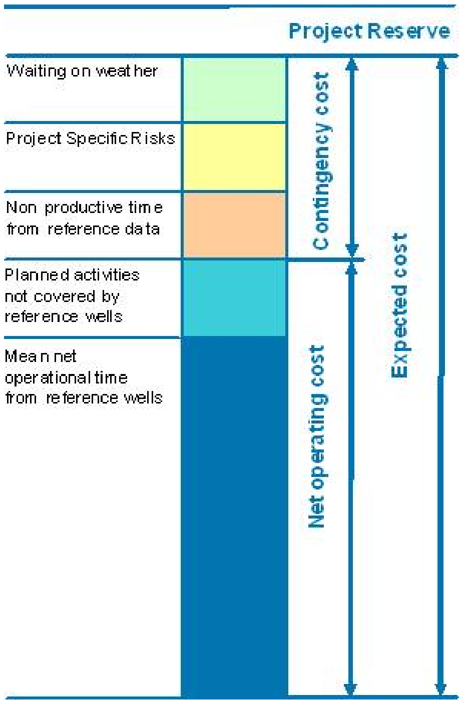


Figure 28: Expected costs broken down (Birkeland, 2011)

The net operating costs is predominantly based on the net operating time, and represents the costs of an operation that goes 100% according to plan (rig rates, service rates etc.). The wild card of the expected cost is the contingency cost, which are hard to quantify but needs to be accounted for. As given by figure 28, there are some non-productive time that are estimated from wells with similar characteristics. In addition, costs that are specific to the well in question can be loosely quantified using a risk analysis, meaning that known risks are determined and included based on the likelihood of them occurring and the cost it would implement if they did.

The final sub-category of the contingency cost is the added expense of having to wait for appropriate weather conditions either to continue or to start an operation, commonly referred to as "wait on weather" (WOW). Table 7 shows the experienced numbers from Statoil with regards to WOW, split up in different vessels/rigs and season of the year (Eshraghi, 2013). This is, because of the nature of the harsh conditions in the North Sea, perhaps the factor that is least in the hands of the operator.

Table 7: WOW Statistics, Statoil (Birkeland, 2011)

	Fixed	TLP	Semi	Jack-up
Winter	3,7%	9,8%	13,7%	2,7%
Summer	0,5%	1,1%	1,7%	1,6%
Average	2,2%	5,3%	7,3%	2,2%

7 Section Milling

In many cases it is impossible to place an approved, permanent plug over the desired interval. As previous discussed, the approved WBE needs to extend across the full cross section, and seal both in a vertical and a horizontal direction.
This is often a problem due to a stuck casing, a poor cement job behind the casing causing leaks or that the cement is missing all together and there is no way to access the last open hole section. In any case, the casing and poor cement needs to be removed and a proper barrier element needs to be set. To achieve this, a section milling operation has traditionally been the most common method. The goal of the section milling is to grind away a section of the casing along with the contamination behind it, and so to create a section of fresh formation where a barrier element can be set.

However, section milling is a costly operation with many possible contingencies, and as a result it is an operation that is only performed when absolutely necessary. The challenges with the technology along with the economic impact it brings will be discussed further throughout this chapter.

7.1 The Operation

The milling operations as a whole is not limited to section milling alone, but may include such things as milling junk downhole or a small section of a pipe that has yielded under external pressure and is limiting passage. In any or all cases, the milling will include using a rotary tool to break away any unwanted solid material into fragments with the intention of permanent removal. For the intent of this thesis, section milling will be the primary focus.

In a section milling operation, a tool assembly like the example in figure 29 is lowered to the desired depth of the milling. The tool is run on a mix of normal drill pipes and drill collars to add weight, often with a jar attached if the mill were to get stuck. On the lower end, a coned mill called a taper mill is often attached. This has an integral carbide nozzle threaded in the bottom end, which allows positive fluid control to the section mill knives. It also creates a continuous flushing and cleaning action on the knives of the section mill, which prevents cuttings from balling around them and to cool the structure (Weatherford, 2014).

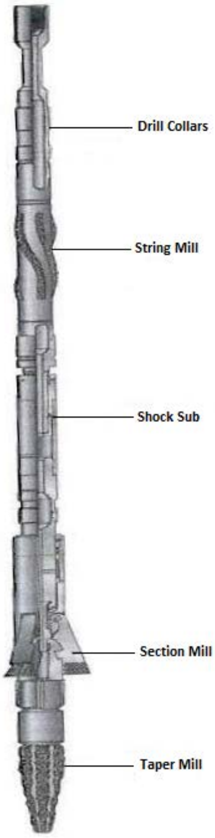


Figure 29: Section mill assembly (DeGeare, Haughton, & McGurk, 2003)

Once at the desired depth, a pressure is applied to make a cone exert force on the knives (hydraulic), seen in figure 30. This effectively extends the knives themselves and makes it possible to mill. Applying a rotational force to the tool will then make a cut in the casing body, and once the cut is completely through it, the milling is commenced.

The milling will normally be done in a downward fashion, meaning that the weight applied from the drillstring is what pushes the milling tool down.

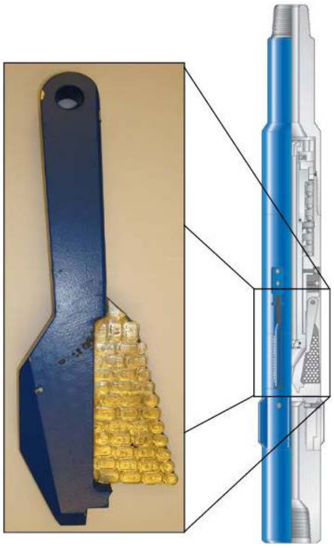


Figure 30: Zoomed cutter and section mill (Stowe & Ponder, 2011)

To give a broader picture of what this entangles, the following steps is taken from the procedural guideline provided by Weatherford:

1. Make up the tool string, and run in the hole to depth of the intended cut-out.
2. Rotate at 60 to 80 RPM for the cut-out.
3. Start the pumps, and build the pump strokes to the output (gallons or litres per minute) required to give the minimum pressure drop across the piston nozzle of the tool, depending on its size. After the cut-out, the pressure drops 200 to 500 PSI (1379 to 3447 kPa), depending on the tool size.
4. After the cut-out, rotate 10 to 15 min to clean the cut.
5. Apply weight, and increase the rotational speed to 150 to 350 SFPM. The most efficient milling weight is usually 2000 to 9000 lb. (907 to 4082 kg).
6. After the section is milled or when the knives are worn out, circulate until the hole is clean.
7. Stop circulation, and rotate for 5 to 10 min for the correct knife closure.
8. Pull the tool into the shoe, and trip out conventionally.

(Weatherford, 2014)

As the section milling is completed to the desired interval, the open hole is cleaned for as much debris, metal cuttings and mud as possible. The part with exposed formation is then under-reamed to enlarge the size of the hole and expose fresh formation, which makes it easier to achieve good bonding and ultimately a proper cement job. This is illustrated in figure 31. The proper execution of these operations will ensure a good section to place a plug.

Figure 31: Conventional under-reaming (HydraWell, 2015)

7.2 NORSOK & Milling

NORSOK D-010 rev. 4 includes a manual on how to plan the section milling operation from the logging of annular cement to the point where barriers are set. Specifically it lists when to use section milling, what actions to include and which length the intervals should be. It is presented in the form of a flowchart, and can be seen in figure 32.

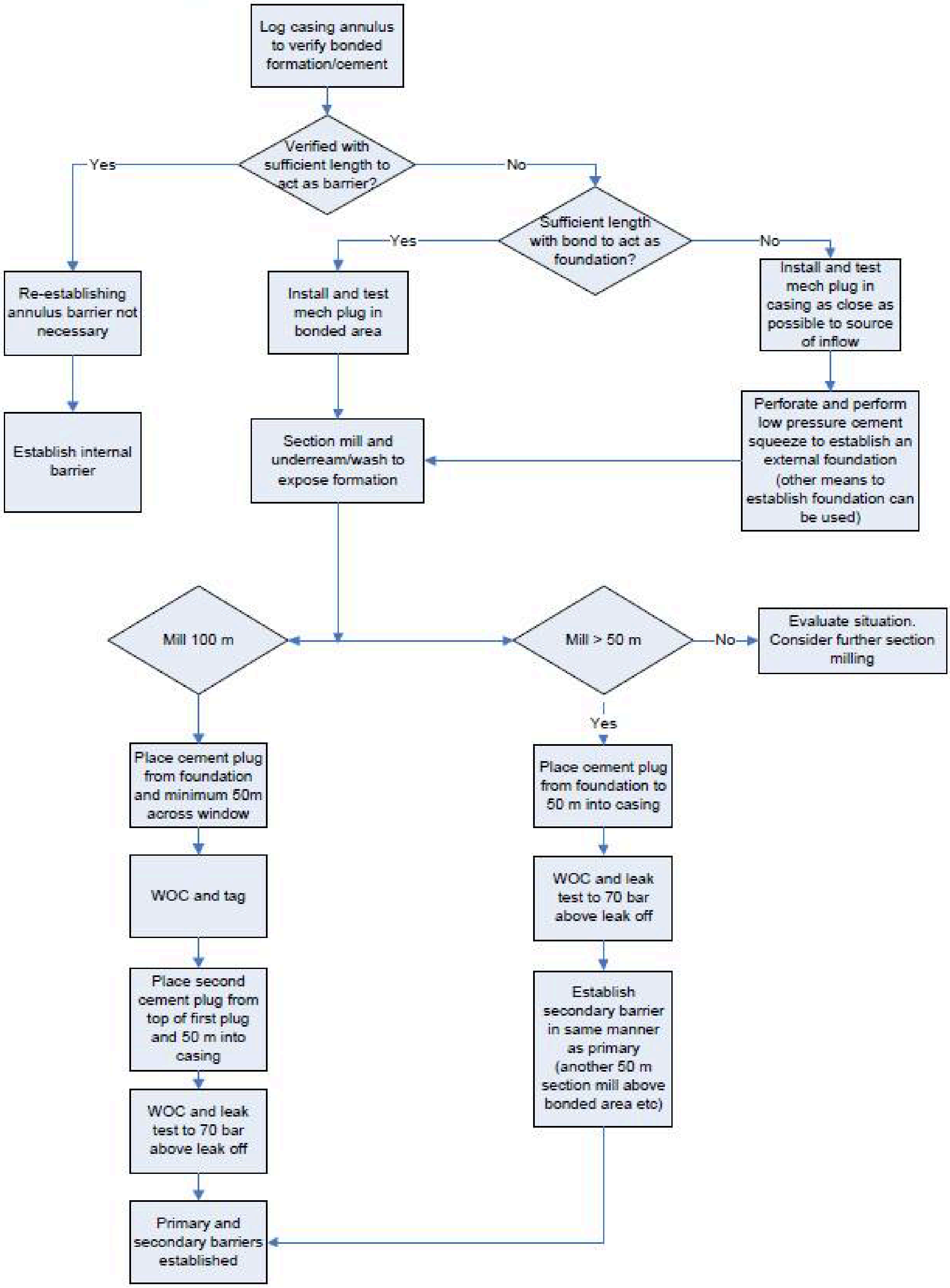


Figure 32: Section milling flowchart (NORSOK D-010 Rev.4, 2013)

The resulting schematic of the plugged well could look like something like the examples in figure 33. Here the example well on the right is compiled with a 100 m long milled section, and with two back-to-back cement plugs set. The examples on the left has twin 50 m long milled sections, with a barrier set in place on each. The configurations on each well may vary greatly and so affect the P&A operations, but the end product will have the same effect as the example below.

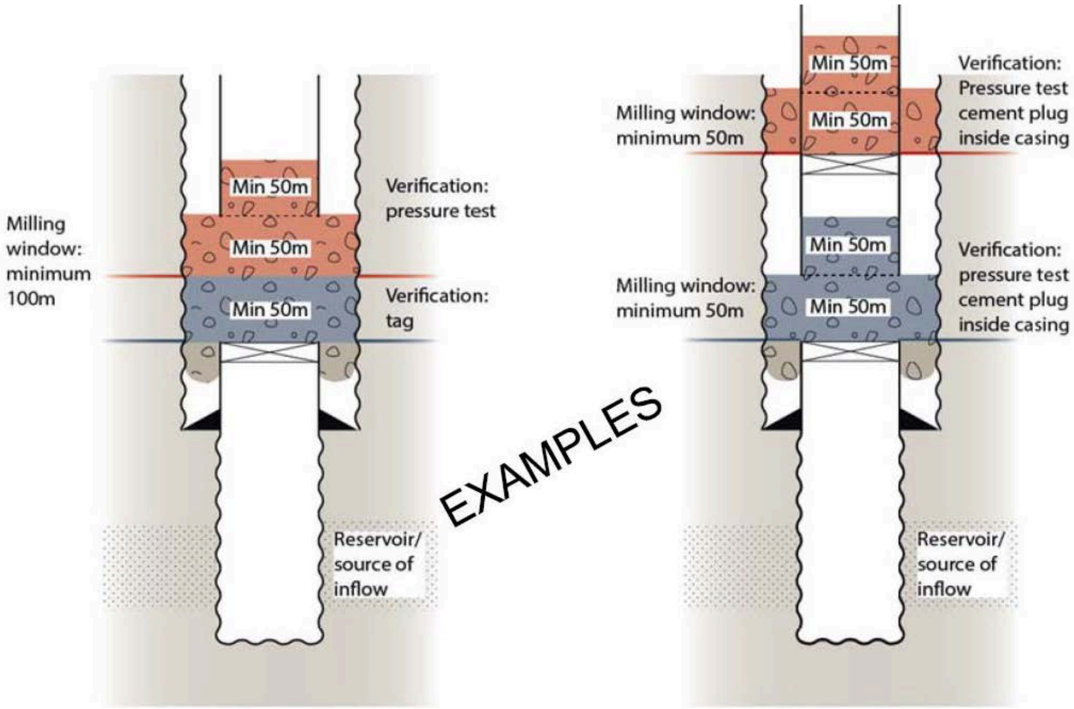


Figure 33: Section milling, NORSOK D-010 (NORSOK D-010 Rev.4, 2013)

7.3 The Challenges

As previously stated, the section milling operation is only performed when it is absolutely necessary. This comes as a result of the many contingencies that are encountered on an operation, and the damaging effect it can have on HSE, equipment and economics. The following is an investigation into what the main challenges of the technology and what affect it can have.

7.3.1 Time Consumption

Conventional section milling during P&A is, above all else, a time consuming operation. As it has been discussed, the implementation of NORSOK D-010 rev. 4 increased the average time of the P&A operation, but this is not the entire picture. The complexity of the operations, along with unforeseen and challenging incidents is to blame for a lot of time consumption, and offshore time is expensive. Lack of data on the oldest wells has traditionally been a challenge, and decisions have been made without proper knowledge. Conversations with the industry confirm that a lot of uncertainties in the operations, along with limited experience in P&A makes it difficult to claim an expected duration during planning of P&A, and so an operation can take everything from around 30 days to complete, with 60 days easily surpassed with the many contingencies that can occur.

With this at heart, this section will go into further detail to investigate what amount of time consumption the section milling actually represent, and what costs this brings with it.

Table 8 is from ConocoPhillips operations in 2008, where two of total eight water injection wells were plugged (Scanlon, Garfield, & Brobak, 2011). During the installation of the 9 5/8” casing of these wells there was encountered losses during the cementation, and so the intervals where the barriers two and three are typically placed is with un-cemented pipe which needs to be removed. The average of the two operations was 65 days, *not* including 31 days WOW. These wells went on to start an improvement campaign in collaboration with Baker Hughes, which will be further discussed with relations to cutters in section 7.3.3.

Table 8: Main operations for W-04 & W-02 (in days) (Scanlon, Garfield, & Brobak, 2011)

Well	Rig Mobilization	Install Barrier 1	N/U BOP and Pull Tubing	Install Barrier 2	Pull 9 5/8” Casing	Install Barrier 3	Install Barrier 4	Pull 20” and 13 5/8 Casing	Rig De-Mobilization	**Total**
W- 04	10.7	2.9	7.0	24.5	3.3	5.6	5.8	4.3	6.0	**70.1**
W- 02	0.4	5.5	4.9	25.8	15.2	1.7	1.1	3.1	-	**57.7**

Although the different aspects of the operations differs somewhat in the sense of time consumption, one thing stands out in both wells: the installation of barrier two. The installation of the secondary barrier in each well required deep section milling of the casing, and multiple section mill runs were necessary (Scanlon, Garfield, & Brobak, 2011).

Figure 34 gives a closer look at the time breakdown on setting barrier two in well W-04. As the figure suggests, the most challenging part of the operation was the 165 ft. of section milling and the following under-reaming of the open hole, representing 45% (281,25 hours) of the total time consumption. Although the under-reaming of the open hole is a separate operation to the section milling, it is a necessary operation after the milling and will therefore be included with regards to the millings time consumption and costs.

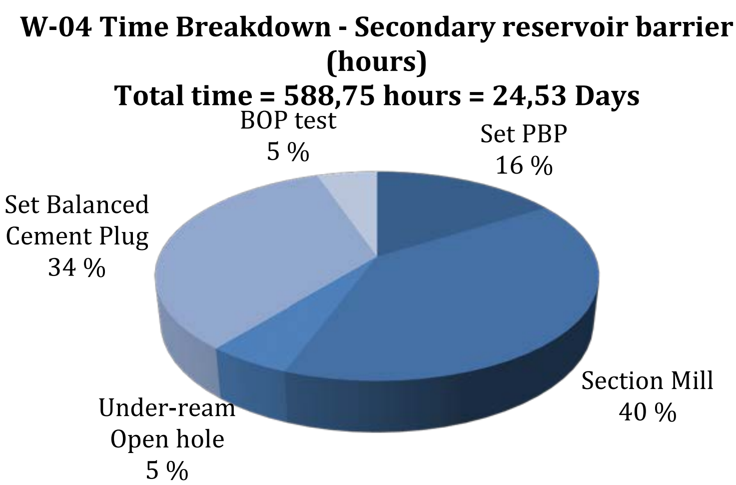


Figure 34: W-04 Time Breakdown (Scanlon, Garfield, & Brobak, 2011)

As it is claimed that contingencies during P&A can alter the timeline substantially, two further wells will be investigated. The diversification of source material will ensure a broader picture of the section millings time consumption.

A generous operator of the NCS has provided extensive material on two of their P&A operations to this thesis, but wants to remain anonymous for all intent and purposes. As a result, the following wells will only be referred to as “X-1” and X-2”. According to the operator in question, both wells provided are good examples on the impact of section milling.
Table 9 is a preliminary representation on the time and cost the installation of the barriers in each well racked up, along with a cost estimation based on the previously stated method.

Table 9: Time & Costs of P&A operations, X-1 & X-2

	X-1		**X-2**	
Operation	**Time (Hours)**	**Cost (Mill NOK)**	**Time (Hours)**	**Cost (Mill NOK)**
Install Primary Barrier	255,75	42,64	253,75	42,28
Section Mill 165 ft. + Under-ream	128,5 + 28,25	26,13	155,75 + 31,5	31,2
Install Secondary Barriers	365	60,84	310,25	51,72
Section Mill 330 ft. + Under-ream	153,75 + 28,75	25,64 + 4,79	148 + 70,75	24,68 + 11,79
Install Surface Plug	107,75	17,96	39,75	6,64
Total P&A operation	**910,25**	**151,72**	**754,25**	**125,72**
Total P&A operation	**37,9 days**	**---**	**31,4 days**	**---**

The following case 1 and case 2 is a further investigation into the P&A operations of each well, with a particular focus on what caused section milling and under-reaming to consume time.

7.3.1.1 Case 1: Well X-1

Case 1 features well X-1 on the NCS, which was plugged and abandoned in early 2010. Similarly to W-02 and W-04, the operation was performed via a jack-up platform and in a similar environment. As a result, the costs of these operations are assumed comparable.

The operation was intended to feature a total of 495 ft. of section milling, and the time breakdown of the operation is presented in figure 35. The breakdown is an illustration of the activities presented in appendix A.

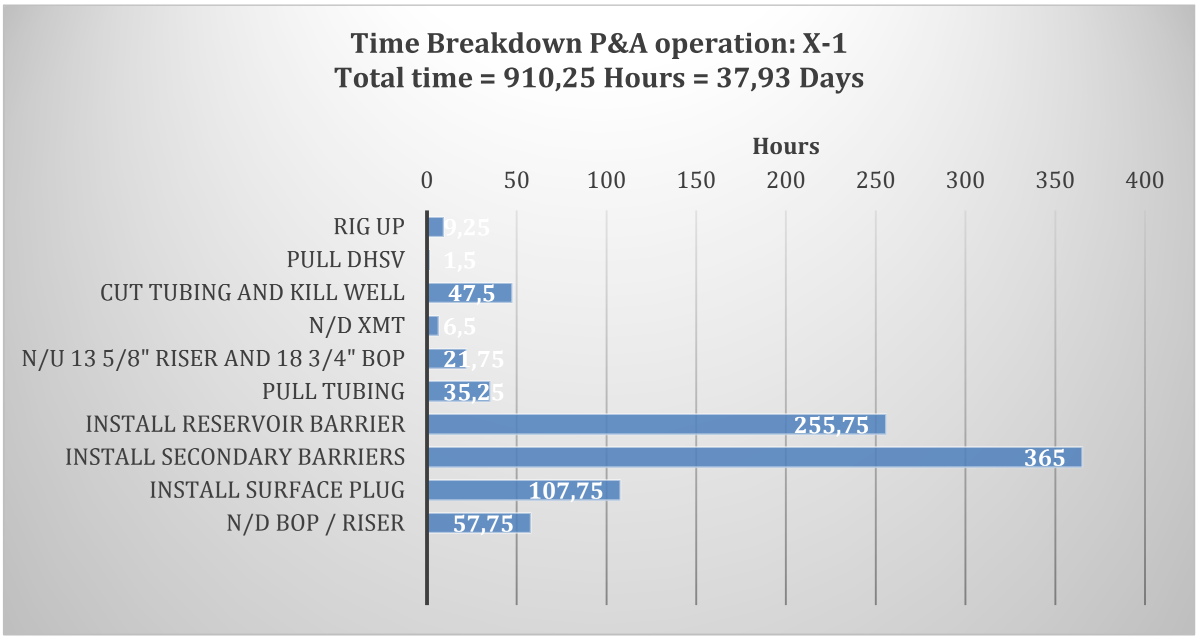


Figure 35: Time Breakdown, P&A X-1

As it can be perceived, the installation of the primary and secondary barriers takes up most of the time. Of the total time consumption of 38 days, these two stands for 25% and 36%, respectively – a total of 61%. This means that of an estimated 152 million NOK for the P&A operation, installation of the primary and secondary barriers represents around 104 million NOK of it.

Figure 36 gives a more detailed look into what part of the installation of the reservoir (primary) barrier that was most challenging.

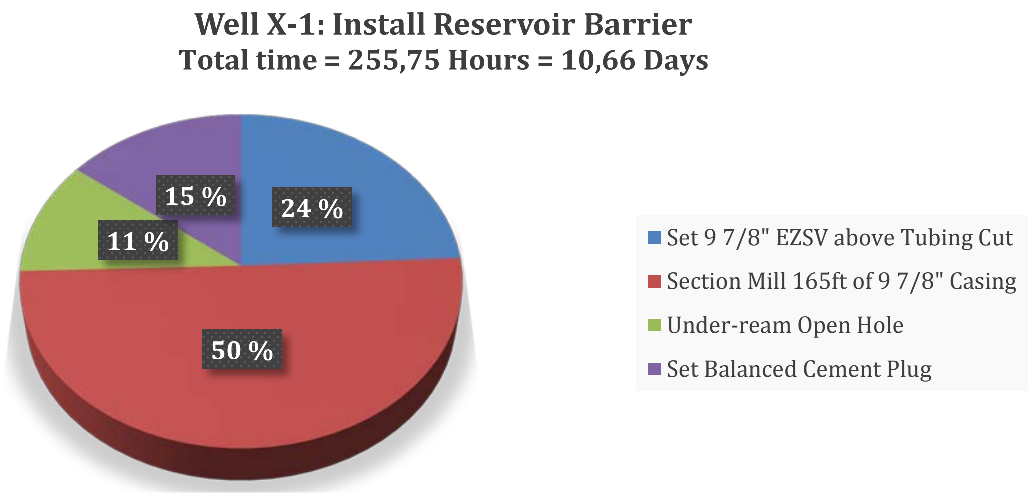


Figure 36: Detailed Reservoir Barrier, X-1

*EZSV = Drillable bridge plug

From figure 36 it is understood that the 165 ft. section milling of the 9 7/8" casing with subsequent under-reaming was responsible for 61% of the time it took to install the reservoir barrier. To compare, this is slightly more than W-04/W-02.
Further investigation into the official operations report from the rig reveals the problems that were encountered during the operation. This is a report that is chosen not to include into appendix, due to the large size of it along with extensive use of the company's name.

The report shows that shortly after milling parameters were established and the milling commenced, pack-off tendencies was observed. The problem was observed just six hours into the operation, and continued to cause problems throughout the entire milling operation.
Pack-off is often observed as an effect of poor swarf transport, and is further described in section 7.3.2. To avoid a stuck pipe, time is spent to pull up the pipe and try to circulate excessive swarf out of the well. Issues with pack-off are noted as a problem on nine separate occasions in the operations report on the reservoir barrier. On average, between 2-3 hours are spent each time fixing it, meaning that it is responsible for around 23 hours of the operations time consumption.

The final reported ROP for the milling itself was 6,2 ft./hr. for the milling of the primary barrier.

As the section milling was completed, the bottom was tagged and the crew continued to circulate fluid to remove swarf. While pulling slowly out, the crew observed the pressure as 2000 psi below normal, and that the BHA had stopped sending pulses. The drill string stalled and annulus packed of. The crew was able to free the pipe by applying an overpull of 100 000 lbs. and 18 000 pound-foot of torque. As it turned out, this was enough to free most of the BHA from the drillpipe, which in the report is not observed until the remains of the BHA is pulled out of the hole. As a result, an extensive fishing operation was commenced to collect the 71,08 ft. of missing BHA. The fishing operation took a total of 33 hours to complete, until the under-reamer assembly could be run. Besides some minor issues bypassing the dogleg of the well with the under-reamer assembly, this concludes the main issues met on installing the primary barrier.

The cost estimation for the section milling with successive under-reaming alone in this part amounts to just over 26 million NOK.

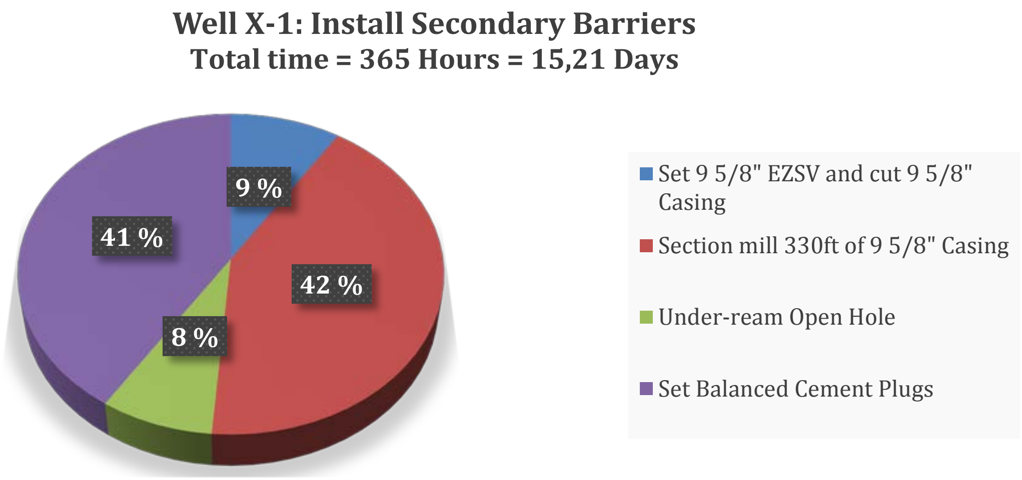


Figure 37: Detailed Secondary Barriers, X-1

The initial plan for the installation of the secondary barriers in figure 37 differs from the primary in the sense that there are two separate plugs to be placed, a requirement set by the operator in this specific formation. This is a typical case where the requirements of the operating company are stricter than the ones suggested by NORSOK. In any case, it means that the section that is to be milled is twice as long to accommodate (330ft ≈ 100m). Even so, it can be seen by figure 37 that the milling and under-reaming represent 50% of the time consumption, compared to the 61% for the primary barrier.

Comparing the actual reported ROP for the milling on the primary and secondary barriers, it can be found that the 6,2 ft./hr. is slightly increased to a reported 6,6 ft./hr. for the secondary barrier milling. However, the operation did not go as smoothly as planned and serves as an example of the many contingencies of section milling.

As the milling of the 9 5/8” casing commenced at 5537 ft., it was soon revealed that although pack-off was present on two occasions - it was not as big of an issue as with the primary barrier. As a result, the milling operation ran somewhat as planned for 62 ft. At 5599 ft. there was a sudden stop in progress, and the crew observed high bending forces and a “flat” torque level. Several techniques were tested to keep milling, but all ended in failure and caused them to trip out of the hole. As the BHA rose above the drilling floor, it was observed that the taper mill along with a joint of 5” drillpipe was missing. Instead of fishing it out, it was decided to push it further down the hole – a successful operation that left the broken off taper mill and joint out of harm’s way at 5940 ft.

The milling of the 9 5/8” casing continued and ran fine for another 43 ft., before the WOB suddenly dropped. Again several techniques were tested to continue milling, but it ended with another tripping out of the hole. Once more the equipment below the section mill on the BHA was broken off, this time with a choke sub in addition to the taper mill and drillpipe joint. This time the broken off BHA was jammed in such a way that it would not barge. As a result, the P&A plan were altered, leaving the milled section at 105 ft. instead of 330 ft.

The company requires the secondary barriers to be set below the 13 3/8” casing shoe (CS), which in this case was at 5591 ft. To avoid further problems with the broken BHA, it was decided to under-ream from the 13 3/8” CS down to 5620 ft., 20 ft. above the jammed BHA.

A balanced cement plug were then set from the top of the fish (TOF) up to a depth of 5390 ft., forming a barrier behind the part of the 9 5/8” casing that was a part of the new barrier position but had not been milled. As the cement had set it was then drilled out to the TOF. Doing so forms a solid base for a new barrier to be set, a concern brought on by the fish that was not sealing the entire hole.

To finish setting the secondary barrier, the open-hole section was once again under-reamed to 17 ½” to expose the formation. A new cement barrier was then set in the hole, measuring 617 ft. in length and ending at 5025 ft.

All in all it describes why the setting of cement plugs increases from 37 hours in the primary barrier, to 149 hours in the secondary. Although only 105 ft. of the planned 330 ft. of casing were milled and under-reamed, given the problems encountered it still took 182,5 hours to complete.

The occasional loss of equipment is included in the daily rig rate of four million NOK/day, which leaves the cost estimate for the section milling at 30,4 million NOK for the setting of the secondary barriers.

7.3.1.2 Case 2: Well X-2

As with case 1, the well X-2 features a jack-up rig to perform the P&A operation in a similar environment.

The time breakdown of the main operational sequences is presented in figure 38. The breakdown is an illustration of the activities presented in appendix B.

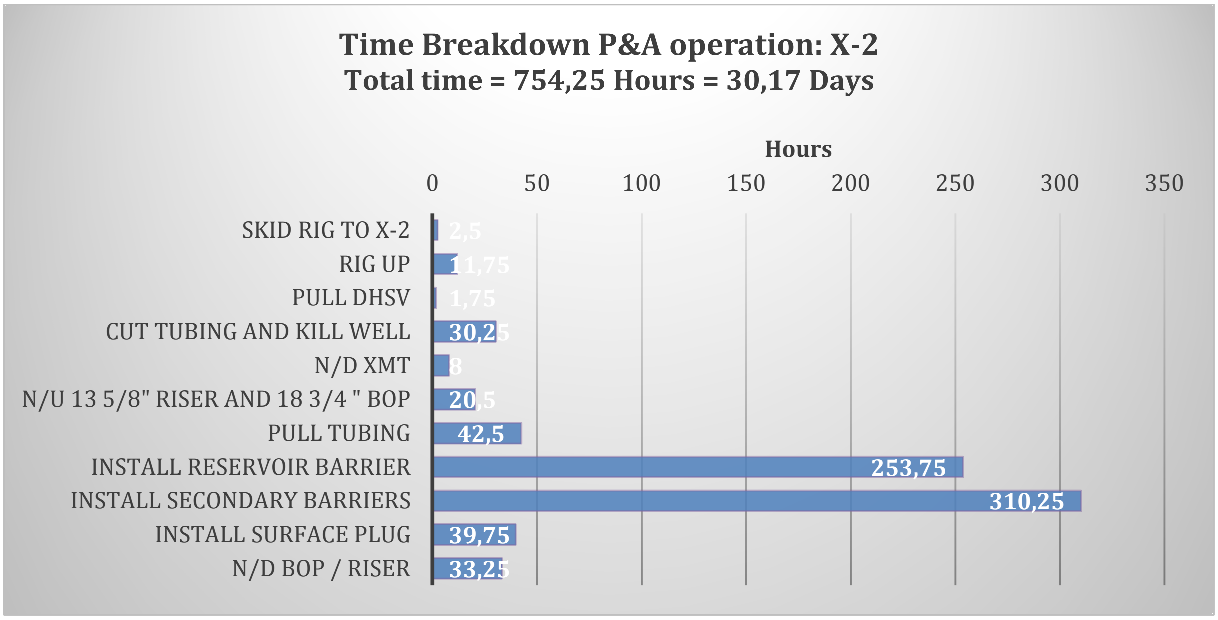


Figure 38: Time Breakdown, P&A X-2

From figure 38 it can be perceived that the time consumption is as expected from the previously investigated X-1, and X-2 shows the exact same trends. Compared to X-1, well X-2 it is a shorter operation stretching on for 31,43 days. Even so, the large amount of time spent on installing the barriers means that 34% of the total time is spent on the installation of the reservoir barrier, and 41% on the secondary – a total of 75%.

This means that of an estimated 125,7 million NOK for the P&A operation, installation of the primary and secondary barriers represents around 94 million NOK of it.

Figure 39 gives a more detailed look into what part of the installation of the reservoir (primary) barrier that was most challenging.

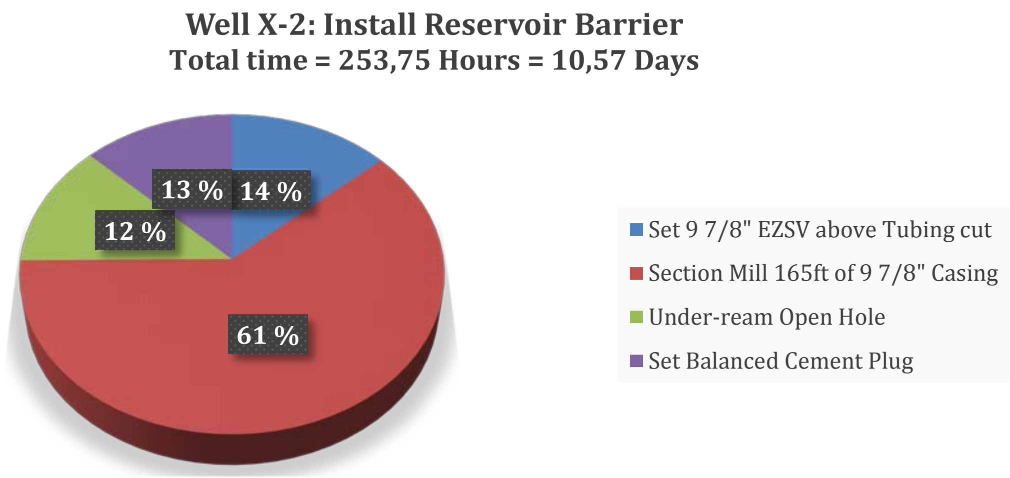


Figure 39: Detailed Reservoir Barrier, X-2

As it is perceived from figure 39, the section milling and under-reaming stands for 73% of the time it took to install the reservoir barrier. Investigation into the operations report shows the contingencies met on the installation.

As the milling parameters were established and the operation commenced, pack-off tendencies were revealed straight away. The tendencies were observed after each foot of milling, and created a birds nest after just 18 ft. of milling.

At 10 809 ft. the preventive methods were not enough, resulting in a stuck pipe. Several attempts of overpull and down weight were attempted, and after six attempts the pipe had moved 20 ft. upwards, but were still stuck. After spending something more than a full day on this, the pipe was finally pulled free by applying 420 000 lbs. of overpull a total of three times. The incident with a stuck pipe wasted a total of 34,75 hours.

After freeing the pipe, the section milling went on with the same pack-off tendencies as before, and it was checked every 4-5 ft. for build up of swarf.

The hole packed off again at 10 826 ft., but was quick to loosen the grip this time. However, after another 30 ft. of milling there was a sudden drop inn pump pressure, which stopped the operation. As it started up again, there was no increase in torque to be seen. This indicated either worn or retracted cutters, which called for a trip out of the hole. The mill was switched out along with Baker Hughes' SENTIO tool, which had been damaged under the stuck pipe incident. The SENTIO is a downhole data acquisition tool that is further discussed in section 7.3.3.

The ROP ranged from 1,4 ft./hr. to 4,3 ft./hr. with an average of 2,8 ft./hr. during the operation.

Under-reaming the open-hole section from 12” to 16” was an operation that went smoothly and with normal parameters. Some time was spent tripping, but this is expected at such a depth.

The section milling and under-reaming parts of the installation of the reservoir took a total of 187,25 hours to complete, with an estimated cost of 31,2 mill NOK.

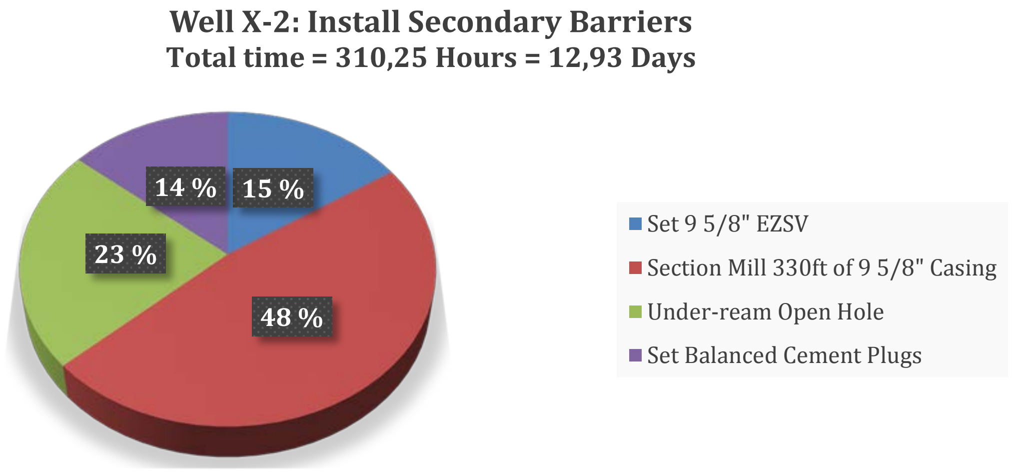


Figure 40: Detailed Secondary Barriers, X-2

Just like the installation of the secondary barriers in X-1, this is an operation that had planned for two barriers and 330 ft. of section milling. Quite *unlike* X-1 it was an operation without the biggest of issues. As it is understood from figure 40, the section milling and under-reaming for the secondary barriers on X-2 was responsible for 71% of the time consumption.

Just after the milling parameters had been established and the operation had commenced, concerns about the ECD arose. ECD is the effective density exerted by circulating a fluid against the formation, and is further described in section 7.3.2.
Concerns about ECD caused the crew to pick up the mill several times during the operation to adjust the mud weight, but did not lead to major time delays.

At 5892 ft. there was reported good indications of worn out knives, after had milled a total of 155 ft. This was accepted, and the milling assembly was tripped out and the knives were changed – with 100 % wear.

As the milling operation continued, there was a reported pack-off and stuck pipe at 6074 ft. Thankfully the pipe was not jammed as hard as for the reservoir barrier, and was worked free with 130 000 lbs. of overpull. The issue with pack-off concludes the problems that were encountered during the section milling, and TD was met at 6155 ft.
The milling for the secondary barrier gave better ROP than the primary, with values ranging from 4 ft./hr. to 7 ft./hr. and an average of 5,4 ft./hr. In addition, at 5970-5982 ft. there was observed an increase in ROP with values of 10-20 ft./hr.

As seen from figure 40, under-reaming the open-hole section was more time consuming than previous examples. As the under-reaming assembly was run in hole to its intended position, it was attempted to establish the proper parameters for under-reaming. Each time this was attempted, the hole packed off and the operation had to stop. Eventually the assembly was pulled out of the hole for inspection, where the crew found it was in perfect order. A clean up assembly was run in hole to clean the entire section, of which milling swarf, formation cuttings and some cement were observed in return. During the clean up, pack-off tendencies were observed multiple times.
The clean-up operation was a success, and the following attempt to under-ream went without major issues. Even so, from the time under-reaming parameters was attempted to the point where the operation actually began was 48 hours.

The section milling and subsequent under-reaming for the secondary barriers on X-2 took a total of 218,75 hours to complete. The estimated cost of this part of the operation amounts to 36,5 million NOK.

7.3.1.3 Tripping Times

The operational term of tripping is, in the petroleum industry, used to describe the act of pulling the drillstring out of the wellbore and to run it back in again. It is performed by disconnecting the pipes from one another, either in singles or in stands (two or three pipes joined together to save time on disconnecting). It will typically be performed once an operation with a specific tool is completed (e.g. section milling), or that progressed has stalled due to probable BHA failure.

If the P&A operation in itself has no financial upside, then the tripping time is the part that adds no progress to an already expensive operation. As illustrated in figure 41, Statoil reports that during the plugback of development well from 2000-2010, a total of 24% of the time was spent on tripping, which amounts 1181 days. Using the previously assumed 35-day average for an operation today, this amounts to 8,4 days just in tripping for each operation.

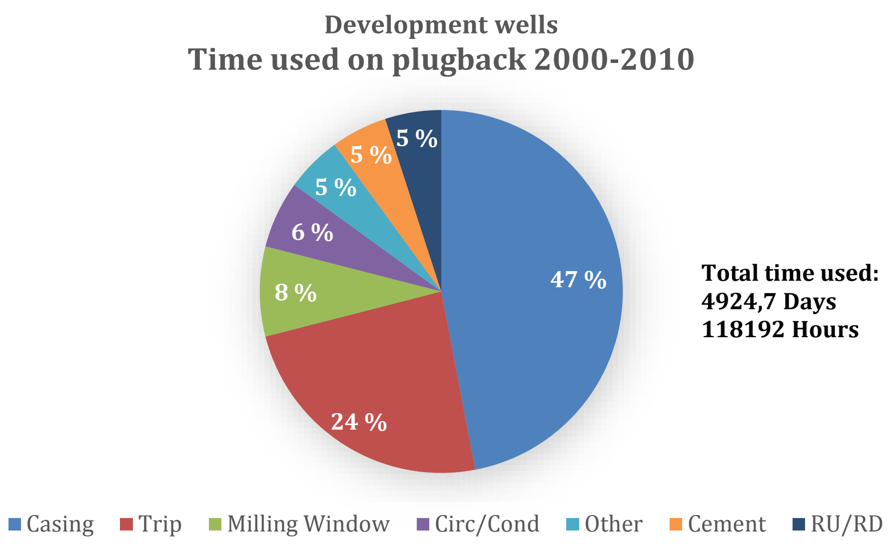


Figure 41: Time used on plugback, 2000-2010 (Statoil , 2014)

Although the different crews on the same rig can have individual differences on tripping time performance, it is not always the topside equipment that limits the tripping speed. While tripping out of or into the wellbore it is important that the hydraulic pressures be within the safe operating zone, which will be further described in section 7.3.2 and is illustrated in figure 46. If a tripping speed of a great magnitude were applied, it can cause a formation fracture (i.e. surge), a fluid influx (i.e. swabbing) or even a hole collapse (Chmela, Gibson, Abrahamsen, &

Bergerud). As a result, drilling crews are often faced with a dilemma between a good tripping speed and a safe operation.

To give a more specific picture on the issue and the actual times, further investigation into the operation reports of well X-1 and X-2 has yielded the graph presented in figure 42. It is a presentation on the time consumption spent on tripping alone, confined by the operational starting point of the section milling and the completion of the under-reaming. It also entangles the tripping of the operations that was a direct result of the section milling or under-reaming operations.

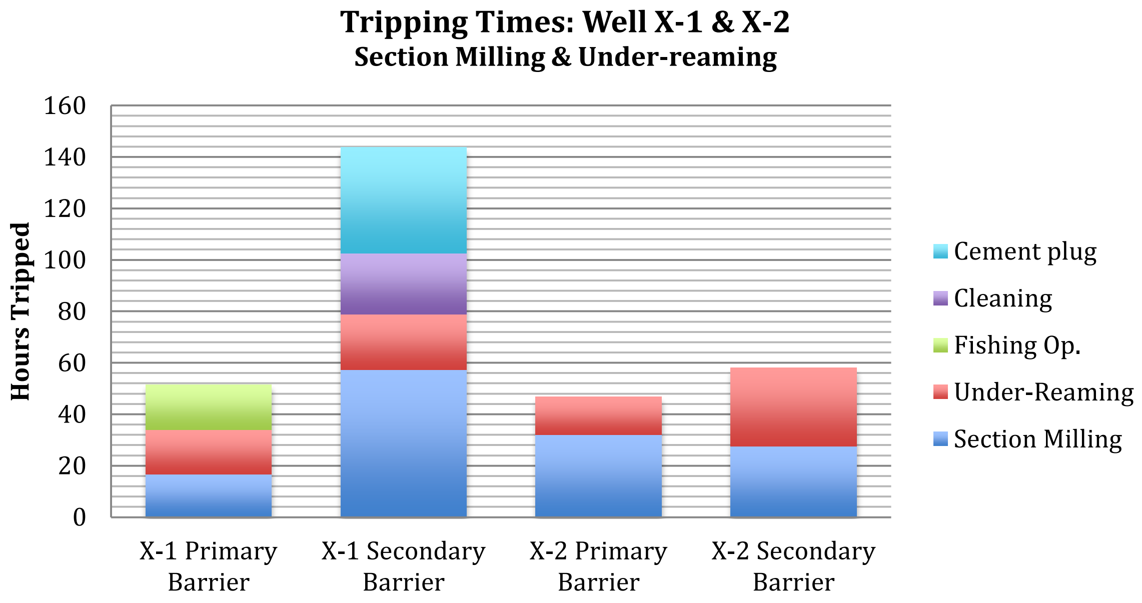


Figure 42: Detailed tripping times of well X-1 & X-2

As it can be perceived in figure 42, three of the four barrier placements had a somewhat similar tripping time. While the primary barrier is placed further down the wellbore than the secondary, the latter involves a longer section to be milled which leads to the need for two or more milling runs and naturally longer tripping time. This means that the tripping time of the two barriers can be expected to be somewhat equal, and has an expected average of 52 hours based on the operations and the contingencies described in the previous section on time consumption.

The placement of the secondary barrier in X-1 is chosen not to be a part of the expected average, but rather to be looked at as an example of how quickly the tripping times can multiply in the face of unforeseen events. Because the tripping time on this barrier alone was 133 hours,

combined with the 51 hours on the primary barrier the total tripping time on well X-1 is 184 hours (7,67 days). That adds up to a cost estimate of 30,67 mill NOK for an operation with no use for the operation more than to reach a depth.
The milder 46,75 hours and 58 hours for the barriers on well X-2 gives a total of 104,75 hours (4,37 days) and a cost estimate of 17,46 mill NOK.

To better this performance, many new rigs are fitted with a continuous motion system to perform tripping. This is an automated system with dual arms that continuously feed tubular in a steady pace and thus eliminating the start/stop method traditionally used. Even though the tripping speed itself is lower than traditional, the use of continuous motion promises to deliver up to 3600 m/hr. versus the traditional 600-900 m/hr. Studies and virtual testing show that this can reduce drill time by up to 50%, and reduce drilling costs by up to 40-45% (West Group).

7.3.2 Swarf Generation & Transport

Several conversations with operators confirm that swarf generation and the handling of it, is one of the major issues with section milling. The term "swarf" is, in this setting, used to describe the cuttings or metal shavings that are generated under the milling operations. The swarf needs to be removed before a WBE is set, as it can interfere with the cementing operation, giving a poor plug. It is indicated by Halliburton that a typical 50-meter section of milled 9 5/8" casing will generate around four metric tons of swarf (Halliburton). This will of course vary on conditions like the weight per feet, size, thickness and wear (corrosion and erosion) of the casing being milled.

Figure 43: Collection of swarf (Halliburton)

The information provided by Total E&P Norge given in appendix C show details around their latest milling operation (as of April 2015). It shows that the milling of their 10 ¾" casing collected 2,6 tons of swarf in just the first 16 meters, with another 5,1 collected for the next 19 meters. The swarf generated to total depth (TD) is not accounted for in the report, but a preliminary average of 0,226 tons/meter will see to it that an estimated collecting of about 11,3 tons of swarf at the TD of 262 meters. This amounts to a 50-meter section, which gives a pointer as to the magnitude of swarf in these operations.

However, the swarf collected topside does not tell the whole story, as Halliburton claims that some operators actually only manage to recover approximately 25% of the swarf that are generated downhole (Halliburton). This estimate was confirmed in a meeting with the very competent senior consultant Roy W. Rooyakkers of RoyCo Consultants (Rooyakkers, 2015). Rooyakkers adds that 25% is a poor number with insufficient transport and possible high deviation of the well, and that an operator would be able to recover around 55-70% with the proper parameters. Nevertheless, it still leaves at least 30% of the generated swarf in the wellbore to damage equipment and possible make the WBE insufficient.

If the hole cleaning achieved is poor, a "birds nest" may occur. This refers to a situation where there is a build-up of entangled steel slices that are stuck in the well. The bird nests will most often be found in exposed areas of reduced annular velocity, for example in the riser, BOP or liner hanger (Sandven, 2010). Modern cutter technology are designed to break off the cuttings into smaller pieces, as will be discussed in section 7.3.3 regarding cutters, but even these may build up and form small balls that can ultimately generate a birds nest.

In the cases under time consumption in section 7.3.1, pack-off was mentioned as a severe issue during the operations. Pack-off is basically to plug the wellbore around the drillstring and/or BHA. In this case, is was due to poor removal of the swarf that was generated, which caused it to jam around the drillstring. As this happens the drilling crew can measure a sudden reduction or loss of the ability to circulate, and will observe a large pump pressure (Schlumberger, 2015).

Swarf that is successfully transported can become strung out as it moves upwards, lodging in the annular and ram BOP equipment. For example, a birds nest in the BOP would restrict the flow and transport, and even the pipe movement. The BOP is the final barrier against blowouts, and as a result the BOP needs to be carefully monitored under the operation, and inspected and cleaned of residual swarf afterwards. Swarf transport is listed as one of the main causes for BOP failure (Halliburton).

The topside handling of the swarf brings with it some HSE issues. The rig personnel involved is exposed to metal cuttings with razor sharp edges, and so the proper protective equipment must be used to avoid unwanted events and injuries.

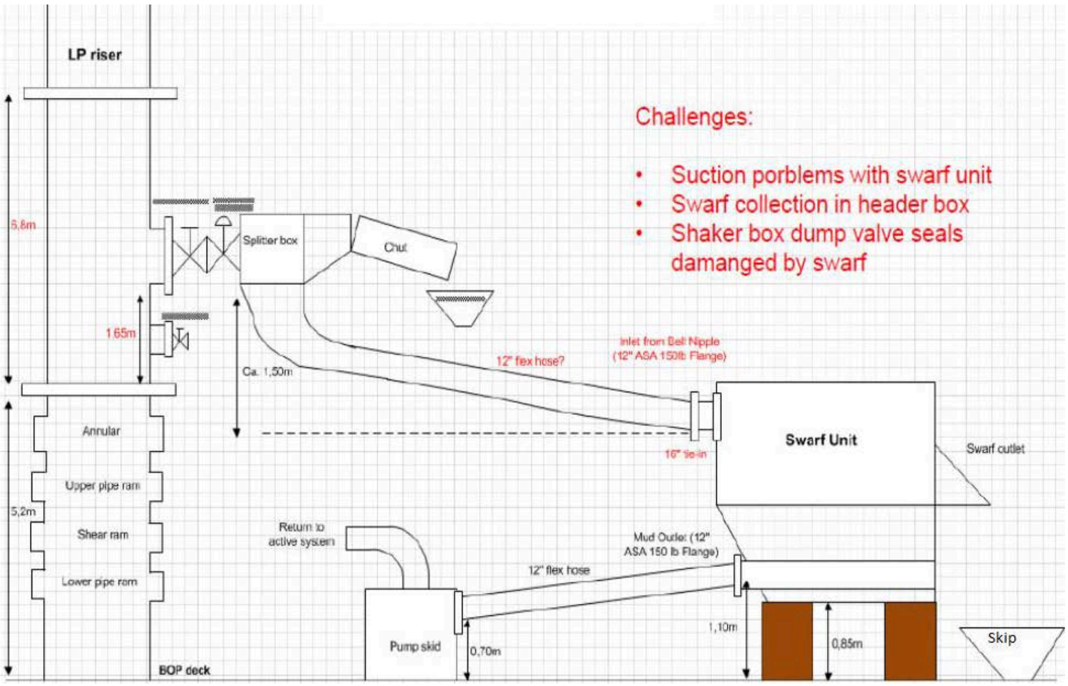


Figure 44: Swarf handling equipment on Gullfaks A (Randby, 2014)

While some rigs includes the topside equipment needed for swarf handling, others does not and have to spend time and expenses on installing it for each operation, see appendix C. An example of the handling unit on Gullfaks A is given in figure 44, along with common challenges. Other special considerations to take are to eliminate tight bends in flow-lines and ensure good clean-out capabilities and a sufficient drop (Sandven, 2010). The handling equipment on the rig is installed within the return flowline, beyond the bell nipple and in front of the shakers. This will try to ensure the separation and capture metal returns from the active mud system (Ferg, et al., 2012). The collected swarf will be loaded into skips (containers), which needs to be changed out when full. Fine steel particles can escape via the fluid and damage pumps etc. To solve this, magnets are often used after the shaker screens to collect it.
Logistics are then set in motion to transport the skips onshore and so to ensure the proper disposal of the swarf.

7.3.2.1 Milling Fluid

Removal of the swarf happens through the circulation of special milling fluid or mud created specifically for that particular job. The mud used for milling is thicker than the one being used for tripping, and the fear of swab or surge is the reason why they are switched before an operation. Given the amount of swarf that is generated, the ability to transport it out of the wellbore will often be a limiting factor operations efficiency. The fluid that is used needs to have sufficient viscosity to transport swarf to the surface, and it is typically desired to have as high viscosity as possible while keeping the open hole stable.

The most important parameters for the lifting capacity of the milling fluid is recognized as:

- Flow
- Viscosity
- Angle of the wellbore
- Temperature
- RPM
- Weight and size of the cuttings
- Annular flow velocity

(Nesheim, 2015)

There are several advanced fluids available for this use, but in a meeting with project manager support DS Gunvald Nesheim of M-I SWACO it is explained that the most basic fluids are often the best ones (Nesheim, 2015). Basic fluids in this case are systems constructed on the water-based mud (WBM) KCl (potassium chloride) polymer, often with a yield point of about 70-90 lb./100ft^2. There are several reasons for this, the first being that they are easily controlled with regards to viscosity alterations during the operation. Another one is the concern about the old mud behind the casing as the tool cuts through, where a common problem is inhibition if the formation is exposed (Nesheim, 2015). It is important to have knowledge about what type of mud exist behind the casing and how it will affect the milling mud being utilized, especially in cases where WBM meets oil-based mud (OBM). The simple milling fluid system is good here in the sense that it can handle a big amount of contamination of both cement and of OBM. Contamination of KCl polymer mud with OBM from behind the casing actually has a positive effect up to a maximum of 10% (Nesheim, 2015). The common WBM’s are presented in figure 45.

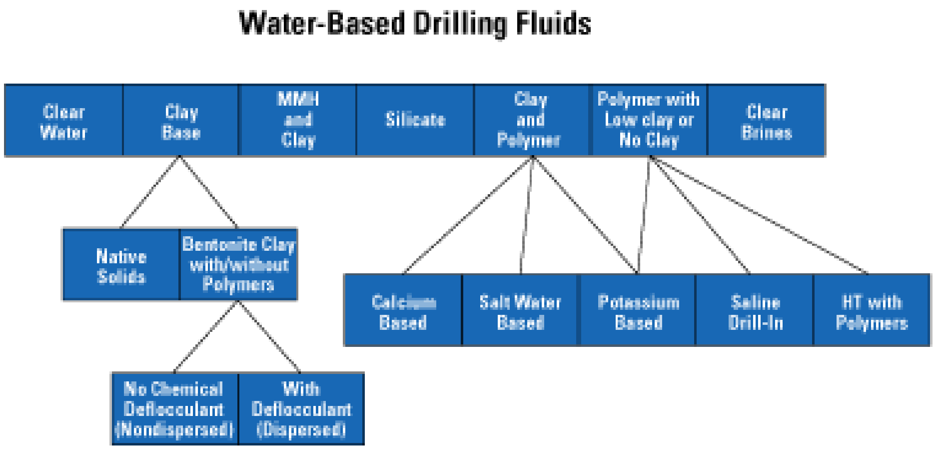


Figure 45: Water-Based Drilling Fluids (Schlumberger, 2015)

OBM's are harder to manipulate in the sense of viscosity making it more time consuming and expensive, in addition to the already added expense of the mud itself. As a result, OBM is rarely used as a milling fluid. However, it can be used in cases where there are only to be milled a few feet and there are generated small amounts of swarf, or because of equivalent circulating density (ECD) limits where the OBM are gentler. Other advantages of the OBM are that the WBM are much more corrosive on the steel of the drillpipe, along with influence of gas-cut where the WBM are in greater danger of having the density lowered (and thus, lifting capacity) due to gas intrusion into the mud (Nesheim, 2015).

While it is important to keep a sufficient weight and the viscosity of the fluid high, this will also create other issues. Milling and under-reaming will leave the formation exposed, making it vulnerable to the pressures inside the well. The mud used in these operations will normally be designed to stay somewhere between the fracture gradient (FG) and the pore pressure (PP) of the formation. The method is visualized in figure 46, and is generally referred to as the "median line principle". Especially in deep section milling with heavy fluid systems, it can be a problem to stay between these lines. A solution in these cases will often be to reduce the pump pressure, and so to lose some of the effect in the hole cleaning (Nesheim, 2015).

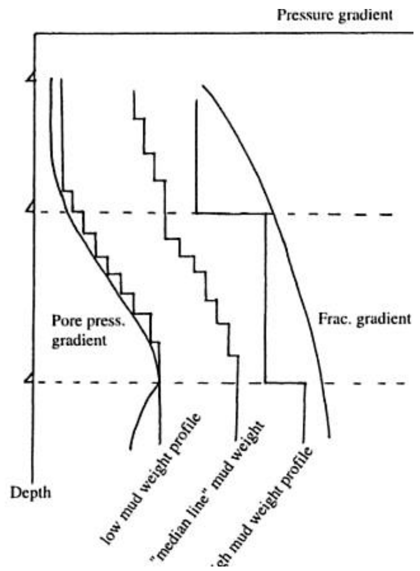


Figure 46: Mud Weight Profiles (Aadnøy, 2010)

Increasing the mentioned characteristics while also often increasing the pumping rate can generate an ECD that exceeds the fracture gradient of the formation. This is especially sensitive if the hole were to pack-off causing a pressure increase. The ECD is calculated by the following formula (Schlumberger, 2015):

$$ECD = d + \frac{P}{0.052 * D}$$

where,
d = mud weight in ppg (pounds per gallon)
P = pressure drop in the annulus (psi)
D = true vertical depth (feet)

The ECD is the effective density exerted by a circulating fluid against the formation. It is an important parameter in avoiding kicks and losses. If the formation is fractured, it reveals a world of issues; losses while circulating, swabbing, well control problems, poor hole cleaning and pack-off (Ferg, et al., 2012). As it can be visualized from figure 46, the closer the PP and FG is, the more difficult it is to ensure transport and well control. As a result, it is important for the efficiency of the operation to find a "sweet spot" where the ROP, flow, pump pressure and viscosity are all working optimal to have the best hole cleaning.

After the job is completed and the milling fluid is no longer needed, normal procedure is to inject all the fluid, as it is unwanted to bring crude back onshore.

7.3.3 Wear of the Mill

As previously stated, section milling is an operation that is performed only when it is absolutely needed. As a result, it is important to refine the technology to an extent where it performs optimal when it is required.

As the milling proceeds, the mill will be worn out in a pace that is dependent on several factors. The chemistry and geometry of the cutters themselves, along with angle of attack, quality of the casing, cement in annulus and weight applied is all contributing to this wear. A worn out mill will perform poorly, and needs to be changed out in an operation that takes extra time to perform.

To address the challenge, the following will be an investigation into the cutters that is used to perform a section milling operation, including some historical development and the main factors of optimal performance.

7.3.3.1 The Cutters

The substance used for the cutters in milling is called tungsten carbide. It is the optimum hard facing material that is available for its milling purpose, with a hardness about 150 times that of normal steel. It is by no means new, and has been used for downhole metal cutting and wear-resistance since the 1930s (Stowe & Ponder, 2011). The geometry and technique, however, has been altered.
One of the most common structures of the cutters has been of randomly crushed, sintered tungsten particles composed in a matrix of a special copper-based brazing-type alloy with high nickel content (Scanlon, Garfield, & Brobak, 2011).

In the mid 80’s, the introduction of carbide inserts into the cutting matrix was introduced, a change that increased penetration rates and lifetime of the mill at that point by up to 1000% (Scanlon, Garfield, & Brobak, 2011). The aggressive design of the new cutters had higher penetration rates, smaller cuttings and extended the lifetime. The inserts were made by pressing tungsten carbide powder into a mould to give a circular shape. These circular shaped inserts is what was used for, amongst many others, section milling. For this purpose they were arranged in such a way to form a blade, commonly referred to as “knives” like the one seen on the left hand side in figure 48.

The cutters stayed in this spec for a long time, before in 2000 the chemistry was altered to powder carbide. The powdered metallurgy structure has a greater toughness than the solid tungsten carbide (Stowe & Ponder, 2011). This is an important progress in the sense that the weight applied on the mill can have a tendency to create vibrations of such a magnitude as to shatter the cutters.

The progress of the cutter’s evolution is summarized in table 10.

Table 10: Progress of cutter technology(Scanlon, Garfield, & Brobak, 2011)

Material	Manufacturing	Application	Features
Tungsten Carbide	Randomly crushed	Multiple applications	- Tight control of manufacturing process assured uniformity and quality - Highest quality cutting carbide used for enhanced performance - Rod form for easy application
Powder Carbide	Pressing tungsten carbide powder into a mould for a circular shape	Aggressive cutting structure for cutting alloys	- Higher penetration rates - Smaller cuttings - Extended mill life
Powder Carbide	Pressing tungsten carbide powder into a mould for a particular, identical shape	Multiple applications	- Optimum shaped geometry assures sharp cutting edges and points are looking down no matter how the insert is positioned - Ideal for dressing cutting/milling tools to exact OD’s and ID’s - Dual concave ends for optimum exposure of cutting points - Rod form for easy application
Improved Recipe of the Materials	Pressing tungsten carbide powder into a mould for longer cutter of a specific shape	Milling requiring long lasting cutters	- Material developed for long duration - Not susceptible to single point loading - Chip breaker incorporated into each insert - Maximum impact resistance value for each cutter

The cutters being used today still consists of the tungsten carbide powder, but the cutters themselves can be specified to any geometry that is required. Some examples of these designs can be seen in figure 47. One of the most important features of the modern cutters is the feature called “chip breaker” (Rooyakkers, 2015). The chip breaker’s job lies within the name, and is to reduce the effective length of the cuttings that are being generated. This will allow them to be circulated back to the surface easier, an issue previously discussed in section 7.3.2. Ideally, the cuttings should be in the length of around 1 inch to avoid bird nests but still have enough surface area to be effectively transported (Rooyakkers, 2015). The geometry of the chip breaker is also something that can be customized for each situation, and in figure 47 it can be seen as the concave area that is placed inside the edge on most of the cutters.

Figure 47: Cutter geometry examples(Alibaba.com, 2015)

Table 11 is from an operation on ConocoPhillips’ well W-04, where the whole P&A operation took 70,1 days to complete (not including WOW). The table shows a breakdown of the time spent on milling the 9 5/8” casing to set barrier number two (Scanlon, Garfield, & Brobak, 2011). As it shows, five runs were needed before the operation came to a halt due to difficulties on entering the casing stump. A total of three runs were needed because of 100% worn out knives. To get a sense of the cutters importance on the milling operation’s performance, the improvement campaign that followed will be further discussed.

Table 11: W-04 Section Milling runs & times (Scanlon, Garfield, & Brobak, 2011)

Run No.	From (ft.)	To (ft.)	Hours Total	ROP Total (ft./day)	Hours on Btm.	ROP on Btm. (ft./hr.)	Comments
1	11608	11666	61,25	25,5	15,5	3,7	Reason for pulling – knives 100% worn
2	11666	11666	32,25	n/a	0	n/a	Mis-run, knife arms failed to open
3	11666	11728	4,5	30,1	27,75	2,2	Reason for pulling – knives 100% worn
4	11728	11745	35,25	11.7	4,75	3,6	Reason for pulling – knives 100% worn
5	11745	11749	32,25	3,2	2,25	1,8	Reason for pulling: Could not enter casing stump
Total	**141**		**213,5**		**50,25**		

In 2009, ConocoPhillips stood before a challenge on six Whiskey wells that included significant section milling. Two previous wells had been abandoned with an average of 65 days, which they felt was too high combined with added requirements for the milling of the remaining wells. They joined forces with Baker Hughes with the goal reducing the time consumption by completing a 165 ft. milling operation in a single run.

Two new technologies were implemented; one of them was a downhole optimization sub, a tool that gathered real-time data from the bottom hole assembly (BHA) and sent to the engineers. The other was a new and improved form of cutters.

Figure 48: Old Cutter Design vs. New Cutter Design (Stowe & Ponder, 2011)

Several types of cutters existed at this point, but the ones named “P-cutters” was the latest addition, and an example can be seen in figure 48 and in figure 49.

The new cutters contained several advantages. Numerous formulas of the chemistry had been tested in a lab, and the result was tungsten carbide cutters that provided both improved impact and wear resistance. This longer lifetime of the material was an important factor towards a long stint of section milling.

Another improvement was the geometry of the cutter itself. The circular shape had been altered to a more squared form with a longer cutting edge. This meant that it was not susceptible to single point loading that the old design could suffer, and it gave a more evenly load on the cutter which in turn gave extended life (Scanlon, Garfield, & Brobak, 2011). It also reduced the rubbing area, which gave a way for faster cutting.

Figure 49: New Cutter Design (Stowe & Ponder, 2011)

An additional feature that was incorporated into the new design was the earlier mentioned chip breaker. The effect was verified on this campaign, where there was a significant reduction in the length of the cuttings as well as the amount of long stringers that is commonly associated with section milling (Scanlon, Garfield, & Brobak, 2011).

7.3.3.1.1 Results From ConocoPhillips (Scanlon, Garfield, & Brobak, 2011)

In addition to the new cutters, the use of the downhole optimization sub on well W-03 gave a reduction of the time spent on circulation and with no reported losses to the formation. Compared to other wells, over four days of operating time was saved compared to previous milled sections – with subsequent wells showing similar or better trends.

Downhole parameters such as WOB, torque and vibrations could be monitored and altered better throughout the operation. Under deep section milling, vibrations were at a low level in both whirl, lateral and axial.

More shallower section milling showed that the issue with high ECD was not as severe it has been observed before, due to lower mud weight. However, there was an issue with high doglegs in some areas of the casing, which can lead to high level of vibrations and bending moments.

The overall result can be viewed in figure 50 and figure 51. The new cutter technology improved the performance significantly, and it was quickly acknowledged that they exhibited a level of impact resistance that had not previously been seen on these types of operations. The result was eminent, giving an average of 1,5 trips per well on the 10 wells included. It was also reported a more consistent cutting operation than normal.
From figure 51 it can be perceived that the rate of penetration (ROP) was increased and the milling time had decreased considerably, giving a significant lower time for the operation and saving costs.

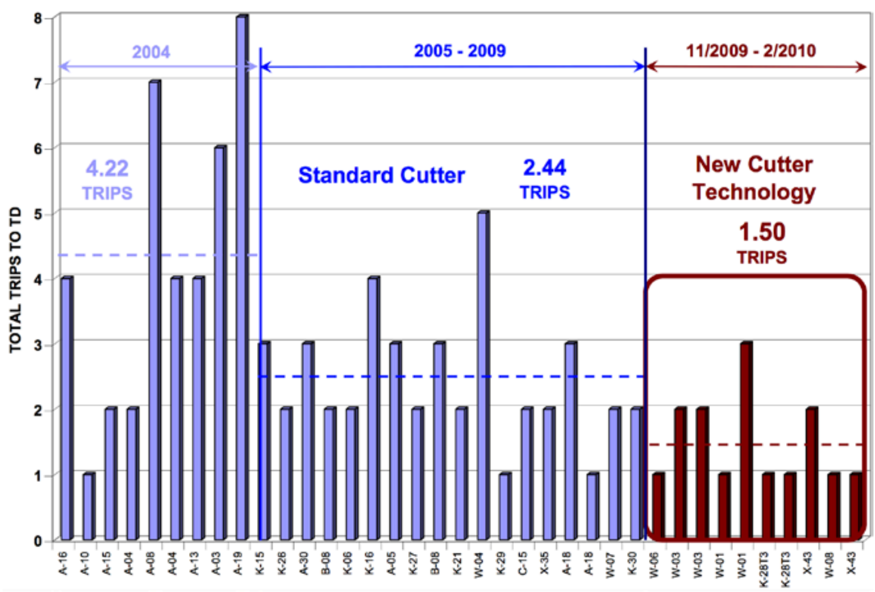


Figure 50: Historical Improvement (Stowe & Ponder, 2011)

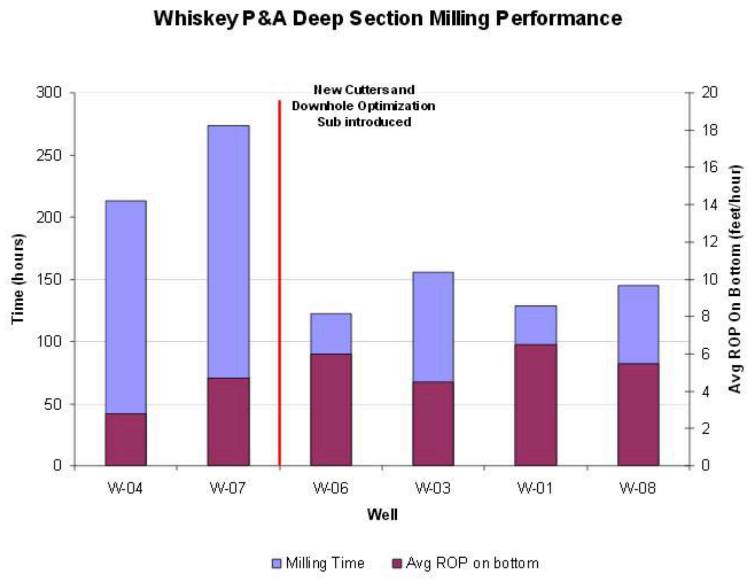


Figure 51: Deep Section Milling Performance Before & After Introduction of New Technology (Scanlon, Garfield, & Brobak, 2011)

7.3.4 Plug Verification

As the on-going operation matures to a point where the barrier element in the well has been placed in the right section, it needs to be tested. Verification if the barrier's ability to seal the entire wellbore is essential to the P&A operation. As previously discussed, table 15 in NORSOK rev. 4 shows the acceptance criteria for a cement plug to be done by pressure testing or by tagging the plug (NORSOK D-010 Rev.4, 2013).

When setting the plug in a milled section, there are two predominant ways of doing so: either to leave the TOC inside the casing above the milled window, or to leave the TOC inside the hole (Ferg, et al., 2012).

If the TOC is inside the cased hole, the way of evaluating the element is to tag the TOC, apply weight and then to pressure test it. Because of the nature of the balanced plug method that is used, these tests will only evaluate the cement that is inside the casing – not the cement in the annulus or the open hole.
If the TOC is left inside the open-hole section, tagging is used to verify setting depth. In these cases it becomes near impossible to perform a true pressure test, due to the fear of fracturing the formation that is left exposed over the barrier.
In either one of these cases, the sealing capability of the plug is difficult to assess (Ferg, et al., 2012).

7.3.5 Vibrations

When discussing the cutter design, improvements in vibration control were mentioned as a factor. The milling operation is described as a violent operation with respects to the vibrations that occur and what affect it has on equipment. As the cutters grinds away the metal of the casing the downhole mill develops high level of axial and torsional vibrations.
The problem is prevalent in low torque situations, where small and rapid movements of the rig during cutting can transplant into the mill, causing it to take cuts of irregular depths. The vibrations that are generated will in turn intensify the irregularity of the cuttings, which will feed the irregular rapid movements and vibrations. In any case this will result in a reduction of ROP and can damage the equipment in the BHA (Blizzard, Carter, & Roberts, 1996).
The mill itself will often incorporate stabilization to try to moderate these vibrations, but the BHA will still have to manage considerable impact (Stowe & Ponder, 2011).

In recent years, there have been improvements in dealing with the challenge of vibrations. During ConocoPhillips' Whiskey campaign, discussed in section 7.3.3.1, an optimization sub was an important technology implemented to improve the section milling. It was incorporated into the BHA to acquire downhole parameters and pair them with surface data to give the engineers a richer picture of the operation. Along with measurements of vibrations, it gathered information about weight on tool, torque, RPM, bending moment, pressure and temperature. The implementation of this tool is thought of as a milestone with regards to vibration control (Scanlon, Garfield, & Brobak, 2011).

The deep section milling operations that was run on Whiskey actually showed relatively low levels of vibrations, and steady values throughout. There were some peaks in lateral vibrations, but this was considered not to be of significant concern. The true value of the optimization sub was that in the event of high levels of vibrations, the appropriate counter-measures could be applied to manage the situation. This meant that major damage to the mill or other parts of the BHA could, to a large extent, be avoided (Scanlon, Garfield, & Brobak, 2011).

Figure 52 shows a typical example of the real-time data collected during the operation. The two lines furthest to the represent the axial and lateral vibrations, and it can be perceived from them a moderate and steady rate.

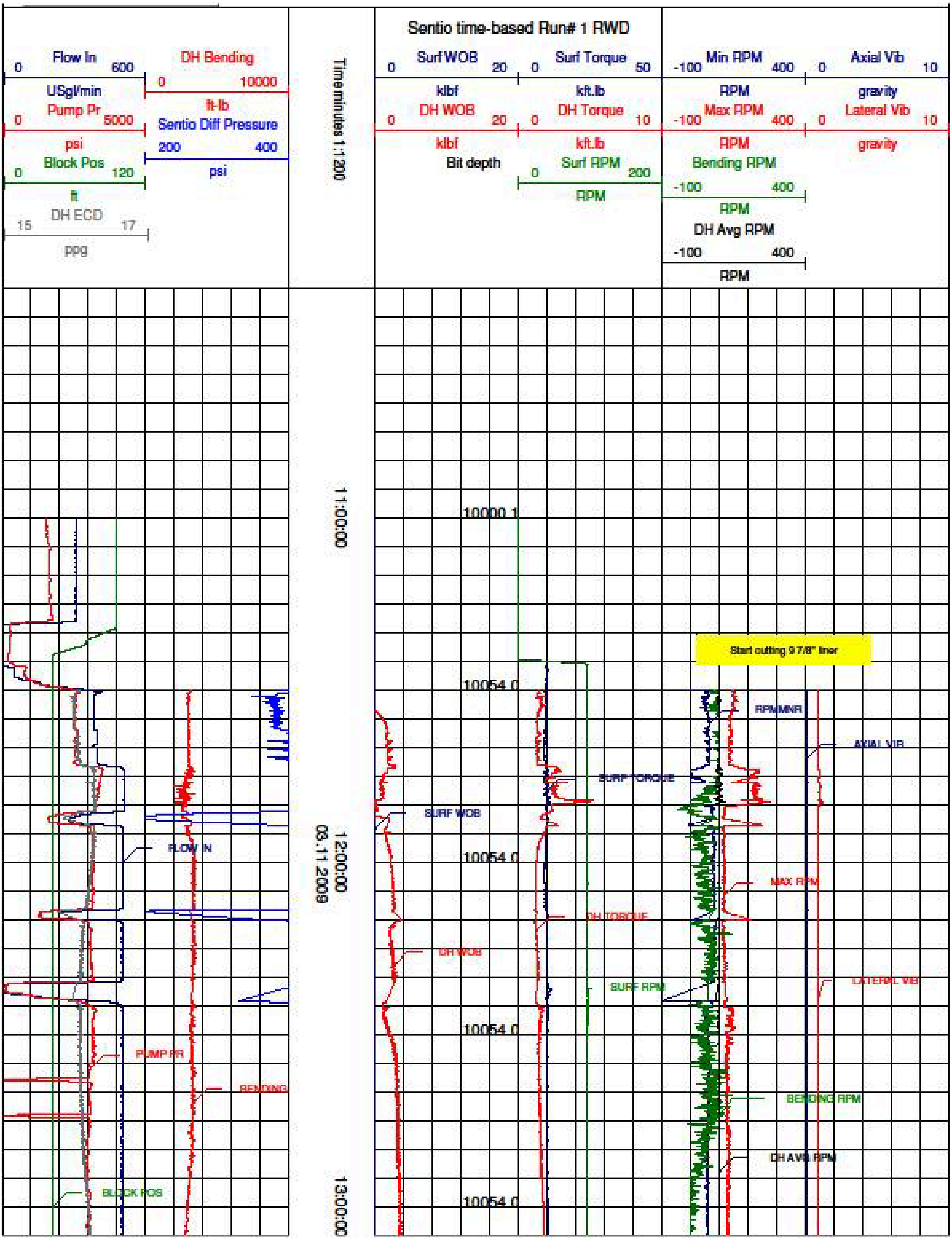


Figure 52: Real-time Downhole Data (Stowe & Ponder, 2011)

8 Improvements & Alternatives

Up to this point of the thesis the main focus has been on the section milling technology, its challenges and areas in need of further progression. Every piece of technology is refined to a degree where progress is stalled and where the alternatives become the most sought after technology. This chapter will focus on the alternative technology that shows potential with regards to replacing section milling and how it can achieve this.

8.1 PWC Technology & HydraWell

HydraWell Intervention AS is a company founded in Stavanger, Norway in 2008. In their own words, they “shall design tools and solutions which are technologically cutting edge and provide optimum performance, safe handling and efficient operations.” (HydraWell, 2015)

HydraWell incorporates an innovative P&A technology commonly referred to as “perforate, wash and cement”. The operational sequence lies within the phrase, which is to perforate the casing rather than to mill it, to wash away cement and/or formation behind it and then to set a cement plug. Just like in section milling the mud weight needs to be sufficient to maintain the stability of the exposed formation. However, as there is no swarf generated, high-viscosity milling fluids are not needed to lift the metal debris from the wellbore (Ferg, et al., 2012). In addition, the casing will be left primarily intact, allowing for a re-entry on a later occasion.

The technology strongly reduces pack-off tendencies, which were a major factor in the section milling cases previously discussed. No swarf also provides a safer working environment for the workers, along with environmental advantages of not having to dispose of the metal cuttings that are generated. The topside equipment for swarf handling is also deemed unnecessary, which recuses costs. (Ferg, et al., 2012)

The method can be run either as a single-run or a dual-run, as seen in the chart presented in figure 53. The charts also presents HydraWell's own operational times where it is compared to the traditional section milling discussed in this thesis. As perceived, there are a 57% decrease in time consumption for the dual-run, and a 71% decrease for the single-run, compared to the section mill operation (HydraWell Intervention, 2015).

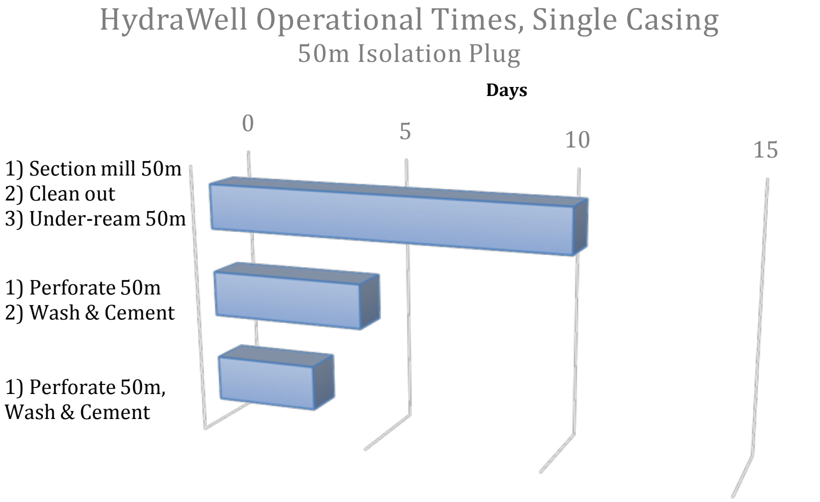


Figure 53:HydraWell Operational Times, Single Casing (HydraWell Intervention, 2015)

8.1.1 The Tools & Operations for Single Casing

Because the operation can be performed in a single run, it presents a need to describe the tools that achieves this. The tools that are run in operations where a well with a single casing is to be plugged can mainly be separated into three pieces: a tubing-conveyed perforating (TCP) gun, the HydraWash and the HydraArchimedes. They can be run on standard drillpipe and in the sequence given in figure 54.

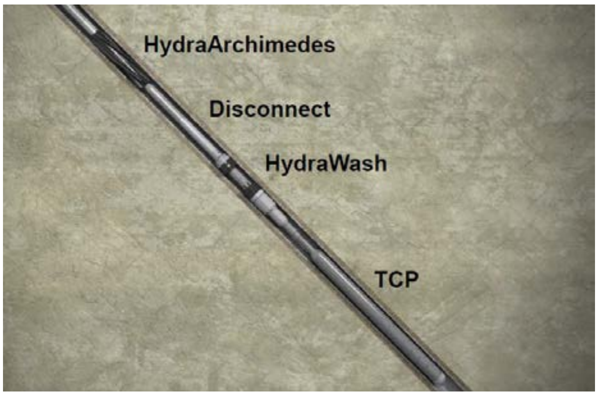


Figure 54: HydraWell Intervention tools (HydraWell Intervention, 2015)

Normally, to RIH with a solid tool and a small clearance would be likely to give a surge in the wellbore. To avoid this, the HydraWash tool incorporates several bypass conduits that diverts the mud around the tool and above it. As a result, the tripping speed can be determined by the TCP gun's recommendations or the more natural limitations of the rig and crew itself.

When the tool reaches the pre-determined depth, the perforations will go off and punch holes in the casing and formation. The perforating guns shoots 12 shots per foot (SPF) in 135/45 degree phasing. The top and bottom seven ft. of the guns are loaded with chargers that makes larger perforations to facilitate easier washing without exceeding formation fracture pressure, while the remaining are based upon the principle of limited entry perforating backpressure (Ferg, et al., 2012). The TCP gun is disconnected and dropped after the perforation is complete, and is left in the hole itself. A limiting factor in this case can be the length of the rat hole, which if not big enough for the disconnected 200ft. long TCP gun, forces the operation to use dual-runs.

8.1.1.1 HydraWash

Now at the bottom of the BHA is the HydraWash. The HydraWash tool is used to wash and clean out debris, old mud, barite, old cuttings and cement traces in the annulus behind the casing. The washing is illustrated in figure 55, with mud-flow coming from the bottom elastomer cup to clean the annulus and return the debris to surface. The activation of this feature is achieved by dropping a ball to divert the flow, and the annulus is then cleaned until sufficient pump rates with minimal pressures has been achieved. It washes one ft. of the casing (12 perforations) in one continuous movement of the tool. The backpressures vary because of the variations of perforation sizes, but the mid gun assembly diameters are designed to create between 55-75 psi of backpressure across the 12 open perforations (Ferg, et al., 2012).

Figure 55: HydraWash Animation (HydraWell Intervention, 2015)

As the washers moves downwards it will create pressure variations when it passes the perforations that are closed with cement and debris, and it is this pressure regime that controls the process. As a pressure peak is encountered, the drillstring stalls until the pressure stabilizes which indicates that cleaning is achieved. This can be seen in figure 56, where a typical pressure curve for the washing is presented (Randby, 2014).

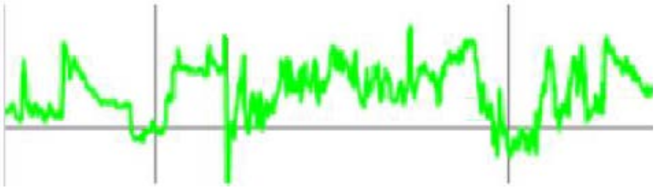


Figure 56: Typical washing curve, Example (Randby, 2014)

Although OBM allows for a higher wash rate than WBM, experience has shown that the OBM has a tendency to contaminate the cement. For this reason, in addition to being cheaper, WBM is preferred for the operation (Randby, 2014). The washing rate itself is then determined by the ECD, which is previously discussed under section 7.3.2 is a function of the formations fracture gradient, fracture pressure, well geometry and rheology. Also determined by the ECD is the perforation diameter itself, as they are a function or limited entry, wash rate and rheology (HydraWell Intervention, 2015). The pressure drop over the perforations are determined by the following formula:

$$\Delta P_{perf} = \frac{MUD_{PPG} * Q^2}{12035 * A_{perf}{}^2 * C_d{}^2}$$

where,

ΔP_{perf} = Differential pressure over perforation [psi]

MUD_{PPG} = Mud weight [ppg]

Q = Fluid flow [gpm]

A_{perf} = Area of perforation [in^2]

C_d = Factor = 0,95 (Accounts for a perforated hole rather than a perfect circular hole)

The time it takes complete the washing operation may vary, but in the handout provided by HydraWell Intervention it is within the time regime of 7,5 – 82 hours and with an average of 22,5 hours (HydraWell Intervention, 2015). It can therefore be the most time-consuming part of the operation.

As the interval is thoroughly enough cleaned, a spacer fluid is pumped into the section. Doing so helps to reduce the differences in viscosity and density and to avoid any contamination of the wet cement (Randby, 2014). A deactivation ball is then dropped which disconnects the lower part, the jetting tool, from the rest of the HydraWash. The jetting tool itself will then form a base for the cement plug, and the remaining HydraWash is diverted into a cement stinger. Because the elastomer cups on the HydraWash are of larger outer diameter (OD) than the casings inner diameter (ID) and with a high contact force, it creates a seal for the cement plug that is to be set.

With a clean annulus, a base for the plug and a cement stinger already in place – everything is set for the plugging material to be pumped. Before doing so, the string is pulled to a position above the top perforations and rotated at 100 to 120 RPM while pumping at the maximum loss-free rate to clear the wellbore of any remaining material washed from behind the casing (Ferg, et al., 2012). The cement stinger is then positioned at the base of the plug below the perforations, ready to start the cement job.

8.1.1.2 HydraArchimedes

Because the casing is still essentially in place, it can be hard to provide a good enough seal in the annulus by just pumping down cement. To address the issue, the HydraArchimedes is placed above the HydraWash. The tool can be seen in figure 57, and its purpose is to rotate while cementing, forcing the wet cement through the perforations and to fill the annulus.
The cementing operation takes place while the tool is rotated and POOH, and the principle behind the HydraArchimedes is that the helical rubber blades act on the cement hydraulically by creating a high/low pressure regime as it rotates, but also to use mechanical force to squeeze the cement through the perforations. Each HydraArchimedes tool treats 25 m of perforations, and so several can be combined to achieve desired length.

Figure 57: HydraArchimedes (HydraWell Intervention, 2015)

The resulting product should be a cement plug that has high bond quality and is hydraulically sealing in all directions, created with the majority of the casing intact and no swarf generated. The system provides a plug that can be verified in the annulus, unlike plugs that are set with the traditional section milling method. In this case, the plug is drilled out after it has set and a log is run to verify the bond in the annulus. In this scenario, a new cement plug has to be placed inside the casing with a new verification according to NORSOK standards afterwards (Ferg, et al., 2012). Data collected from HydraWell Intervention shows that 31 plugs has been logged from 2010 up to this date of May 2015. The data shows that every plug is approved, although six of them set in 2012/2013 shows sign if small issues (HydraWell Intervention, 2015).

8.1.2 The Tools & Operations for Double Casing

HydraWell has also developed a system to apply the PWC concept on multiple annuli. In a normal section milling operation with multiple annuli, the operation is doubled in the sense that the operation has to be performed for both casing separately. It goes without saying that the time consumption on perforating and washing behind double casings is immense, as it can be perceived from figure 58 where it is stated that the normal operation takes a minimum of 24 days versus a mere four days for HydraWell. It represents a time saving of over 83%.

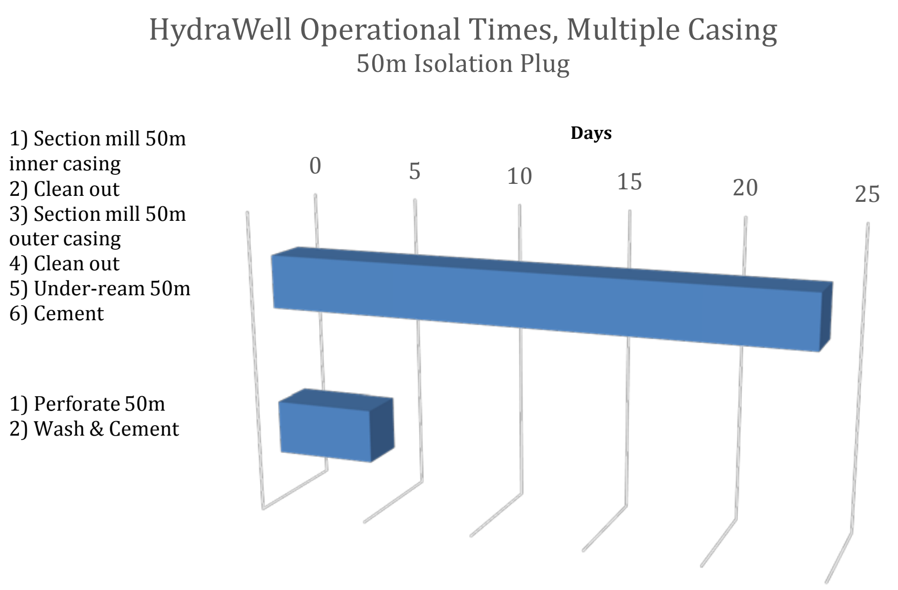


Figure 58: HydraWell Operational Times, Multiple Casing (HydraWell Intervention, 2015)

Although the systems for double casing shares design similarities with the HydraWash system, there are some vital differences. The system can be divided into three main steps: firstly, as the tool does not include a disconnecting plug, an EZSV is set to form a foundation. As this is completed, the HydraKratos and TCP gun can be run before the final washing is commenced using the HydraHemera.

8.1.2.1 HydraKratos

In cases where there is no annular cement in either of the annuli to hold the new cement plug, the HydraKratos is applied along with TCP guns. The TCP gun is run with the HydraKratos placed below it, and run to the pre-determined depth before a ball is dropped to activate the tool. As illustrated in figure 59, the TCP guns perform its normal job and perforate both casings with perforations as large and tightly spaced as both casing allows for. The energy from the HydraKratos is designed to be of such a magnitude that it expands both casings and form a casing-to-formation seal. This seal is what forms the base for the cement plug, also shown in figure 59. The tools are then POOH, and the HydraHemera can be RIH.
(HydraWell Intervention, 2015)

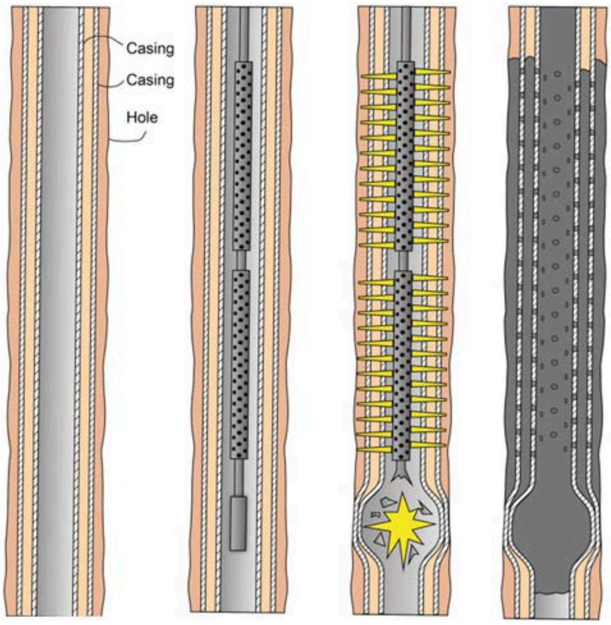


Figure 59: HydraKratos (HydraWell Intervention, 2015)

8.1.2.2 HydraHemera

The HydraHemera is the tool that makes it possible to wash behind dual casings, and consists of a bullnose with circulation, a jetting tool for washing and a cementing tool. As the tool is in position, a ball is dropped and makes it possible to achieve circulation through the jetting tool. It is important to note that the HydraHemera can also be used to wash behind a single casing.

The nozzles on the jetting tool are positioned at irregular angles and are engineered to achieve optimum configuration for washing at the optimal exit speed. The resulting jets will penetrate and clean behind the casings, as illustrated in figure 60. The washing process will start at the top, work its way down the perforations and then wash to the top again to ensure proper cleaning. (HydraWell Intervention, 2015)

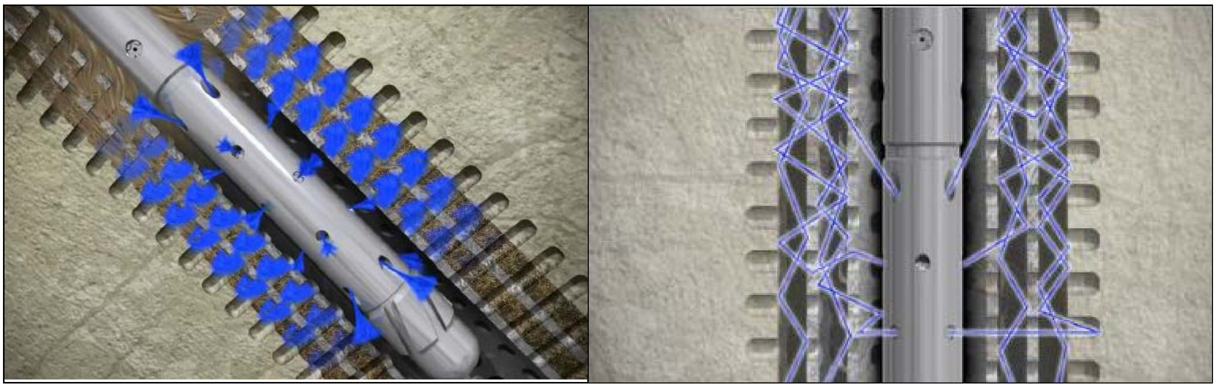


Figure 60: HydraHemera Animation (HydraWell Intervention, 2015)

Once the annuli are clean and the mud is displaced with a spacer fluid, a second ball is dropped which diverts the flow to the cementing tool, which features nozzles optimized for cement flow. Cement is pumped down and is pushed into the annuli via rotation of the tool and by utilizing the same HydraArchimedes tool that was discussed with relations to HydraWash. (HydraWell Intervention, 2015)

Figure 61: HydraHemera cementing (HydraWell Intervention, 2015)

Given that the operations is successful, the resulting product is a cement plug with high bond quality that is hydraulically sealing in all directions, inside the wellbore along with both annuli. Current logging technology has problems when faced with two annuli, and therefore cannot be used to verify the plug. Instead, positive and negative pressure tests are applied to make sure it holds NORSOK D-010 standards. Both short-term and long-term pressure tests can be performed, of 1800 psi for 24 hours or 1000 psi for 100 days, respectively (HydraWell Intervention, 2015).

8.1.3 Time & Costs

Given by table 12 are the track records from HydraWell's start-up in 2008 unto May 2015. A total of 107 HydraSystems has been installed, divided by 73 HydraWash and 34 HydraHemera. HydraWell reports that the tool success rate has been 99,4%, with a 97,5% system success rate (HydraWell Intervention, 2015). As the company becomes more experienced the products gets refined, which shows in the fact that the tool and systems success rate in 2014 was 100% and 99,7%, and with both being at 100% so far in May of 2015.

The price of each plug varies as a function of the number of plugs that are to be set, the number of wells and the geological location of the client itself. Even so, HydraWell estimates that it costs an average of one million NOK to set a plug, including the plug itself and personnel services from HydraWell (HydraWell Intervention, 2015).

It is estimated that the usage of HydraWell's PWC technology has so far saved the environment and crew from the exposure of 399 tons of swarf, and that 635 rig days has been saved (HydraWell Intervention, 2015). By the previous calculations of four million NOK/day, 635 rig days equals 2540 million NOK. In addition to this is the alternate cost of having the rigs drill wells or perform other interventions.

Table 12: Track records, HydraWell (as of 22.05.15) (HydraWell Intervention, 2015)

107 x HydraSystems	73 x HydraWash	34 x HydraHemera
2 ea. 2010	4 ea. 7"	3 ea. 7"x9-5/8"
17 ea. 2011	2 ea. 8-5/8"	3 ea. 8-5/8"x10-3/4"
31 ea. 2012	52 ea. 9-5/8"	2 ea. 9-5/8"x13-3/8"
17 ea. 2013	7 ea. 9-7/8"	1 ea. 7" CT
31 ea. 2014	5 ea. 10-3/4"	20 ea. 9-5/8"
9 ea. 2015	1 ea. 11-3/4"	2 ea. 10-3/4"
---	2 ea. 13-5/8"	3 ea. 10"

8.1.3.1 HydraWash

From figure 53 it is already stated that the HydraWash system can bring the time consumption of setting a plug from an estimated 10,5 days using section milling to just three days. To achieve the three-day option the operation needs to be performed in a single trip, but the operation can also be performed using two trips. In this case, the well is perforated in the first run before washed and cemented in the second – an operation taking around 4,5 days.

Table 13 represents a time breakdown of an operation conducted in 2013, where HydraWell contributed to plug a well via setting four plugs in the wellbore. Plug one and two were set using two trips, while three and four used just one each.
As it can be seen from the table, the setting of the four plugs took a total of 17,2 days to complete. Even so, the combined time the tools are actually in the hole is 287 hours (12 days).

Table 13: HydraWash: One well, four plugs (HydraWell Intervention, 2015)

		RIH		OOH		Time	Cum. Time	
Plug 1	TCP	03:00	23.07.13	00:00	23.07.13	21 hours	21 hours	0,9 days
	HydraWash	03:00	24.07.13	03:00	27.07.13	72 hours	96 hours	4,0 days
Plug 2	TCP	10:00	28.07.13	06:00	29.07.13	20 hours	137 hours	5,7 days
	HydraWash	10:00	29.07.13	01:00	01.08.13	63 hours	214 hours	8,9 days
Plug 3	HydraWash w/TCP	09:00	02.08.13	07:00	05.08.13	70 hours	316 hours	13,2 days
Plug 4	HydraWash w/TCP	15:00	07.08.13	09:00	09.08.13	41 hours	413 hours	**17,2 days**

Based on the operational info found in appendix A and appendix B, it can be seen that the time consumption used on the operations besides the installation of plugs is 7,57 days for well X-1 and 6,27 days for well X-2 – giving and average of 6,92 days. Assuming that this is a transferrable operational time for the well plugged in table 13, it gives a total operational time for the P&A of about 24 days. Also assuming the rate of four million NOK/day is transferrable with addition to the one million per plug from HydraWell, it comes out at a total cost of 100 million NOK. Compared to an average of 35 days, it amount to a saving of 40 million NOK just for one well, without taking into account the logistics, disposal and topside equipment that swarf generate.

8.1.3.2 HydraHemera

Under a normal section milling operation on multiple casings the under-reaming procedure is only necessary to perform once, but a section milling operation has to be performed for each casing. It is therefore clear that the time saving using PWC technology is much greater for double casings. The statement is already illustrated in figure 58, where the estimated 24 days for the milling of two casings can be brought down to just 4,5 days using PWC.

HydraWell reports that runs have been made setting a HydraHemera 7"x9-5/8" plug that, including WOC and testing of cement, took just 52 hours (2,17 days). This is a single run, while a TCP in a separate run would still take less than 3,5 days (HydraWell Intervention, 2015).

Another plug has been set in a in a similar time, a HydraHemera 9-5/8" was utilized in a single run, where it took 51 hours to set the plug including nine hours of mud rheology adjustments (HydraWell Intervention, 2015).

Figure 62 shows a time breakdown for the setting of a primary barrier using the HydraHemera system, giving a stronger picture as to what the operation entangles. The total time consumption of 5,46 days is including 5,75 hours of non-productive time (NPT).

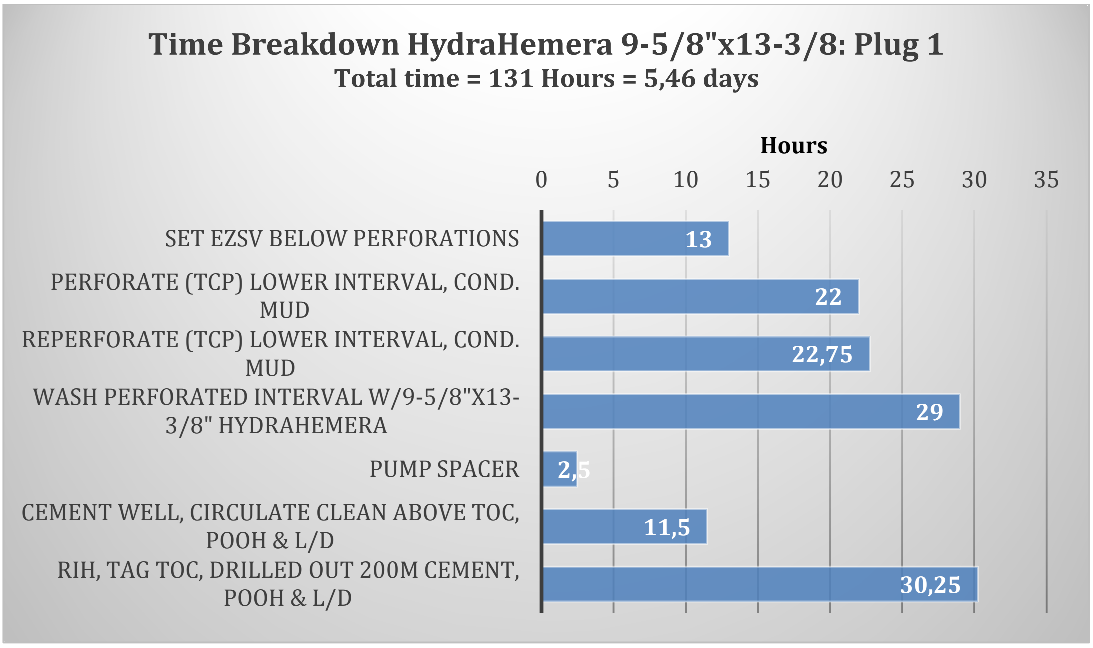


Figure 62: HydraHemera time breakdown Plug 1(HydraWell Intervention, 2015)

Unlike the HydraWash system, the HydraHemera system does not entangle its on bridge plug, and as a result 13 hours are spent setting an EZSV in a separate run. Still, confining the time consumption from the setting of the bridge plug to the wellbore is ready for the plug it takes just 76,25 hours (3,2 days).

Figure 63 represents the setting of the second plug, and here there are 3,5 hours of NPT included in the 3,89 days of time consumption. As perceived, getting the wellbore ready to set the plug takes a total of 64,5 hours (2,7 days).

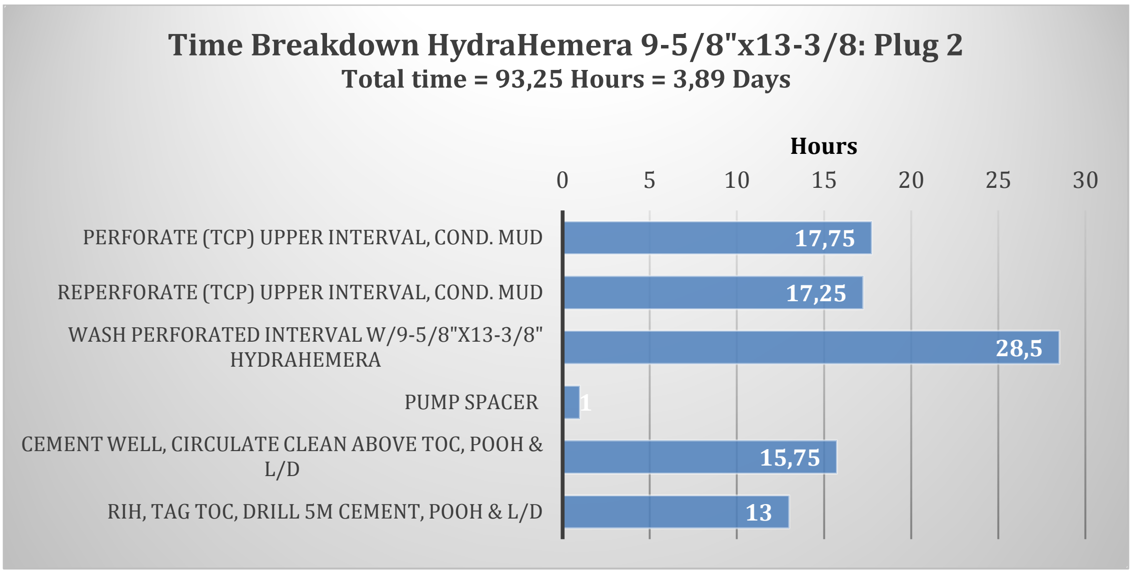


Figure 63: HydraHemera time breakdown Plug 2(HydraWell Intervention, 2015)

8.2 Upward Section Milling

During the discussion on section milling it was stated that the operation is normally done in a downward fashion by applying weight on the mill itself.

Another concept is to mill upwards, which is made possible by using tension to drag the mill up, instead of weight pushing down. This will, of course, relieve all need for heavy tubular equipment, but the biggest advantage of milling upward is that the swarf is left downhole. As discussed in section 7.3.2, swarf is an enormous problem during section milling – and the many of the main issues that section milling develop can be lead back to swarf. Leaving the swarf downhole means that the circulation does not need to transfer it to the topside, illustrated in figure 64. This will in turn mean that there is no need for topside handling and disposal, which also means that HSE is improved and that the BOP is kept free from the damaging swarf.

Figure 64: Reverse section milling (West Group)

Perhaps more important for efficiency, it means that the special milling fluids are deemed unnecessary, and that the crew can mill as fast as possible without having to worry about ECD versus proper transport.

The concept and method of reversing the section milling operation is described in a patent from the United States released back in 2004 (Davis & Lynde).
The method presented in the patent gives two options with regards to the apparatus: either with a mud motor or with a single rotating work string, illustrated in figure 65.

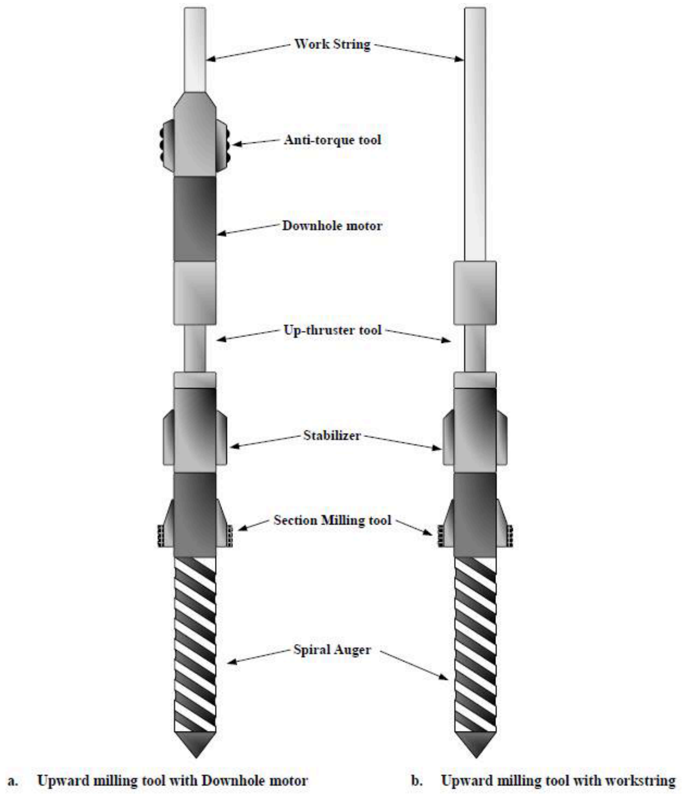


Figure 65: Upward Mill Assemblies (Toro, 2013)

8.2.1 The Method

Just like with section milling the tool is RIH to the desired depth where the window is to be cut. If a downhole motor is employed to provide rotation, it is also entangled with an anti-torque tool that is there to stop the drill string being affected by the generated torque from the motor. It was found that without this option the torque when the motor stalled could twist the drillstring to such an extent that it shrunk in length, causing the blades to quickly degrade (Davis & Lynde).

The anti-torque tool is set against the casing by use of a hydraulic pressure to exert the force on the gripping mechanism. Although this mechanism prevents any rotary action of the tool itself, it is described as being able to still move in a longitudinal direction by employing one or several wheels (Davis & Lynde).

The constant upward force needed to mill is provided with the up-thruster, as it is found that the force from the rig itself would be too irregular to be used for this intent. The operator would have to be extremely careful not to overload the mill, or the motor would stall (Davis & Lynde).

The up-thruster is described as a hydraulic cylinder that is pressurized by the mud being pumped via a fluid flow path in the anti-torque tool. At the bottom of the milling assembly there is a restriction nozzle creating backpressure and thus forcing the mechanism up, see item #3 in figure 66. With a lifting cylinder, the pump pressure can be controlled to such an extent that the loadings on the mill remain very constant.

As the tool is RIH, the piston and mandrels form an annular hydraulic cylinder being held by a shear pin. Once enough backpressure is applied this pin is designed to break and thus inner piston and mandrels moves upwards.

To provide stability during the operation, the stabilizers above the section mill extend several blades relative to the casing. The blades extend at a fluid pressure lower than the pressure needed to run the up-thruster, to provide stability throughout the operation (Davis & Lynde).

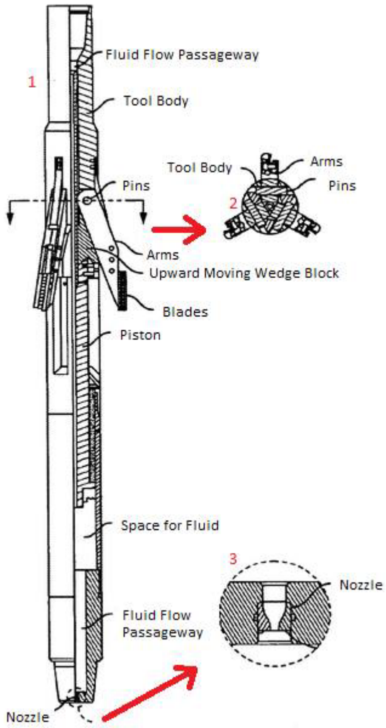


Figure 66: Upward Section Mill Tool (Davis & Lynde)

The arms and cutting mechanism work in a similar way as with conventional section milling. Application of fluid pressure below the piston in figure 66 exert an upward hydraulic force that moves the piston itself and the wedge block up towards the arms and extends them. In order to retract them, a ball can be dropped against the piston that sends it back down.

The final component of the tool is a spiral auger, positioned below the section mill. This is simply a short drill collar dressed with left hand spiral twists, and the concept is that as it rotates it will force the cuttings to the bottom of the well and away from the tool, preventing bird nests around the mill (Davis & Lynde).

8.2.2 SwarfPak & Time Consumption

A company named West Group from Stavanger, Norway, has created a more modern take on the reverse section milling called SwarfPak. The assembly is more compact than the one suggested in the patent from 2004, and consist of the milling tool along with slips and screens with stabilizers (West Group). It introduces reverse flow principles, like in gravel pack, to deposit the swarf downhole.

West Group lists the following as the benefits of using their tool compared to conventional section milling:

- Precise and ultra fast milling speed
- Upwards milling leaves swarf downhole
- Increased safety – no swarf in BOP
- Eliminates swarf handling on surface
- Eliminates vibrations

(West Group)

Figure 67: SwarfPak (West Group)

West Group reports that the typical parameters with the SwarfPak are a milling speed of 30 m/hr. with a rotational speed of 80-100 RPM (West Group). This milling speed amounts to over 98 ft./hr., and would be an enormous development over conventional section milling. However, West Group has not provided any detailed operational data to this thesis in order to verify this number.

It is furthermore reported in West Group's website and in SPE journal paper #0514-0086 that the typical milling speed is three to six times faster than conventional milling (West Group) (OTC, 2014). By applying the actual performed operations of the wells X-1 and X-2 that was previously discussed, it can be found that the average actual milling speed of the four different operations was 5,25 ft./hr.

Given these parameters and statements, it can be assumed that the actual milling speed of the SwarfPak amounts to between 15,75 – 31,5 ft./hr.

8.3 Melting

There is a concept to melt away the tubing and casing instead of pulling or milling it. Conversations with the Norwegian industry confirm that a project where plasma is employed in the wellbore is applicable, but it is not revealed more than that the technology is based upon creating plasma in the wellbore to use it as a fundament or a possible barrier element (Edholm, 2015).

GA Drilling A.S. is a company out of Bratislava that has made such a system, and its rapid material degradation can be used for both cost-efficient drilling in rock and to melt casing. The tool is called PLASMABIT, and is illustrated in figure 68. This differs from every concept seen so far as it is a non-contact tool run on coiled tubing from and is therefore also rig-less.

Figure 68: PLASMABIT by GA Drilling (GA Drilling, 2015)

Instead of physical contact, the tool uses a thermal heat-flow plasma generator that is optimized for thermal rock or steel processing. This generates much smaller particles than with section milling, and it can be removed from the annulus while not making any restrictions with regards to the BOP. The generated heat-flow comes from an electrical arc that rotates at 800 revolutions per second for melting. This will effectively melt, evaporate and fragment rock, steel, cement or any other material (GA Drilling, 2015).

By applying this tool, GA Drilling reports the following crucial benefits:

- Save time and cost through rapid steel degradation in one run
- Achieve efficient constant speed of steel/cement milling
- Generate metallic powder instead of undesirable swarf
- No plugged annulus and BOP with steel cuttings
- High reliability of the tool due to non-contact approach

(GA Drilling, 2015)

The testing of the milling tool is relatively new, with operations in water environment and high pressure vessel testing both passed early in 2015 (GA Drilling, 2015). As a result, there are no available field data to this thesis, and performance figures becomes very hard to predict. However, it is estimated by GA Drilling that the time consumption compared with a conventional milling operation is of 30% (GA Drilling, 2015).

Figure 69: PLASMABIT Milling(GA Drilling, 2015)

8.4 Alternative Concepts

The following additional alternative concepts are technology that has not been found at vendors on the NCS, but nevertheless constitutes an interesting idea for replacing or improving conventional section milling.

8.4.1 Crushing

Although this concept primarily concerns the removal of tubing, it would be very interesting to develop it further to deal with cemented casings in addition. The rig-less abandonment concept is based on the patents visualized in figure 70, where the tubing is compressed to an extent as to provide a window where a log can assess the cement behind the casing. In this way, the tubing does not need to be pulled, saving time and removing need for heavy lifting. The equipment is run on wireline and without a marine riser.

The forces needed to crush the casing is described as significant, but a tubing with damage or excessive wear would decrease the required force. In addition, a vertical cutter can weaken the tubing ahead of the operation. (Oilfield Innovations, 2012)

The method involves the following:

- Cutting tubing
- Placing a piston
- Crushing the tubing to make space
- CBL log within the space
- Repair leaks by squeezing cement behind the casing through perforations and/or placing a cement abandonment plug using the remaining tubing and annuli to seal hydrocarbons below the cap rock

(Oilfield Innovations, 2012)

As perceived by Figure 70, the a cement retainer umbrella is used as a piston with frac sand, glass beads and other gradated material, viscous fluids and inflatable packers to provide a piston seal above which a heavy mud may be placed to increase the pressure applied for the piston crushing (Oilfield Innovations, 2012).

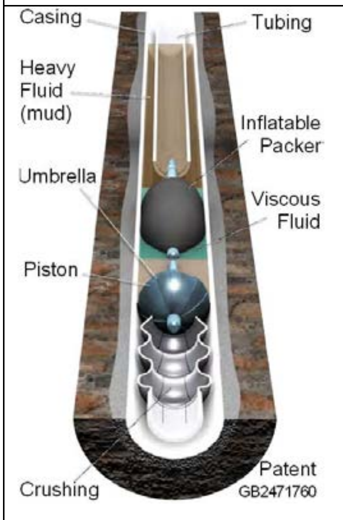
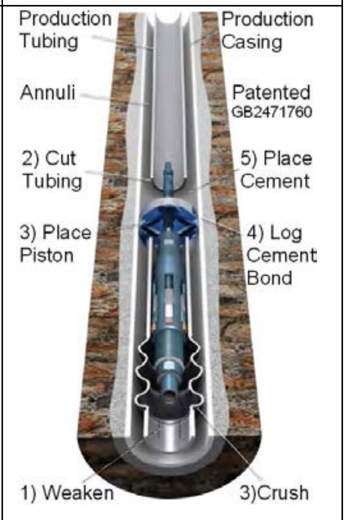
Cement Retainer	Rig-less Abandonment Method
	

Figure 70: Crushing tubing concept(Oilfield Innovations, 2012)

8.4.2 Chemical Degradation

Erosion and corrosion has already been mentioned as factors with regards to amount of swarf generation. Many old completions on the NCS have tubing and casings that are beginning to get severe degradation due to chemical corrosion. A rig-less concept to remove the metal of the wellbore is to accelerate the chemical degradation by pumping continuous a flow of strongly corrosive chemicals into the wellbore. This would ensure that no swarf is generated along with any need for handling of tubing/casing topside. In such a case, a barrier with a resistance coating has to be placed to limit the chemical's depth and ensure the rest of the wellbore is not degraded in addition to the tubular. Such a concept is also applicable to conventional section milling, where the structural weakening of the casing could improve the performance of the milling operation.

However, risks can be defined as the storing and handling of strongly corrosive chemicals, along with a risk of corrosion on other vital equipment of same structural material as the casing or tubing.

9 Discussion

9.1 With relations to P&A fundamentals

The Norwegian petroleum industry is young, and so there has not been a need for P&A on a large scale on the NCS. As a result of this lack of attention to the P&A market there are small amounts of available information and statistics on it. However, as a result of major fields reaching the end of their productive life, along with stricter regulations, there is now an increase in focus on the P&A challenge. It is stated in this thesis that with current technology and 15 rigs working fulltime, it would take around 20 years to PP&A the wells of today, and another 20 years to PP&A the wells that has been drilled during this time. The bill could be as much as 900 billion NOK, divided 22% by the operator and 78% by the government.

The P&A industry is technological underdeveloped compared to many other regions of the petroleum industry. It brings no financial upside, and for wells that pre-date 2014 there was no regulatory requirements for when to PP&A a well. As a result, many operators have had a tendency to put off the PP&A and choose a temporary abandonment often on a prolonged schedule. Analysis done by the PSA shows the result of this, with published information saying that 29% of 119 subsea wells and another 59% of 163 platform wells that were temporary abandoned on the NCS in 2014 had a status with degraded barriers or worse.

It would seem that the operators are waiting for a technological leap that revolutionizes the PP&A in such an extent as to make it a lot more cost-efficient. However, because the contract offerings from the service companies today are not meeting operator expectations, small amounts of revenue are being spent and therefore these technological developments are also being obstructed. All in all it creates a vicious circle, presented in figure 71.

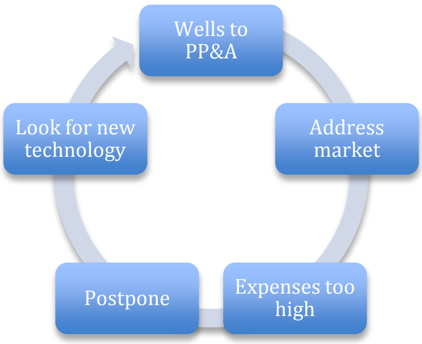


Figure 71: PP&A operation circle

On the other side of it, ConocoPhillips has expressed concern about the efforts of the three big service companies Halliburton, Schlumberger and Baker Hughes in this case. A quote from ConocoPhillips' decommissioning manager Tim Croucher says that they have reached out to the service companies and asked to consider solutions, but were extremely disappointed with the level of interest and feedback they got (DecomWorld, 2015).

Nevertheless, while the temporary abandonment period are extending, the well conditions are deteriorating. As a result, the PP&A is getting more demanding (e.g. collapsed casing) and therefore more expensive.

Today's industry is characterized with significant cost savings, due to a sudden drop of the oil price along with operators trying to become more cost-efficient. A presentation held by Espen Norheim under a rig conference in Stavanger 2015 shows that the revenue growth of the Norwegian offshore industry in 2014 was 4%, and that the projected number of 2015 is a decline of 7%. On global E&P, analysts' forecasts cuts in capital expenditure by 20-25% from 2014 to 2015 (Norheim, 2015). The result of this is that rig rates along with personnel and equipment rates are significantly reduced. In fact, a rig contract procured by Rowan in May 2015 shows that their rig rate has declined with 38%, taking effect from 01.01.2015 (Offshore.no, 2015). It is stated that the move from rig-based PP&A to dedicated, smaller vessels would decrease the costs and increase production, but given the decrease in rig-rate it is an opportunity that must be seized. Transocean alone are reporting that 63% of their floating rigs will be available for missions before the end of 2016 (Bjørsvik, 2015).

Given the circumstances of increased costs of not doing anything along with the reduced rates on the NCS, it would seem that current economic situation is a good foundation for the P&A industry to grow on. The oil price will most likely increase over time along with costs and rig rates, while the wells are legally required to be PP&A. As a result, there is no better time than the present.

9.2 With relations to well barriers and regulatory framework

It is discussed previously in the thesis that modern oil and gas drilling as it is perceived began in Pennsylvania in 1859. At that time the environmental challenges were not an issue, and the safety implications of incorrectly abandoning wells had not been established. As a result many wells was not plugged at all, and when regulations were written they were so vague that wells would be plugged with everything from brush, rocks and wood to linen sacks. These acts has led to the result of a study in 2014, where it was found that a substantial number of the 300 000 – 500 000 wells of Pennsylvania could be leaking quite significant quantities of methane (Vaidyanathan, 2014). The greenhouse gas methane is recognized as being 86 times as bad for the climate as CO_2 on a 20-year time scale. Of the 19 wells that the scientists studied, only five of them were plugged. It was furthermore found that both plugged and unplugged wells were leaking, and calculations showed that it could have contributed to as much as 4-7% of the emissions recorded in Pennsylvania in 2010.

The Norwegian industry, being much younger, has had a regulatory system long before the P&A operations commenced. The regulatory systems have been presented in this thesis, and it has been shown that the NORSOK standard D-010 – Well Integrity in Drilling & Well Operations is of primary interest for P&A operations.

The NORSOK is an initiative meant to add value, reduce cost and lead-time and to eliminate unnecessary activities in offshore field developments and operations. However, with the release of revision three of D-010 in august 2004 came a sudden increase in the duration of a PP&A operation. The average operation increased from 16 days to 35 days, an average which still applies today. Even though it is not specifically documented, it is assumed that rev.3 is an important part of this increase.

Although there are different acceptance criteria's for different placements with regards to barriers and safety, NORSOK specifies the following for a PP&A:

"Permanently abandoned wells shall be plugged with an eternal perspective"

(NORSOK D-010 Rev.4, 2013)

Eternity is a long time, and to some extent the quote becomes somewhat irrational. Nothing lasts forever, and how the casing and plugging material will deteriorate over hundreds of thousands of years is difficult to predict. The lithosphere is in constant movement, and at some point the very soil we stand on will be part of the asthenosphere and the PP&A method employed will be insignificant.

Oil & Gas UK has a different approach to the same challenge:

"The objective of P&A is to restore the integrity of the cap rock"

(Oil & Gas UK, 2012)

Given that NORSOK and Oil & Gas UK are both initiatives that revolve around the same type of environment, they should be comparable to each other. However, while NORSOK suggests that a plug shall be 100 m MD for an open hole section, Oil & Gas UK suggests 100 ft. MD (30,48 m). Approximately three times the length is a substantial difference, and it raises the question if the NORSOK initiative has defined "good enough" to be excessive. This is a question that is problematic to answer, as there is no requirements to monitor the wells that has been permanently abandoned. That means that although the wells are plugged with the assumption that a 100 m long plug is enough, there are no scientific studies available to this thesis that shows if is a factual statement. Because the industry are actively searching to significantly reduce the average duration of the P&A operation, it is the author's opinion that a scientific evaluation of the quality of the plugging should be performed in order to see if it is being done excessively thorough, or worse, not good enough.

Because the different parties of the global industry are all working under their own assumptions of "good enough", it would seem that a global initiative with scientific data suggesting what quality is actually sufficient would be in everyone's best interest. Given the current economic situation, it would also be interesting to customize the required barrier length by downhole conditions and barrier material utilized. However, such an initiative could very well present itself as too complicated to comply with so many participants, different cultures and practices.

9.3 Summary of section milling investigation

To address the current P&A situation of a long average operational time, the scope of this thesis included an investigation into the section milling operation. It was established that the successful placement of a permanent plug is measured according to the effective bridge that is formed across the wellbore and seal both vertically and horizontally. Section milling is a technology usually required when the placement of this plug is not possible due to a stuck casing or poor cement job behind the casing. Due to the status of being an operation only performed when it is absolutely necessary, an investigation was performed in order to map the technology's challenges and improvement potential.

The investigation involved the plugging of two wells on the NCS. An operator that for all intent and purposes wishes to remain anonymous provided the full operational reports to this thesis. As a result, the wells are only referred to as well "X-1" and well "X-2".

Section milling is generally known as an operation that is time consuming. Figure 72 is a visual representation of the operational times of the P&A of the wells X-1 and X-2.

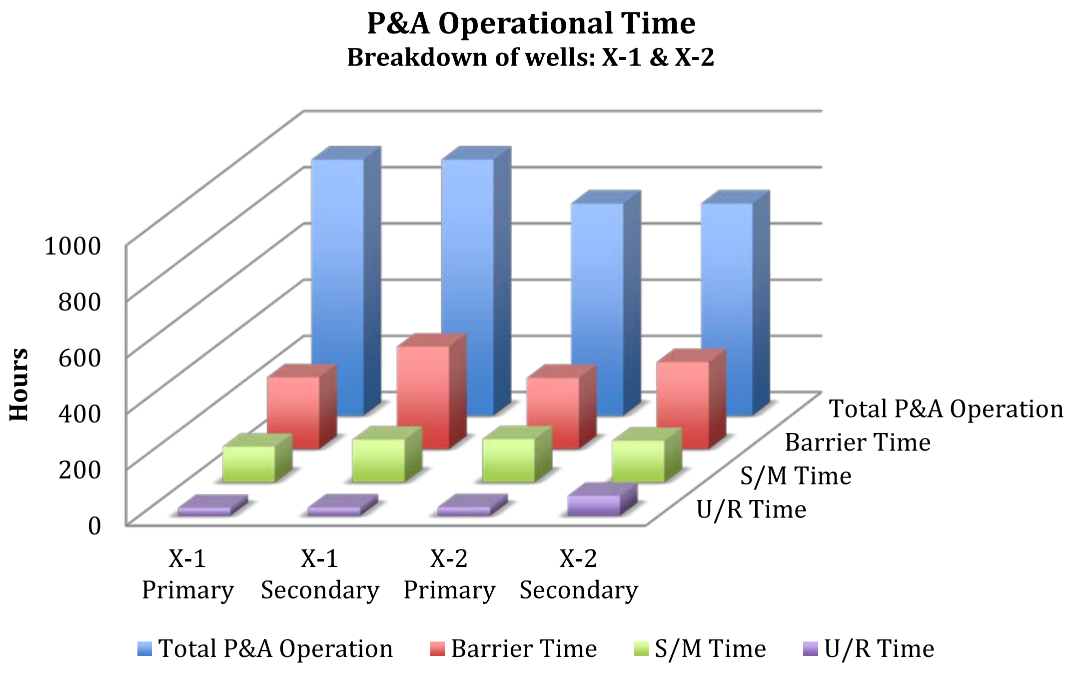


Figure 72: P&A Operational Time, X-1 & X-2

The investigation into the operational reports showed that during the P&A operations, installation of the barriers was the most time-consuming. A total of 61% of the time was spent on these installations on X-1, while 75% was spent on the same for X-2.

The total P&A operation on X-1 took 37,93 days. A detailed breakdown of the operations included in the installation of the primary barrier showed that the section milling and under-reaming was the most challenging part of the installation. The installation of the primary barrier took 10,66 days, of these days the section milling was responsible for 50% (5,33 days) and the under-reaming for another 11% (1,17 days).

The operations report was consulted in order to find the causes, and it was discovered that pack-off tendencies were a major issue due to insufficient swarf transport. It caused several delays during the operation, and eventually lead to loss of 71,08 ft. of the BHA which in turn launched a 33 hour long fishing operation. When the section milling was running, it had an average ROP of 6,2 ft./hr.

The installation of the secondary barrier on X-1 took 15,21 days. Once again the section milling and under-reaming was the most challenging part, taking 42% (6,39 days) and 8% (1,22 days) respectively. The investigation showed that although pack-off was present, it was not as big of an issue on the secondary barrier. However, the taper mill was broken off downhole on two separate occasions. While one was pushed out of harm’s way, the other one jammed and led to an extensive operation where a cement plug was set and then drilled out in order to achieve a foundation for the permanent plug to be placed on. Even so, the more efficient swarf transport gave a slightly higher average ROP at 6,6 ft./hr.

The total time consumption for the P&A of well X-2 was 30,17 days. The exact same trends were showed on this well, in that the section milling and under-reaming was by far the most challenging aspect of the barrier installations.

The installation of the primary barrier took 10,57 days. Of these days, section milling represented 61% (6,45 days) and under-reaming another 12% (1,27 days). The investigation showed that the problems encountered was once more due to pack-off, which on several occasions jammed the pipe. Because of the transport problem, the average ROP for the section milling was only 2,8 ft./hr.

The installation of the secondary barrier took 12,93 days. The section milling was responsible for 48% (6,21 days) of the time consumption, and the under-reaming for another 23% (2,97 days). It was found that there had been concerns about the ECD during the operation which lead to some delays, but the section milling went without too much challenges and ended up at an average ROP of 5,4 ft./hr.

9.4 With relations to the section milling technology

During the investigation of the section milling technology and procedures, several challenges was encountered. Amongst these were violent vibrations, difficulties verifying the plug and the pure waste of time during tripping operations. However, there seems to be one that rises above all of these: swarf generation and the handling of it.

During the investigated wells X-1 and X-2 there was several problems encountered, but the one that was similar for all operations was the pack-off tendencies. The pack-off is a direct result of poor swarf transport, as it collects around the drillstring and jams it. In the cases investigated the main limiting factors of the section milling operation led back to swarf.

It has been presented in this thesis that a typical 50-meter section of a 9 5/8" casing can generate four tons of swarf. Furthermore it is estimated that some operators only manage to recover topside 25% of the swarf that are generated, and that 55-70% can be recovered with the proper parameters. Insufficient removal of the swarf can ruin the sealing capabilities of the permanent plug and damage critical equipment like the BOP, and for these reasons it needs to be removed as thoroughly as possible.

Two main factors of the millings efficiency have been found during this thesis, the first being the milling fluid. The milling fluid is the medium that transports the swarf to the top, and the proper transport will often be a limiting factor of these operations. Given the amount of swarf that needs to be transported, it has been presented that an optimal situation is where ROP, flow, pump pressure and viscosity are all working together to form a "sweet spot" where the transport is good but the ECD is not sufficient to fracture the exposed formation.

Although there are several advanced fluids available for this purpose, it is found that the more simple water-based KCl polymer mud is often the best choice. This comes not only as a result of price, but because they are easy to manipulate with regards to viscosity and can handle large amount of contamination from the old mud behind the casing without loosing essential characteristics.

OBM's are rarely used as milling fluid but can be employed in situations where the milling section is very short and/or with delicate ECD limits. It is also gentler with regards to corrosion than and not as sensitive to gas-cut as WBM.

The second factor of the efficiency was found to be the cutters of the mill itself. Historical improvement of the cutter technology was presented along with an improvement campaign by joint venture of ConocoPhillips and Baker Hughes. It was seen that the implementation of new cutter technology saved considerable time by cutting average number of trips from 4,22 in 2004 to just 1,5 trips in 2010, while exhibiting high levels of impact resistance and an increased ROP. The chemistry and geometry of the cutters was the main contributors to this advancement and is still vital for continuous timesaving.

Today's cutters are made by pressing tungsten carbide powder into a mould to create a particular shape, which can be specified to basically anything. The most important aspect of the design, however, was described as being the chip breaker. The chip breaker is designed to reduce the effective length of the cuttings to around one inch in length to avoid generation of bird nests while still having enough surface area for effective transportation.

The section milling has been described as a technology only employed when it is absolutely necessary, and comes as a result of the challenges presented and discussed in this thesis. However, due to the lack of a technology that can replace it in every way, it is still a technology that has to persist for now. As a result, the technology has to be refined to ensure the optimal performance.

The current economic status of the Norwegian petroleum industry is making operators actively search for stability and predictability in their investments. These are not preliminary characteristics that define section milling today. Still, it is estimated that an optimal section milling operation could have the potential to perform with an ROP 20-40 ft./hr. An optimal solution could be to refine the technology to an extent where it can run smoothly and predictably at 20 ft./hr. It is in the author's opinion that considerable time could also be saved by developing a tool that could perform the entire operation in a single run. This tool would incorporate a mill tool with multiple sets of blades, the under-reamer, a cement stinger and EZSV all in one assembly. This would ensure a more cost-efficient operation, while still maintaining the relative simplicity and effectiveness of the section milling operation with regards to the placement of the permanent barrier.

9.5 With relations to PWC technology

The PWC has been presented as perhaps the most applicable alternative to section milling because of its multiple advantages. Because the casing is perforated rather than milled, it leaves the casing intact, which means that it does not create any swarf. It is estimated that the usage of HydraWell's PWC technology alone has saved 399 tons of swarf generation from 2008 to May of 2015. As no swarf is generated, many of the previously discussed issues disappear. These include the need for special milling fluids, HSE issues, BOP damage, and pack-off tendencies. It also brings environmental advantages of not needing to dispose of the swarf and the logistics it entails. Leaving the casing intact furthermore means that re-entry is possible at a later point in time, and that tripping time is saved because there is no need to pull bits of casing.

One of the main advantages of the PWC technology was described as the reduction in rig time and thereby costs. Track records from HydraWell showed that their system had been used to set 107 plugs so far, with a tool success rate of 99,4% and a system success rate of 97,5%. The estimated timesaving of this versus traditional section milling was a total of 635 days.

Numbers provided by HydraWell showed that in operations with a single casing, the average section milling was done in four separate trips and took 10,5 days. By comparison a PWC operation could be done using just one trip, taking three days and reducing the time consumption by 71%. Investigation into actual track records confirmed these numbers, where two plugs were set using two trips taking an average of 4,46 days and two plugs were set using one trip, taking an average of just 2,13 days.
Cases where the PWC technology was utilized on multiple casings were also presented. Because the section milling technology only tackles one casing at a time, this is an operation that takes an estimated minimum of 24 days. By comparison, a PWC operation on multiple annuli can be performed in just 4,5 days, making it a timesaving measure of 83%. Investigation into operation reports confirmed also these numbers.

So far, everything looks promising, but there are issues – one of them being plug verification. As previously discussed, NORSOK recommends that each plug shall be tested to verify it. A cement plug set with section milling will cover the entire cross-section of the well, but with the PWC technology there are also cement in the annulus. This means that the cement needs to bond with the casing in addition to the formation.

The plug set over one annulus can be verified by logging, in such a case the plug is drilled out to give way for the logging assembly and then cemented again. However, modern logging technology has severe difficulties logging through several casings. As a result, the same pressure tests and tagging that is performed with normal section milling applies. However, because there are two annuli there can be issues where the inner annulus is sealing off the wellbore, but the outer annulus cementing is of poor quality causing leaks.

Conversations with the industry have also expressed concerns about the ability to properly clean in operations with multiple annuli. It would seem that the belief is that the PWC technology is not refined to an extent where it is trusted to clean properly behind the outer casing. This is basically the main issue, because this distrust means that the plug verification is essential for the technology to sustain.

It is in these cases where the section milling still has to be employed, and so to remove the inner casing in order to use PWC on the outer. Section milling is also used if logging shows that the washing behind the single casing operation was not of adequately performed, and it shows that although PWC is recognized to be the primary option of the alternatives, it is not yet ready to fully replace section milling.

9.6 With relations to upward section milling

Upward section milling was described as a possible alternative to conventional section milling. Instead of using weight to force the mill down, this method employs tension to drag the mill up. The main benefit of this is similar to PWC in that swarf transport is eliminated. Instead of transporting it to surface, the swarf gets deposited downhole. This means that high-viscosity milling fluids are not required, and that HSE and BOP issues are eliminated in addition.

Because the transport of swarf is removed from the equation, the limiting factor of transport versus ECD is no longer an issue. A tool developed from WestGroup was presented, with a following statement that typical parameters was an ROP of 98 ft./hr. at 80-100 RPM, however it was not possible to confirm these numbers with WestGroup. Several sources have another claimed performance number, which say that the performance is three to six times greater than that of conventional section milling. By applying the average 5,25 ft./hr. of the wells X-1 and X-2, this gives an estimate of 15,75-31,5 ft./hr. It is important to note that these numbers are not by any means confirmed, but solely included to give a picture of the improvement potential by using available information.

Although being an exciting concept, there are some concerns with the upward milling technology. First and foremost, conversations with the industry express a great concern about the feasibility of managing a constant, upward force in order to avoid irregular pull and to destroy the mill.

The biggest concern is with regards to the setting of the cement plug. It has been presented in this thesis that one of the reasons swarf is removed is because it can interfere with the cementing operation and give poor sealing capabilities of the barrier element. In upward section milling, all the swarf are left downhole where the cement plug is supposed to be set. In addition, the technology does not involve under-reaming to expose fresh formation and remove contamination. These are challenges that the author did not find adequate literature on how to conquer. A development past these issues could imply that the upward section milling could replace conventional section milling where the PWC technology is inadequate, and so to make it an optimum choice before PWC is perfected.

9.7 With relations to concepts

Of the technology concepts without current vendors on the NCS, three concepts were presented. These were the crushing of tubing, chemical degradation and melting. It is in the author's opinion that the melting of tubulars is the most promising technology out of these options. It is revolutionizing in the sense of being a non-contact tool, and has the potential to simplify the entire P&A process. In addition, it serves the goal of moving to dedicated vessels and therefore saving time and expenses. Several companies are looking into this, but on the NCS the technology is still a few years away (DecomWorld, 2015).

The crushing of tubing is described as a process in need of significant force to succeed, but it is also mentioned that any wear or damage to the tubing could decrease the required energy. In this sense, a joint venture between the chemical degradation to accelerate the corrosion and the subsequently crushing could be a viable concept in the future. It is also possible that the application of chemicals could also have a future in the sense of accelerating the rate of which certain formations creeps, in order to manipulate a shale annular barrier.

9.8 Summary of methods

The following table gives a brief summary of the technologies and alternatives that has been discussed in this thesis, with regards to both positive and negative characteristics.

Table 14: Summary of alternatives

Method	Positive	Negative
Section Milling	• Field proven method • Still the method of last resort • Has potential with development of new tool assemblies	• Time consuming and expensive • Swarf generation and transport • Needs high-viscosity milling fluid • HSE & topside equipment • Tripping time • Violent vibrations • Plug verification • Pack-off tendencies
PWC	• No swarf generation • No need for topside handling of swarf or tubular, HSE • Verified time and cost savings over conventional S/M • BOP safety • No need for high-viscosity milling fluid • Strongly reduced pack-off tendencies • Possible re-entry	• Plug verification can be challenging • Modern logging technology struggles to log multiple annuli • Challenging to clean sufficiently with multiple annuli
Upward Section Milling	• No transport of swarf • No need for topside handling of swarf or tubular, HSE • BOP safety • No need for high-viscosity milling fluid • Higher ROP than S/M • Eliminates vibrations	• Performance parameters are not confirmed • Can be challenging to retain a constant, upward pull • The swarf left downhole will be implemented in the cement plugs and can cause leaks
Melting	• Saves time over S/M (estimated) • No swarf • Can be performed in one run • Non-contact tool, reliability • No tubing handling at surface, HSE • Rig-less concept • BOP Safety	• No available literature on field tests • Power supply
Chemical Degradation	• No swarf • No tubing handling at surface, HSE • Rig-less concept • Required chemicals exist • Limited mechanical operation, reliability	• No available literature on field tests • Need continuous flow of fresh chemicals • Can be time consuming
Crushing Tubing/Casing	• No swarf • No tubing/casing handling at surface, HSE • Rig-less concept	• No available literature on field tests • So far only a concept for tubing removal • Substantial force required

10 Conclusions

It was the scope of this thesis to provide an investigation into the P&A industry with a particular attention to the section milling technology and possible improvement potential.

With the cultivating attention to the PP&A challenge on the NCS, goals has been set to significantly reduce the average PP&A operation's duration and costs. The successful placement of an abandonment plug is measured according to the effective bridge that is formed across the wellbore section and is sealing in all directions. It has been shown that to achieve this, 47% of the time consumption is spent removing casing.

In cases where the casing cementing is poor or the casing is stuck, a section milling procedure has traditionally been the solution. The technology comes with major challenges, the principal ones being time and costs in addition to swarf generation and handling. Investigation into operation reports revealed that the placement of barriers were by far the most time consuming part of the PP&A operation, taking of 68% of the investigated average 34,05 days duration. For the placement of barriers, section milling and under-reaming was responsible for an average of 67% of the time consumption on primary barriers, and another 61% for the placement of the secondary barriers.

The most important factors for performance improvement have been presented to be the cutters of the mill and the milling fluid, as the investigation showed that pack-off tendencies due to swarf was the main disadvantage for performance, causing it to run at an average 5,25 ft./hr. Milling has the potential to run at 20-40 ft./hr., and further improvement could be achieved by developing a multi-purpose tool with a high, stable performance and reduced tripping time by implementing several tools into one assembly.

To this day, no available technology can fully replace the section milling solution. Even so, several technologies present good options. Amongst these, PWC has been presented as the most field proven technology that at the same time reduces rig-time by up to 83%. It also eliminates the swarf problem by perforating the casing and washing behind it rather than to mill. However, challenges still need to be overcome with regards to plug verification and washing performance particularly with multiple annuli. Amongst concepts without field tests on the NCS, the material degradation by using a thermal heat-flow was found to be the most promising technology, with an estimated 30% time reduction compared to conventional section milling and using a non-contact tool.

In order to meet a challenge with the magnitude of PP&A on the NCS, operators and service companies needs to work together to design and front cost-efficient solutions to a technological underdeveloped part of the petroleum industry. At the same time, current standards needs to be developed simultaneously to ensure that the PP&A of petroleum wells on the NCS is done both sufficiently secure but also cost-efficient compared to the current standard.

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Appendices

Appendix A

ID		Orig ID	Task Name	Predecess	% Complet	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth	Orig Depth
0		0	Plug & Abandonment [redacted]		99%	910,25 hrs	37,93	04.01.10 01:45	11.02.10 00:00	10072	10072	10072
1	✓	1			100%	2,25 hrs	0,09	04.01.10 01:45	04.01.10 04:00	10072	10072	10072
3	✓	3	Rig up on Well [redacted]	1	100%	9,25 hrs	0,39	04.01.10 04:00	04.01.10 13:15	10072	10072	10072
9	✓	9	Pull DHSV	3	100%	1,5 hrs	0,06	04.01.10 13:15	04.01.10 14:45	10072	10072	10072
12	✓	12	Cut Tubing and Kill Well	9	100%	47,5 hrs	1,98	04.01.10 14:45	06.01.10 14:15	10072	10072	10072
23		21	Contingency: Tubing punch and cut with Radial Cutting Tool (RCT)	12	0%	0 hrs	0	06.01.10 14:15	06.01.10 14:15	10036	10036	10036
32	✓	30	Nipple Down X-mas Tree	23	100%	6,5 hrs	0,27	06.01.10 14:15	06.01.10 20:45	10036	10036	10036
40	✓	38	N/U 13 5/8" riser and 18 3/4" BOP	32	100%	21,75 hrs	0,91	06.01.10 20:45	07.01.10 18:30	10036	10036	10036
54	✓	52	Pull Tubing	40	100%	35,25 hrs	1,47	07.01.10 18:30	09.01.10 05:45	10036	10036	10036
70		65	Install Reservoir Barrier (Section Mill, Underream and Balanced Cement Plug)	54	99%	255,75 hrs	10,66	09.01.10 05:45	19.01.10 21:30	10036	10036	10036
71		66	Set 9 7/8" EZSV above Tubing Cut		99%	62 hrs	2,58	09.01.10 05:45	11.01.10 19:45	10036	10036	10036
88	✓	76	Section Mill 165ft of 9 7/8" Casing	71	100%	128,5 hrs	5,35	11.01.10 19:45	17.01.10 04:15	9996	9996	9996
102	✓	86	Underream Open Hole	88	100%	28,25 hrs	1,18	17.01.10 04:15	18.01.10 08:30	9996	9996	9996
112	✓	95	Set Balanced Cement Plug	102	100%	37 hrs	1,54	18.01.10 08:30	19.01.10 21:30	9996	9996	9996
133		109	Install [redacted] Barriers (Section Mill, Underream and Balanced Cement Plug)	70	99%	365 hrs	15,21	19.01.10 21:30	04.02.10 02:30	9596	9596	9596
134	✓	110	Set 9 5/8" EZSV and cut 9 5/8" casing		100%	33,5 hrs	1,4	19.01.10 21:30	21.01.10 07:00	9596	9596	9596
149	✓	121	Section Mill 330ft of 9 5/8" Casing	134	100%	153,75 hrs	6,41	21.01.10 07:00	27.01.10 16:45	5960	5960	5960
186	✓	130	Underream Open Hole	149	100%	28,75 hrs	1,2	27.01.10 16:45	28.01.10 21:30	5960	5960	5960

Project: Plug & Abandonment-[redacted]
Date: Thu 23.04.15

Task	External Tasks	Manual Task	Finish-only
Split	External Milestone	Duration-only	Progress
Milestone	Inactive Task	Manual Summary Rollup	Deadline
Summary	Inactive Milestone	Manual Summary	
Project Summary	Inactive Summary	Start-only	

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ID		Orig ID	Task Name	Predecess	% Complet	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth	Orig Depth
197		139	Set Balanced Cement Plugs	186	99%	149 hrs	6,21	28.01.10 21:30	04.02.10 02:30	5960	5960	5960
225	✓	154	Install Surface Plug	133	100%	107,75 hrs	4,49	04.02.10 02:30	08.02.10 14:15	5410	5410	5410
226	✓	155	Remove Secondary Packoff		100%	9,75 hrs	0,41	04.02.10 02:30	04.02.10 12:15	5410	5410	5410
235	✓	164	Pull 9 5/8" Casing Tieback to surface	226	100%	85,25 hrs	3,55	04.02.10 12:15	08.02.10 01:30	5410	5410	5410
245	✓	172	Set Balanced Cement Plug	235	100%	12,75 hrs	0,53	08.02.10 01:30	08.02.10 14:15	5410	5410	5410
255		181	CONTINGENCY : Install [redacted]Barrier (Section Mill, Underream and Balanced Cement Plug)	225	0%	0 hrs	0	08.02.10 14:15	08.02.10 14:15	1240	1240	1240
320		246	CONTINGENCY : Install Surface Plug	255	0%	0 hrs	0	08.02.10 14:15	08.02.10 14:15	1240	1240	1240
329		255	N/D BOP / Riser	320	82%	57,75 hrs	2,41	08.02.10 14:15	11.02.10 00:00	400	400	400

Project: Plug & Abandonment-[redacted]
Date: Thu 23.04.15

Task	External Tasks	Manual Task	Finish-only
Split	External Milestone	Duration-only	Progress
Milestone	Inactive Task	Manual Summary Rollup	Deadline
Summary	Inactive Milestone	Manual Summary	
Project Summary	Inactive Summary	Start-only	

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Appendix B

ID		Orig ID	Task Name	Predecess	% Complet	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth
0	✓	0	**Plug & Abandonment-[redacted]**		100%	754,25 hrs	31,43	03.12.09 15:30	04.01.10 01:45	12580	12580
1	✓	1	**Skid rig from[redacted]to[redacted]**		100%	2,5 hrs	0,1	03.12.09 15:30	03.12.09 18:00	12580	12580
3	✓	3	**Rig Up on well [redacted]**	1	100%	11,75 hrs	0,49	03.12.09 18:00	04.12.09 05:45	12580	12580
9	✓	9	**Pull DHSV (Down Hole Safety valve)**	3	100%	1,75 hrs	0,07	04.12.09 05:45	04.12.09 07:30	12580	12580
12	✓	12	**Cut Tubing and Kill Well**	9	100%	30,25 hrs	1,26	04.12.09 07:30	05.12.09 13:45	12580	12580
23	✓	21	**Contingency: Tubing punch and cut with Radial Cutting Tool (RCT)**	12	100%	0 hrs	0	05.12.09 13:45	05.12.09 13:45	12555	12555
32	✓	30	**Nipple Down X-mas Tree**	23	100%	8 hrs	0,33	05.12.09 13:45	05.12.09 21:45	12555	12555
40	✓	38	**N/U 13 5/8" riser and 18 3/4" BOP**	32	100%	20,5 hrs	0,85	05.12.09 21:45	06.12.09 18:15	12555	12555
55	✓	51	**Pull Tubing**	40	100%	42,5 hrs	1,77	06.12.09 18:15	08.12.09 12:45	12555	12555
68	✓	64	**Install Reservoir Barrier (Section Mill, Underream and Balanced Cement Plug)**	55	100%	253,75 hrs	10,57	08.12.09 12:45	19.12.09 02:30	12555	12555
69	✓	65	**Set 9 7/8" EZSV above Tubing Cut**		100%	34,25 hrs	1,43	08.12.09 12:45	09.12.09 23:00	12555	12555
70	✓	66	Hold SJA mtg		100%	0 hrs	0	08.12.09 12:45	08.12.09 12:45	12555	12555
71	✓	67	M/U clean out trip assembly	70	100%	1,5 hrs	0.06	08.12.09 12:45	08.12.09 14:15	12555	12555
72	✓	68	RIH on 5" drill pipe to 11 081ft, tagged obstruction.	71	100%	8 hrs	0.33	08.12.09 14:15	08.12.09 22:15	12555	12555
73	✓	69	Polish EZSV setting area and circulate well clean with 14.3 ppg mud.	72	100%	2,5 hrs	0,1	08.12.09 22:15	09.12.09 00:45	12555	12555
74	✓	70	Flow check well. POOH and rack back Clean out BHA	73	100%	8,25 hrs	0,34	09.12.09 00:45	09.12.09 09:00	12555	12555
75	✓	71	M/U 9 7/8" EZSV and RIH to 11 030 ft	74	100%	7,25 hrs	0,3	09.12.09 09.00	09.12.09 16.15	12555	12555
76	✓	72	Set 9 7/8" EZSV at ±11 030 ft, load test to 22 klbs	75	100%	0,5 hrs	0.02	09.12.09 16.15	09.12.09 16:45	12555	12555
77	✓		Displace well to milling fluid	76	100%	1,5 hrs	0.06	09.12.09 16:45	09.12.09 18:15	12555	12555
78	✓	73	Pull out of hole and lay down running tool.	77	100%	4,75 hrs	0,2	09.12.09 18:15	09.12.09 23:00	12540	12540
79	✓	74	POOH to cutter depth of ±11577 ft (+/-273 ft above EZSV)	78	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
80	✓	75	Cut 6" window in 9-7/8 casing (5-10 ft above collar)	79	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
81	✓	76	Drop ball and open circ sub. Circ and condition mud	80	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
82	✓	77	Pump OOH 3-5 stands. Flow check well.	81	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
83	✓	78	Slug pipe and POOH with Casing cutter / EZSV assembly	82	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
84	✓	79	Lay down Casing Cutter / EZSV assembly.	83	100%	0 hrs	0	09.12.09 23:00	09.12.09 23:00	12540	12540
85	✓	80	**Section Mill 165ft of 9 7/8" Casing**	69	100%	155,75 hrs	6,49	09.12.09 23:00	16.12.09 10:45	12540	12540
86	✓	81	Hold SJA mtg		100%	0,25 hrs	0.01	09.12.09 23:00	09.12.09 23:15	12540	12540
87	✓	82	MU 9 7/8" casing section mill BHA and test knives	86	100%	3 hrs	0.13	09.12.09 23:15	10.12.09 02:15	12540	12540
88	✓	83	Function test BOP	87	100%	0 hrs	0	10.12.09 02:15	10.12.09 02:15	12540	12540
89	✓	84	RIH with 9 7/8" section assembly to 10 755 ft	88	100%	6 hrs	0,25	10.12.09 02:15	10.12.09 08:15	12540	12540
90	✓	85	Fill pipe and prepare to cut/mill casing	89	100%	0,5 hrs	0,02	10.12.09 08:15	10.12.09 08:45	12540	12540
91	✓	86	Section Mill from 10 755 ft - 10 809 ft	90	100%	23,75 hrs	0,99	10.12.09 08:45	11.12.09 08:30	12540	12540
92	✓		Work stuck string	91	100%	34,75 hrs	1.45	11.12.09 08:30	12.12.09 19:15	12540	12540
93	✓		Continue milling from 10 809 ft - 10 856 ft.	92	100%	22,5 hrs	0,94	12.12.09 19:15	13.12.09 17:45	12540	12540
94	✓		Circulate hole and displace to kill fluid. Flow check and pump slug	93	100%	6,25 hrs	0,26	13.12.09 17:45	14.12.09 00:00	12540	12540
95	✓		Pull out of hole	94	100%	7,75 hrs	0,32	14.12.09 00:00	14.12.09 07:45	12540	12540
96	✓		Replace failed section mill and Sentio tool.	95	100%	2 hrs	0,08	14.12.09 07:45	14.12.09 09:45	12540	12540
97	✓		Run back in hole	96	100%	10,5 hrs	0.44	14.12.09 09:45	14.12.09 20:15	12540	12540
98	✓		Displace well back to milling fluid	97	100%	3,25 hrs	0,14	14.12.09 20:15	14.12.09 23:30	12540	12540
99	✓		Continue section milling from 10 856 ft - 10 896 ft.	98	100%	13.5 hrs	0,56	14.12.09 23:30	15.12.09 13:00	12540	12540
100	✓	87	Circulate hole clean and displace to kill fluid for tripping	99	100%	9,25 hrs	0,39	15.12.09 13:00	15.12.09 22:15	12540	12540
101	✓		Flow check and let well flow back.	100	100%	3,5 hrs	0,15	15.12.09 22:15	16.12.09 01:45	12540	12540
102	✓	88	POOH with 9 7/8" section mill to surface	101	100%	7,75 hrs	0.32	16.12.09 01:45	16.12.09 09:30	12540	12540
103	✓	89	Jetwash well head / BOP	102	100%	1.25 hrs	0,05	16.12.09 09:30	16.12.09 10:45	12540	12540
104	✓	90	Test BOP, incl annular TDS and standpipe manifold.	103	100%	0 hrs	0	16.12.09 10:45	16.12.09 10:45	12540	12540
105	✓	91	Clean and clear rig floor	104	100%	0 hrs	0	16.12.09 10:45	16.12.09 10:45	12540	12540
106	✓	92	**Underream Open Hole**	85	100%	31,5 hrs	1,31	16.12.09 10:45	17.12.09 18:15	12540	12540
107	✓	93	Hold SJA mtg		100%	0 hrs	0	16.12.09 10:45	16.12.09 10:45	12540	12540
108	✓	94	MU 8 1/2" UR800 underreamer BHA. Function Test	107	100%	2,5 hrs	0,1	16.12.09 10:45	16.12.09 13:15	12540	12540
109	✓		Slip and cut drill line.	108	100%	2 hrs	0.08	16.12.09 13:15	16.12.09 15:15	12540	12540
110	✓	95	RIH to 10.755 ft	109	100%	6.25 hrs	0,26	16.12.09 15:15	16.12.09 21:30	12540	12540
111	✓	96	Underream f/10,755 ft to 10,896 ft	110	100%	8,5 hrs	0,35	16.12.09 21:30	17.12.09 06:00	12540	12540
112	✓	97	Circulate hole clean.	111	100%	1 hr	0,04	17.12.09 06:00	17.12.09 07:00	12540	12540

25 Oct '09
S S M T W T F

Project: Plug & Abandonment- [redacted]
Date: Thu 23.04.15

Task | Split | Milestone | Summary | Project Summary | External Tasks | External Milestone | Inactive Task | Inactive Milestone | Inactive Summary | Manual Task | Duration-only | Manual Summary Rollup | Manual Summary | Start-only | Finish-only | Progress | Deadline

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ID		Orig ID	Task Name	Predecess	% Complete	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth
113	✓	98	Flow check well.	112	100%	2,5 hrs	0,1	17.12.09 07:00	17.12.09 09:30	12540	12540
114	✓	99	Pump Slug. POOH and L/D BHA	113	100%	8,5 hrs	0,35	17.12.09 09:30	17.12.09 18:00	12540	12540
115	✓	100	Clean and clear rig floor, drift 3 1/2" dp in derrick	114	100%	0,25 hrs	0,01	17.12.09 18:00	17.12.09 18:15	12540	12540
116	✓	**101**	**Set Balanced Cement Plug**	**106**	**100%**	**32,25 hrs**	**1,34**	**17.12.09 18:15**	**18.12.09 02:30**	**12540**	**12540**
117	✓	102	Hold SJA mtg		100%	0,5 hrs	0,02	17.12.09 18:15	17.12.09 18:45	12540	12540
118	✓	103	RIH cement diverter/centraliser + 18 jts 3 1/2" DP on 5" DP ± 11 000 ft	117	100%	8 hrs	0,33	17.12.09 18:45	18.12.09 02:45	12540	12540
119	✓	104	Wash down to EZSV at 11 030 ft	118	100%	1,5 hrs	0,06	18.12.09 02:45	18.12.09 04:15	12540	12540
120	✓	105	Circ and condition mud	119	100%	2 hrs	0,08	18.12.09 04:15	18.12.09 06:15	12540	12540
121	✓		Problems to operate drilling handling equipment due to low temp and ice.	120	100%	2 hrs	0,13	18.12.09 06:15	18.12.09 08:15	12540	12540
122	✓		Rig repair. Drillers chair. Loose el. Connection	121	100%	0,5 hrs	0,02	18.12.09 08:15	18.12.09 08:45	12540	12540
123	✓		TBT to rig up cmt head.	122	100%	0,25 hrs	0,01	18.12.09 09:45	18.12.09 10:00	12540	12540
124	✓	106	Rig up cement line and test to 5,000 psi	123	100%	1 hr	0,04	18.12.09 10:00	18.12.09 11:00	12540	12540
125	✓	107	Spot a 400 ft balanced cement plug from ±11 030 ft to ± 10 630 ft	124	100%	1,75 hrs	0,07	18.12.09 11:00	18.12.09 12:45	12140	12140
126	✓	108	Pull above plug. Drop 2 sponge balls and circulate DP clean	125	100%	4,25 hrs	0,18	18.12.09 12:45	18.12.09 17:00	12140	12140
127	✓		Flow check	126	100%	0,75 hrs	0,03	18.12.09 17:00	18.12.09 17:45	12140	12140
128	✓	109	Pump Slug and POOH to surface racking back 3 1/2" cement stinger	127	100%	7,25 hrs	0,3	18.12.09 17:45	19.12.09 01:00	12140	12140
129	✓		Wash/Jet W.H and BOP	128	100%	1,5 hrs	0,06	19.12.09 01:00	19.12.09 02:30	12140	12140
130	✓	110	WOC until 1000 psi UCA compressive strength.	129	100%	0 hrs	0	19.12.09 02:30	19.12.09 02:30	12140	12140
131	✓	111	Pressure test cement plug to 1800 psi with 14.3 ppg mud	130	100%	0 hrs	0	19.12.09 02:30	19.12.09 02:30	12140	12140
132	✓	**112**	**Install [redacted] Barriers (Section Mill, Underream and Balanced Cement Plug)**	**88**	**100%**	**310,25 hrs**	**12,93**	**19.12.09 02:30**	**01.01.10 00:45**	**12140**	**12140**
133	✓	**113**	**Set 9 5/8" EZSV**		**100%**	**48,5 hrs**	**2,02**	**19.12.09 02:30**	**21.12.09 03:00**	**12140**	**12140**
134	✓	114	Hold SJA mtg (clear/clean rig floor and TBT)		100%	0,5 hrs	0,02	19.12.09 02:30	19.12.09 03:00	12140	12140
135	✓	115	M/U 9 5/8" casing cutter BHA and function test	134	100%	1 hr	0,04	19.12.09 03:00	19.12.09 04:00	12140	12140
136	✓	116	M/U 9 5/8" EZSV with 9 5/8" pipe cutter BHA and RIH to 6250 ft	135	100%	6,25 hrs	0,26	19.12.09 04:00	19.12.09 10:15	12140	12140
137	✓		WOC until 1000 psi UCA compressive strength.??	136	100%	0 hrs	0	19.12.09 10:15	19.12.09 10:15	12140	12140
138	✓		Pressure test cement plug to 1800 psi with 14.3 ppg mud	137	100%	1,5 hrs	0,06	19.12.09 10:15	19.12.09 11:45	12140	12140
139	✓	117	Set 9 7/8" EZSV at ± 6250 ft. load test to 22 klbs	138	100%	0,75 hrs	0,03	19.12.09 11:45	19.12.09 12:30	6250	6250
140	✓	118	POOH to cutter depth of ±5830 ft Perform TBT	139	100%	0,75 hrs	0,03	19.12.09 12:30	19.12.09 13:15	6250	6250
141	✓		M/u BOP test plug. RIH and hang off string in well head (on top of wear bushing)	140	100%	1 hr	0,04	19.12.09 13:15	19.12.09 14:15	6250	6250
142	✓	119	Open annular and clean out. Test BOP and refill annular with grease.	141	100%	28,5 hrs	1,19	19.12.09 14:15	20.12.09 18:45	6250	6250
143	✓	120	Pull and lay down test plug.	142	100%	1,25 hrs	0,05	20.12.09 18:45	20.12.09 20:00	6250	6250
144	✓	121	Cut 6" window in 9 5/8" casing (5-10 ft above collar)	143	100%	1,25 hrs	0,05	20.12.09 20:00	20.12.09 21:15	6250	6250
145	✓	122	Drop ball and open circ sub. Circ and condition mud.	144	100%	1,5 hrs	0,06	20.12.09 21:15	20.12.09 22:45	6250	6250
146	✓		Pump OOH 3-5 stands. Flow check well	145	100%	0 hrs	0	20.12.09 22:45	20.12.09 22:45	6250	6250
147	✓	123	Slug pipe and POOH with Casing cutter / EZSV assembly	146	100%	4,25 hrs	0,18	20.12.09 22:45	21.12.09 03:00	6250	6250
148	✓	**124**	**Section Mill 330ft of 9 5/8" Casing**	**133**	**100%**	**148 hrs**	**6,17**	**21.12.09 03:00**	**27.12.09 07:00**	**6250**	**6250**
149	✓	125	Hold SJA mtg		100%	0 hrs	0	21.12.09 03:00	21.12.09 03:00	6250	6250
150	✓	126	M/U 9 5/8" casing section mill BHA and test knives	149	100%	2 hrs	0,08	21.12.09 03:00	21.12.09 05:00	6250	6250
151	✓	127	RIH with 9 5/8" section assembly to 6" cut depth at ±5830 ft	150	100%	4,5 hrs	0,19	21.12.09 05:00	21.12.09 09:30	6250	6250
152	✓	128	Displace Mud system to Milling Fluid	151	100%	5,75 hrs	0,24	21.12.09 09:30	21.12.09 15:15	6250	6250
153	✓	129	Section Mill from 5825 ft - 5962 ft	152	100%	53,5 hrs	2,23	21.12.09 15:15	23.12.09 20:45	6250	6250
154	✓		Circulate hole clean and displace to tripping mud.	153	100%	5,25 hrs	0,22	23.12.09 20:45	24.12.09 02:00	6250	6250
155	✓		POOH. Change to new knives and RIH. Displace to milling fluid	154	100%	14,25 hrs	0,59	24.12.09 02:00	24.12.09 16:15	6250	6250
156	✓		Section mill from 5962 ft to 6074 ft	155	100%	20,25 hrs	0,84	24.12.09 16:15	25.12.09 12:30	6250	6250
157	✓		Work stuck pipe free and circulate hole clean.	156	100%	7,5 hrs	0,31	25.12.09 12:30	25.12.09 20:00	6250	6250
158	✓		Section mill from 6074 ft to 6155 ft	157	100%	15,75 hrs	0,66	25.12.09 20:00	26.12.09 11:45	6250	6250
159	✓		Circulate hole clean and POOH/ work pipe out to 5734 ft	158	100%	8,25 hrs	0,34	26.12.09 11:45	26.12.09 20:00	6250	6250
160	✓	130	Circulate hole clean and displace to kill fluid for tripping	159	100%	2,25 hrs	0,09	26.12.09 20:00	26.12.09 22:15	6250	6250
161	✓	131	POOH with 9 5/8" section mill to surface	160	100%	8,75 hrs	0,36	26.12.09 22:15	27.12.09 07:00	6250	6250
162	✓	132	Clean and clear rig floor	161	100%	0 hrs	0	27.12.09 07:00	27.12.09 07:00	6250	6250
163	✓	**133**	**Underream Open Hole**	**148**	**100%**	**70,75 hrs**	**2,95**	**27.12.09 07:00**	**30.12.09 05:45**	**6250**	**6250**
164	✓	134	Hold TBT mtg		100%	0,25 hrs	0,01	27.12.09 07:00	27.12.09 07:15	6250	6250
165	✓	135	M/U 8 1/2" UR800 underreamer BHA. Function Test	164	100%	2,25 hrs	0,09	27.12.09 07:15	27.12.09 09:30	6250	6250
166	✓	136	RIH to 5833 ft	165	100%	4,25 hrs	0,18	27.12.09 09:30	27.12.09 13:45	6250	6250
167	✓		Attempt to under ream. Hole packed off. Work pipe back to 5825'. Circulate	166	100%	5,5 hrs	0,23	27.12.09 13:45	27.12.09 19:15	6250	6250

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Project: Plug & Abandonment- [redacted]
Date: Thu 23.04.15

Task · Split · Milestone · Summary · Project Summary · External Tasks · External Milestone · Inactive Task · Inactive Milestone · Inactive Summary · Manual Task · Duration-only · Manual Summary Rollup · Manual Summary · Start-only · Finish-only · Progress · Deadline

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ID	Indicators	Orig ID	Task Name	Predecess	% Complet	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth
168	✓		Flow check. POOH	167	100%	4,75 hrs	0,2	27.12.09 19:15	28.12.09 00:00	6250	6250
169	✓		Clean & clear rig floor	168	100%	0,25 hrs	0,01	28.12.09 00:00	28.12.09 00:15	6250	6250
170	✓		M/U and RIH w/ clean up assembly	169	100%	5,5 hrs	0,23	28.12.09 00:15	28.12.09 05:45	6250	6250
171	✓		Clean up from 5825 ft to 6204 ft	170	100%	12 hrs	0,5	28.12.09 05:45	28.12.09 17:45	6250	6250
172	✓		Pump out of window up to 5825 ft. Circulate bottoms up	171	100%	6,5 hrs	0,27	28.12.09 17:45	29.12.09 00:15	6250	6250
173	✓		POOH	172	100%	5,25 hrs	0,22	29.12.09 00:15	29.12.09 05:30	6250	6250
174	✓		Change saver sub	173	100%	0,75 hrs	0,03	29.12.09 05:30	29.12.09 06:15	6250	6250
175	✓		M/U Under reamer BHA. Function test.	174	100%	1 hr	0,04	29.12.09 06:15	29.12.09 07:15	6250	6250
176	✓		RIH to 400 ft	175	100%	0,75 hrs	0,03	29.12.09 07:15	29.12.09 08:00	6250	6250
177	✓		Repair PHM	176	100%	1,5 hrs	0,06	29.12.09 08:00	29.12.09 09:30	6250	6250
178	✓		Rih to 2250 ft	177	100%	1,5 hrs	0,06	29.12.09 09:30	29.12.09 11:00	6250	6250
179	✓		Repair Fingerboard	178	100%	0,25 hrs	0,01	29.12.09 11:00	29.12.09 11:15	6250	6250
180	✓		Rih to 5883 ft	179	100%	2,5 hrs	0,1	29.12.09 11:15	29.12.09 13:45	6250	6250
181	✓		Circ and condition mud	180	100%	1,75 hrs	0,07	29.12.09 13:45	29.12.09 15:30	6250	6250
182	✓	137	Underream open hole to 16" from 5877 ft to 6155 ft (278 ft)	181	100%	4 hrs	0,17	29.12.09 15:30	29.12.09 19:30	6250	6250
183	✓	138	Circulate hole clean.	182	100%	1,25 hrs	0,05	29.12.09 19:30	29.12.09 20:45	6250	6250
184	✓	139	Pump out of open hole and flow check well.	183	100%	1,25 hrs	0,05	29.12.09 20:45	29.12.09 22:00	6250	6250
185	✓		Circ hole clean	184	100%	1,25 hrs	0,05	29.12.09 22:00	29.12.09 23:15	6250	6250
186	✓		Flow check	185	100%	0,25 hrs	0,01	29.12.09 23:15	29.12.09 23:30	6250	6250
187	✓	140	Pump Slug. POOH and L/D BHA	186	100%	6 hrs	0,25	29.12.09 23:30	30.12.09 05:30	6250	6250
188	✓	141	Clean and clear rig floor, drift 3 1/2" dp in derrick	187	100%	0,25 hrs	0,01	30.12.09 05:30	30.12.09 05:45	6250	6250
189	✓	**142**	**Set Balanced Cement Plugs**	**163**	**100%**	**43 hrs**	**1,79**	**30.12.09 05:45**	**01.01.10 00:45**	**6250**	**6250**
190	✓	143	Hold SJA mtg		100%	0,25 hrs	0,01	30.12.09 05:45	30.12.09 06:00	6250	6250
191	✓	144	RIH cement diverter/centraliser + 18 jts 3 1/2" DP on 5" DP ± 5830 ft	190	100%	4,75 hrs	0,2	30.12.09 06:00	30.12.09 10:45	6250	6250
192	✓	145	Wash down to EZSV at 6286 ft	191	100%	2,75 hrs	0,11	30.12.09 10:45	30.12.09 13:30	6250	6250
193	✓	146	Circ and condition mud	192	100%	1,25 hrs	0,05	30.12.09 13:30	30.12.09 14:45	6250	6250
194	✓	147	Rig up cement line and test to 5,000 psi	193	100%	1 hr	0,04	30.12.09 14:45	30.12.09 15:45	6250	6250
195	✓	148	Spot a 336 ft balanced cement plug from ±6286 ft to ±5950 ft	194	100%	1,5 hrs	0,06	30.12.09 15:45	30.12.09 17:15	5700	5950
196	✓	149	Pull above plug (+- 5650 ft). Drop 2 sponge balls and circulate DP clean	195	100%	2,25 hrs	0,09	30.12.09 17:15	30.12.09 19:30	5700	5950
197	✓	150	WOC. Perform misc rig repair and rig service	196	100%	11 hrs	0,46	30.12.09 19:30	31.12.09 06:30	5700	5950
198	✓		Wash down to 5967 ft, circ and condition mud	197	100%	5,75 hrs	0,24	31.12.09 06:30	31.12.09 12:15	5700	5950
199	✓	151	Weight test cement plug to 22 klbs	198	100%	0,25 hrs	0,01	31.12.09 12:15	31.12.09 12:30	5700	5950
200	✓	152	Spot a 250 ft balanced cement plug from ±5950 ft to ±5700 ft	199	100%	2,5 hrs	0,1	31.12.09 12:30	31.12.09 15:00	5700	5650
201	✓	153	Pull above plug. Drop 2 sponge balls and circulate DP clean	200	100%	3,25 hrs	0,14	31.12.09 15:00	31.12.09 18:15	5700	5650
202	✓	154	Pump Slug and POOH to surface racking back 3 1/2" cement stinger	201	100%	3,75 hrs	0,16	31.12.09 18:15	31.12.09 22:00	5700	5650
203	✓		Jet wash Bop and well head	202	100%	1 hr	0,04	31.12.09 22:00	31.12.09 23:00	5700	5650
204	✓		Cut and slip drill line	203	100%	1,75 hrs	0,07	31.12.09 23:00	01.01.10 00:45	5700	5650
205	✓	155	WOC until 1000 psi UCA compressive strength: Canceled - do later	204	100%	0 hrs	0	01.01.10 00:45	01.01.10 00:45	5700	5650
206	✓	156	Pressure test cement plug to 1450 psi with 14.3 ppg mud: Canceled - do later	205	100%	0 hrs	0	01.01.10 00:45	01.01.10 00:45	5700	5650
207	✓	**157**	**Install Surface Plug**	**132**	**100%**	**39,75 hrs**	**1,66**	**01.01.10 00:45**	**02.01.10 16:30**	**5700**	**5650**
208	✓		**Cut 9 5/8" casing at 2000 ft**		**100%**	**11 hrs**	**0,46**	**01.01.10 00:45**	**01.01.10 11:45**	**5700**	**5650**
209	✓	169	M/U 9 5/8" casing cutter BHA and function test		100%	0,75 hrs	0,03	01.01.10 00:45	01.01.10 01:30	5700	5650
210	✓	170	RIH with 9 5/8" cutter to ±2000 ft	209	100%	1,5 hrs	0,06	01.01.10 01:30	01.01.10 03:00	5700	5650
211	✓		WOC to reach 1000 psi strength in UCA-cell (if necessary)	210	100%	0 hrs	0	01.01.10 03:00	01.01.10 03:00	5700	5650
212	✓		Pressure test cement plug to 1450 psi with 14.3 ppg mud in hole	211	100%	1 hr	0,04	01.01.10 03:00	01.01.10 04:00	5700	5650
213	✓	171	Cut 9 5/8 casing at +- 2000 ft (5-10 ft above coupling)	212	100%	0,5 hrs	0,02	01.01.10 04:00	01.01.10 04:30	2000	2000
214	✓		Displace B annulus to 14,3 ppg mud	213	100%	2 hrs	0,08	01.01.10 04:30	01.01.10 06:30	2000	2000
215	✓		Trouble shoot unstabile flow check	214	100%	3,5 hrs	0,15	01.01.10 06:30	01.01.10 10:00	2000	2000
216	✓	172	POOH with 9 5/8" cutter	215	100%	1,75 hrs	0,07	01.01.10 10:00	01.01.10 11:45	2000	2000
217	✓	**158**	**Remove Secondary Packoff**	**209**	**100%**	**8 hrs**	**0,33**	**01.01.10 11:45**	**01.01.10 19:45**	**2000**	**2000**
218	✓	159	Back out 9 5/8" csg hgr hold down bolts		100%	0 hrs	0	01.01.10 11:45	01.01.10 11:45	2000	2000
219	✓	160	Retrieve WB. Pressure test hold down bolts to 2500 psi against well.	218	100%	3,75 hrs	0,16	01.01.10 11:45	01.01.10 15:30	2000	2000
220	✓	161	Hold SJA mtg	219	100%	0 hrs	0	01.01.10 15:30	01.01.10 15:30	2000	2000
221	✓	162	M/U 246 mm OD bladed casing mill assembly	220	100%	0,75 hrs	0,03	01.01.10 15:30	01.01.10 16:15	2000	2000
222	✓	163	RIH to 3 ft above upper 2 1/16" 5M outlet	221	100%	0,75 hrs	0,03	01.01.10 16:15	01.01.10 17:00	2000	2000

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Task	Project Summary	Inactive Milestone	Manual Summary Rollup	Progress	
Split	External Tasks	Inactive Summary	Manual Summary	Deadline	
Milestone	External Milestone	Manual Task	Start-only		
Summary	Inactive Task	Duration-only	Finish-only		

ID	Orig ID	Task Name	Predecessors	% Complete	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth
223	164	Mill away shoulder (approx 210 mm) to release secondary pack off	222	100%	1,5 hrs	0,06	01.01.10 17:00	01.01.10 18:30	2000	2000
224	165	Inspect TDS. Circulate swarf OOH. Flow check.	223	100%	0,75 hrs	0,03	01.01.10 18:30	01.01.10 19:15	2000	2000
225	166	POOH and LD milling BHA	224	100%	0,5 hrs	0,02	01.01.10 19:15	01.01.10 19:45	2000	2000
226	**167**	**Pull 9 5/8" Casing to 2000 ft**	**217**	**100%**	**11,5 hrs**	**0,48**	**01.01.10 19:45**	**02.01.10 07:15**	**2000**	**2000**
227	168	Hold SJA mtg		100%	0,25 hrs	0,01	01.01.10 19:45	01.01.10 20:00	2000	2000
228	169	M/U 9 5/8" casing cutter BHA and function test	227	100%	0 hrs	0	01.01.10 20:00	01.01.10 20:00	2000	2000
229	170	RIH with 9 5/8" cutter to ±2000 ft	228	100%	0 hrs	0	01.01.10 20:00	01.01.10 20:00	2000	2000
230	171	Cut 9 5/8 casing (10 ft above coupling)	229	100%	0 hrs	0	01.01.10 20:00	01.01.10 20:00	2000	2000
231	172	POOH with 9 5/8" cutter	230	100%	0 hrs	0	01.01.10 20:00	01.01.10 20:00	2000	2000
232	173	M/U & RIH with 9 5/8" Spear w/ pack-off and engage casing	231	100%	1 hr	0,04	01.01.10 20:00	01.01.10 21:00	2000	2000
233		Pull casing free and circ behind casing	232	100%	0,75 hrs	0,03	01.01.10 21:00	01.01.10 21:45	2000	2000
234	174	Pull 9 5/8" casing hanger to surface	233	100%	0,25 hrs	0,01	01.01.10 21:45	01.01.10 22:00	2000	2000
235	176	Continue R/U Franks casing eqt	234	100%	2 hrs	0,08	01.01.10 22:00	02.01.10 00:00	2000	2000
236	177	Pull and L/D Casing from 2000 ft. mark joints for inspection per COPNo guidelines	235	100%	5,5 hrs	0,23	02.01.10 00:00	02.01.10 05:30	2000	2000
237	178	R/D Franks casing eqt	236	100%	1,75 hrs	0,07	02.01.10 05:30	02.01.10 07:15	2000	2000
238	**179**	**Set Balanced Cement Plug**	**226**	**100%**	**9,25 hrs**	**0,39**	**02.01.10 07:15**	**02.01.10 16:30**	**2000**	**2000**
239	180	Hold SJA mtg		100%	0 hrs	0	02.01.10 07:15	02.01.10 07:15	2000	2000
240	181	M/U 13 3/8" EZSV with brush	239	100%	0,25 hrs	0,01	02.01.10 07:15	02.01.10 07:30	2000	2000
241	182	RIH & set EZSV @ 1925 ft md, weight test to 22 klbs.	240	100%	3,25 hrs	0,14	02.01.10 07:30	02.01.10 10:45	1925	1925
242	183	Displace well to seawater	241	100%	0,5 hrs	0,02	02.01.10 10:45	02.01.10 11:15	1925	1925
243	184	R/u cmt swivel + surface lines & test same	242	100%	1,5 hrs	0,06	02.01.10 11:15	02.01.10 12:45	1925	1925
244	185	Set ±660 ft (200m) balanced cement plug	243	100%	1 hr	0,04	02.01.10 12:45	02.01.10 13:45	1265	1265
245	186	Pull above cement plug, drop 2 sponge balls and circ DP clean	244	100%	1,75 hrs	0,07	02.01.10 13:45	02.01.10 15:30	1265	1265
246	187	POOH with EZSV running tool and L/D	245	100%	1 hr	0,04	02.01.10 15:30	02.01.10 16:30	1265	1265
247	**188**	**CONTINGENCY : Install [redacted] Barrier (Section Mill, Underream and Balanced Cement Plug)**	**207**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
248	**189**	**Remove Secondary Packoff**		**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
249	190	Back out 9 5/8" csg hgr hold down bolts		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
250	191	Retrieve WB. Pressure test hold down bolts to 2500 psi against well.	249	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
251	192	Hold SJA mtg	250	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
252	193	M/U 346 mm OD bladed casing mill assembly	251	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
253	194	RIH to 3 ft above upper 2 1/16" 5M outlet	252	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
254	195	Mill away shoulder (approx 210 mm) to release secondary pack off	253	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
255	196	Inspect TDS. Circulate swarf OOH. Flow check.	254	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
256	197	POOH and LD milling BHA	255	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
257	**198**	**Pull 9 5/8" Casing from PBR above 9 5/8" Hanger**	**248**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
258	199	Hold SJA mtg		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
259	200	M/U & RIH with 9 5/8" Spear w/ pack-off and engage casing	258	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
260	201	Pull 9 5/8" casing free (surface to +/- 3000 ft)	259	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
261	202	Displace B annulus to 14.3 WBM	260	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
262	203	Pull casing to surface and release spear.Pre-job meeting, R/U Casing handling equipment. Flow	261	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
263	204	Pull and L/D Casing, mark joints for inspection per COPNo guidelines	262	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
264	205	R/D Franks casing handling equipment. Store on R.F.	263	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
265	**206**	**Recover PBR and mill 9 5/8" Liner top packer**	**257**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
266	207	Hold SJA mtg		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
267	208	RIH with B spear to PBR at 3015 ft	266	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
268	209	Engage spear (to the left). Perform stretch tests	267	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
269	210	Back out upper PBR (20 turns left)	268	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
270	211	Perform flow check	269	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
271	212	POOH & lay down PBR	270	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
272	213	M/U Junk mill BHA and RIH	271	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
273	214	Mill TSP slips and packer element.	272	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
274	215	Perform flow check	273	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
275	216	POOH Junk mill assy.	274	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
276	**217**	**Recover 9 5/8" Casing**	**265**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
277	218	Hold SJA mtg		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265

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S S M T W T F

Project: Plug & Abandonment-[redacted]
Date: Thu 23.04.15

Task, Split, Milestone, Summary, Project Summary, External Tasks, External Milestone, Inactive Task, Inactive Milestone, Inactive Summary, Manual Task, Duration-only, Manual Summary Rollup, Manual Summary, Start-only, Finish-only, Progress, Deadline

ID		Orig ID	Task Name	Predecess	% Complet	Duration (hrs)	Duration (days)	Start	Finish	Trgt Depth	Act Depth
278	✓	219	M/U cut/pull assy (cutter+motor+B spear) and RIH.	277	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
279	✓	220	RIH and engage B spear at top of liner	278	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
280	✓	221	Cut casing below liner hanger with motor	279	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
281	✓	222	Drop ball to open circ sub	280	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
282	✓	223	Pooh and L/D liner hanger	281	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
283	✓	224	RIH cut and pull BHA (±5850 ft cutter depth, ±3050 ft B spear depth)	282	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
284	✓	225	Engage 9 5/8" spear, perform stretch test	283	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
285	✓	226	Cut Casing at ±5850 ft	284	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
286	✓	227	Check fish is free, drop ball to open circ sub above B spear	285	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
287	✓	228	Flow check. Disengage spear and POOH	286	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
288	✓	229	RIH too spear and engage casing at ±3050 ft	287	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
289	✓	230	Circulate behind casing fish, flow check and POOH	288	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
290	✓	231	Rig up Franks casing gear	289	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
291	✓	232	POOH and L/D 9 5/8" casing	290	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
292	✓	233	R/D Casing handling equipment, Clean and tidy rig floor	291	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
293	✓	234	M/U and RIH w/ Casing Mill to 9 5/8" csg stub at ± 5850ft	292	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
294	✓	235	Mill 9 5/8" Casing down to 6042ft. (166ft of open hole)	293	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
295	✓	236	Circ Hole clean. POOH with casing mill.	294	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
296	✓	**237**	**Install [redacted] Barriers**	**276**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
297	✓	238	Hold SJA mtg		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
298	✓	239	M/U and RIH UR1200 Underreamer to 13 3/8" shoe	297	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
299	✓	240	Underream from 13 3/8" shoe to casing stump at ± 6042 ft	298	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
300	✓	241	Circ & condition mud for cementing. Reduce mud viscosity for cementing	299	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
301	✓	242	POOH and L/D UR1200 Underreamer	300	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
302	✓	243	Jet wash well head and bop cavity	301	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
303	✓	244	RIH with 3 1/2" cement stinger to 9 5/8" EZSV at 6200 ft	302	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
304	✓	245	Circulate one DP volume	303	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
305	✓	246	Set 500 ft balanced cement plug 3 [redacted] Barrier #1)	304	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
306	✓	247	Pull above cement, drop 2 sponge balls and circulate clean	305	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
307	✓	248	WOC UCA > 1000 psi	306	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
308	✓	249	Wash down and tag with 22 klbs. Pressure test to 1450 psi	307	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
309	✓	250	Set 400 ft balanced cement plug ([redacted] Barrier #2)	308	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
310	✓	251	Pull above cement, drop 2 sponge balls and circulate clean	309	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
311	✓	252	POOH	310	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
312	✓	**253**	**CONTINGENCY : Install Surface Plug**	**247**	**100%**	**0 hrs**	**0**	**02.01.10 16:30**	**02.01.10 16:30**	**1265**	**1265**
313	✓	254	Pre job meeting		100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
314	✓	255	M/U 13 3/8" EZSV with brush	313	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
315	✓	256	RIH & set EZSV @ 1925 ft mD, weight test to 22 klbs.	314	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
316	✓	257	Displace well to seawater	315	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
317	✓	258	R/u cmt swivel + surface lines & test same	316	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
318	✓	259	Set ±660 ft (200m) balanced cement plug (NOTE: absolute minimum is 100m/330 ft)	317	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
319	✓	260	Pull above cement plug, drop 2 sponge balls and circ DP clean	318	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
320	✓	261	POOH with EZSV running tool and L/D	319	100%	0 hrs	0	02.01.10 16:30	02.01.10 16:30	1265	1265
321	✓	**262**	**N/D BOP / Riser**	**312**	**100%**	**33,25 hrs**	**1,39**	**02.01.10 16:30**	**04.01.10 01:45**	**400**	**400**
322	✓	263	Jet was Bop, Test 13 3/8 casing and N/D Diverter		100%	7,5 hrs	0,31	02.01.10 16:30	03.01.10 00:00	400	400
323	✓		Inspect and clean annular	322	100%	4 hrs	0,17	03.01.10 00:00	03.01.10 04:00	400	400
324	✓		Nipple down riser and Bop	323	100%	15 hrs	0,63	03.01.10 04:00	03.01.10 19:00	400	400
325	✓	264	Install Pressure Cap on Wellhead	324	100%	1 hr	0,04	03.01.10 19:00	03.01.10 20:00	400	400
326	✓		Skid in cantilever to get access to [redacted] platform with [redacted]	325	100%	1,75 hrs	0,07	03.01.10 20:00	03.01.10 21:45	400	400
327	✓		Remove excess equipment from [redacted]	326	100%	4 hrs	0,17	03.01.10 21:45	04.01.10 01:45	400	400

25 Oct '09
S S M T W T F

Project: Plug & Abandonment- [redacted]
Date: Thu 23.04.15

Task		Project Summary		Inactive Milestone		Manual Summary Rollup		Progress	
Split		External Tasks		Inactive Summary		Manual Summary		Deadline	
Milestone		External Milestone		Manual Task		Start-only			
Summary		Inactive Task		Duration-only		Finish-only			

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Appendix C

TOTAL E&P NORGE AS

DP-2 ABANDONMENT	Docs No	#665372
	Revision No	00
DP-2 Abandonment Report, Phase 1	Date Created	23.06.2003
Version 0.0	Date Revised	
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17:00	4	BN5	Made up spear assembly. Replaced cup seal on same. Ran and engaged same into 10 3/4" casing. Worked and attempted to pull casing free with 350 t pull and 30 bars pressure on casing. Negative. Increased pull on casing to 400 t and varied pressure on casing fom 0 to 130 bars. Casing moved up a total of 8 cm. A sudden jerk on the casing gave an additional 5 cm. Observed that the wellhead and BOP stack also were moving with the pull on the 10 3/4" casing. Stopped working the casing. Re- checked wellhead and hold-down bolts positions. Ok.
21:00	0,5	BN5	Released 10 3/4" spear, pulled out and racked back same in derrick.
21:30	1,5	B2D	Made up, checked and RIH on 5" DP to 212m with casing cutter for 10 3/4" casing. Cut 10 3/4" casing at 212m according Weatherford instructions. Cutting parameters: 150 RPM, pump pressure 120 bars and torque max 6000 Nm. Pressure dropped off to 8 bars. No indication of casing tension release.
23:00	1	B2D	Checked for flow for 15 mins. Negative. POOH with and laid down 10 3/4" casing cutter.

TOTAL E&P NORGE	CHRONOLOGY	Report No 4 13/05/2003	25/5-A16

Start	Duration	Codes	Operation
00:00	5	BN5	Ran and engaged spear into 10 3/4" casing. Worked stuck casing with up to 350 t overpull and 30 bar pressure on casing. Increased overpull to 400t and pressure to 100 bars on casing. Strech test indicated (250t - 350 t pull = 8 cm strech equal to +- 160m of casing free) It indicates free point at +- 184m RKB. Observed movement of wellhead and BOP stack started again. Stopped working on casing.
05:00	0,5	BN5	Released, POOH and racked back spear assembly.
05:30	1	BN5	Replaced cutter blades in casing cutter and made up cutting assembly for 10 3/4" casing.
06:30	1,5	BN7	Repaired hydraulic leak on pod for BOP annular preventer. Laid down 5" DP from derrick.
08:00	1	BN5	RIH with cutting assembly to 168m. Cut 10 3/4" casing at 168m according Weatherford instructions. Cutting parameters: 150 RPM, pump pressure 110bars. Pressure dropped off to10 bars. No indication of casing tension release.
09:00	1	BN5	Flow checked for 15 min. Negative. Circulated bottoms up. No gas reading
10:00	1	BN5	POOH with and laid down cutter assembly.
11:00	3	BN5	Made up and replaced grapple on spear assembly. Ran and engaged same into 10 3/4" casing. Worked and attempted to pull casing free with max. 400 t pull and max 130 bars pressure on casing. Negative.
14:00	1	BN5	Released 10 3/4" spear, pulled out and racked back same in derrick. Cleared rig floor.
15:00	8	B2B	Installed lower part of milling riser below rotary table. Made up section K-mill assembly for 10 3/4" casing. Function tested section mill - OK. Continued making up section mill BHA with Jar & accelerator, picked up 5 joints HWDP and RIH with same.
23:00	0,5	B2B	Held prejob meeting and SJA with all personnel involved in milling operation and swarf handling.
23:30	0,5	B2B	Started installation of swarf recovering equipment.

TOTAL E&P NORGE AS

DP-2 ABANDONMENT	Docs No	#665372
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DP-2 Abandonment Report, Phase 1	Date Created	23.06.2003
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TOTAL E&P NORGE	CHRONOLOGY	Report No 5 14/05/2003	25/5-A16

Start	Duration	Codes	Operation
00:00	1	B2B	Continued installation of swarf equipment.
01:00	0,5	B2B	Displaced hole to milling fluid.
01:30	1	B2B	Started milling of window in 10 3/4" casing from 212m to 212,4m. Milling parameters: RPM = 120- 150, WOB = 0,5-1,2 t, Pump Q= 2200 - 2400 l/min. Torque = 2000 - 6000 Nm.
02:30	0,5	BN5	Observed mud leaks from Swarf riser. Trouble shoot and stopped leak.
03:00	1,5	B2B	Continued milling of window in 10 3/4" casing from 212,4m to 215,3m. Milling parameters: RPM = 120 -150 RPM, WOB = 1 -3 t, Pump Q = 2000 - 2200 l/min. Torque = 2000 - 8000 Nm.
04:30	0,5	BN5	Plugged off screens of Swarf equipment. Return flow overflowd screen into swarf skip. Stopped milling for sorting out the problems.
05:00	1,5	B2B	Continued milling of 10 3/4" casing from 215,3mtrs to 218mtrs
06:30	0,5	B2B	Circ and clean swarf shaker on Rig floor.
07:00	2	B2B	Mill 10 3/4 csg from 218mtrs to 221mtrs
09:00	0,5	B2B	Backream to 212mtrs to clean up swarf ball.
09:30	0,5	B2B	Continue milling 10 3/4 csg from 221mtrs to 224mtrs observe increase in std pipe pressure.
10:00	1	B2B	Backream to top of cut at 212mtrs and circ out swarf ball.
11:00	4,5	B2B	Cont to mill 10 3/4 csg from 224mtrs to 228mtrs,circ clean.
15:30	0,5	B2B	Clear swarf screens and change out swarf skip (2.6 tons of swarf)
16:00	8	B2B	Mill 10 3/4 csg from 228 to 238mtrs

TOTAL E&P NORGE	CHRONOLOGY	Report No 6 15/05/2003	25/5-A16

Start	Duration	Codes	Operation
00:00	4	B2B	Continue to mill 10 3/4 csg from 238mtrs to 242mtrs,change swarf skip,(2.3 tons and 1ton of swarf from shakers.)
04:00	2	B2B	Back ream to top of cut @ 212mtrs and circ hole clean.
06:00	2,5	B2B	Cont to mill 10 3/4 csg from 242mtrs to 247mtrs
08:30	0,5	B2B	Clear swarf screens and change out skip (2 tons)
09:00	4	B2B	Mill 10 3/4 csg from 247mtrs to 253mtrs
13:00	1,5	B2B	Observe pressure increase,backream to top of cut @212mtrs and clean out swarf.
14:30	1,5	B2B	Mill 10 3/4 csg from 253mtrs to 255 mtrs
16:00	2	B2B	Hold P.J.-S.M. then make connection in swarf handling mode
18:00	4,5	B2B	Continue to mill 10 3/4 csg from 255mtrs to 262mtrs.
22:30	0,5	B2B	Circulate hole clean and work string.
23:00	1	B2B	Hold P.J.S.M. then rig down swarf handling equipment.

TOTAL E&P NORGE	CHRONOLOGY	Report No 7 16/05/2003	25/5-A16

Start	Duration	Codes	Operation
00:00	0,5	B2B	Continue to rig down swarf equipment
00:30	4,5	B2B	P.O.O.H. with milling assy,rack back B.H.A.,lay out mills.Section mill 70% worn.

TOTAL E&P NORGE AS

DP-2 ABANDONMENT	Docs No	#665372
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05:00	1	B2B	R.I.H. w/ jetting sub and jet wash w/head and B.O.P.s of any residual swarf,flush choke and kill lines.
06:00	3	B2C	Make up 400mtrs of 3 1/2 cmt stinger and R.I.H.Change handling equipment and continue to R.I.H. on 5" D.p. to 530mtrs,due to mud U tubing through the pipe displace well to seawater @530mtrs.
09:00	0,5	B2C	Continue to R.I.H. to 640mtrs.
09:30	1	B2C	Circ until clean seawater then Spot high vis pill from 640mtrs to 440mtrs
10:30	1,5	B2C	P.O.O.H. to 435mtrs , rig up cmt std and surface lines @435mtrs and hold a P.J.S.M. prior to cement job.
12:00	1	B2C	Mix and pump surface cmt plug No1 from 435 mtrs to 280mtrs = 6.1 m3 seawater cmt slurry @ 1.98 sg consisting of Cmt class G w/15% microbond E and 145ltrs of CaCL2 and 8ltrs of NF6
13:00	1,5	B2C	Rack back cmt std and pull back to 280mtrs and reverse circ clean.
14:30	1	B2C	Rig up and test cmt lines then mix and pump surface cmt plug No2 from 280mtrs to 166mtrs = 8.6m3 seawater cmt slurry@ 1.98sg consisting of Cmt class G w/15% microbond E and 205ltrs of CaCL2 and 12 ltrs of NF6.
15:30	1,5	B2C	Rig down cmt lines and P.O.O.H. form 280mtrs to 164mtrs and reverse circ clean.Drop wash ball and conventionally circ out same until clean.
17:00	1	B2C	P.O.O.H. with cmt stinger.Rack same rig down 3 1/2 handling equipment
18:00	0,5	B2E	Hold pre job safety meeting on D.P.2 re simops prior to commencement of abandonment operations on producing West cluster.
18:30	1	B1D	Hold pre job meeting and commence to nipple down diverter.
19:30	0,5	B2E	Hold pre job safety meeting on D.P.2 with night crews re simops prior to the commencement of abandonment work on producing West cluster.
20:00	1	B1D	Continue to nipple down diverter and pull overshot.
21:00	2	B1D	Pressure test top drive upper and lower I.B.O.P.s and mud hose to 30 bar and 345 bar while W.O.C.
23:00	1	B2E	Make up 8 1/2 bit and B.H.A. and R.I.H. and tag T.O.C. @ 166mtrs dress off cmt to 170mtrs and weight test same to 10 tons ok.

TOTAL E&P NORGE	CHRONOLOGY	Report No 8 17/05/2003	25/5-A16

Start	Duration	Codes	Operation
00:00	1,5	B2E	P.O.O.H. and rack back tagging B.H.A.
01:30	0,5	B2C	Close shear rams and test surface cmt plugs to 100bar 10 mins ok
02:00	3	B1D	Hold P.J.S.M. nipple down B.O.P.s ,tensioning system and H.P. riser, install hatch covers on well A 16
05:00	3	B2E	Remove bridge to D.P.2.Hold P.J.S.M. prepare Rig for skidding and then skid Rig from A 16 on East cluster over to well A 06 on West cluster.
08:00	11	BN5	Remove top cap and rubber element from annular and clean swarf from same,commence cleaning the rest of the B.O.Ps of residual swarf left over from milling operations.Continue to strip annular,remove operating piston and clean swarf, while pressure testing manifolds on the Rig floor.
19:00	0,5	BN5	Hold pre job safety meeting with night crew prior to commencement of work cleaning B.O.P.s of residual swarf