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Writer: Fredrik Birkeland
Faculty supervisor: Kjell Kåre Fjelde, University of Stavanger External supervisor(s): Hogne Kile, Statoil ASA	
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Abstract

Quote from Douglas C. Nester, COO Prime Offshore LLC: *“P&A obligation is like death; you can try to delay it for as long as possible, but sooner or later it will occur.”*[1]

Many wells on the NCS (Norwegian Continental Shelf) will need to be permanently plugged and abandoned during the next 50 years. In order to do proper planning for these jobs, a good methodology, cost estimation and risk evaluation procedure is needed. Statoil recognizes this need, and from the help of data provided by Statoil and its participation with other major companies worldwide, this thesis has been developed.

This thesis will mainly concern offshore PP&A (Permanent Plug and Abandon) operations on the NCS. The main focus of this thesis is on technological solutions which may lead to better plugging results and less expensive operations. The thesis also covers an overview of rules and regulations, cost and time estimation per Statoil ASA, Conoco Phillips and Oil and Gas UK guidelines. An overview of challenges and risks concerning PP&A operations is also provided.

The work on this thesis has revealed that there are potential for reducing time and cost related to PP&A operations. Some of the elements which may impact PP&A operations in a beneficial manner are:

- New cutting technology
- Alternative to section milling
- Alternative plugging materials
- PP&A vessel modifications

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Table of abbreviations

AFE	-	Approval for Expenditure
APOS	-	Internal Statoil steering document
APR	-	Abandonment Performance Review
ARO	-	Asset retirement obligation
CAT B	-	Category B intervention vessel
CBL	-	Casing Bond Log
CFR	-	Code of Federal Regulations
COP	-	Cessation Of Production
CoPNO	-	Conoco Philips Norway
CPR	-	Completions Performance Review
CT	-	Coiled Tubing
D&W	-	Drilling & Well
DDR/DBR	-	Daily Drilling Report / Daglig Borerapport
ECD	-	Equivalent Circulating Density
ECD	-	Equivalent Circulating Density
GOM	-	Gulf of Mexico
HOCNF	-	Harmonized Offshore Chemical Notification Format
ICV	-	Inflow Control Valve
IMCT	-	Internal Multistring Cutting Tool
IRIS	-	International Research Institute of Stavanger
LCM	-	Lost Circulation Material

LWI	-	Lightweight Intervention
MMS	-	Ministry of Mineral Services (US)
NOKs	-	Norwegian Kroner (Norske Kroner, plural)
NPT	-	Non Productive Time
O&GUK	-	Oil & Gas UK
OCS	-	Outer Continental Shelf (term used on US territory)
OSPAR	-	Oslo-Paris convention
PSA/PTIL	-	Petroleum Safety Authorities / Petroleumstilsynet
REACH	-	Registration Evaluation Authorization and restriction of Chemicals
RSFO	-	Regional Supervisor office of Field Operations
S.G	-	Specific Gravity – Gravity compared to sea water (1,03 S.G)
SINTEF	-	(Selskapet for INdustriell og TEknisk Forskning ved NTH/NTNU)
SNS	-	Southern North Sea
UK	-	United Kingdom
UKCS	-	United Kingdom Continental Shelf
US	-	United States (of America)
USIT	-	Ultra Sonic Imaging Tool
VDL	-	Variable Density Log
WBE	-	Well Barrier Element
WBEAC	-	Well Barrier Element Acceptance Criteria
XMT	-	Christmas Tree (sophisticated valve system)
PSA	-	Petroleum Safety Authorities

Introduction

1st hypothesis, “H₀”: There exists a potential to reduce the time and cost related to FF PP&A (Final Field Permanent Plug & Abandon) campaigns.

The need for a good methodology regarding the cost estimation, risk evaluation and performance of FF PP&A jobs is great. This need increases steadily, seeing that more and more wells will need to undergo this procedure during the next 50 years, especially on the NCS (Norwegian Continental Shelf). Up until now, there have been performed a small amount of this kind of job on the NCS. This is due to the fact that the development of wells on the NCS didn't start out until the 1970's. Quite a few of the wells drilled in the 70's, 80's and 90's are still producing, but in the coming 50 years, they will need to be permanently plugged and abandoned. Statoil recognizes this need, and has therefore seriously started to scrutinize the current methods and potential future solutions related to this procedure. Up until last year, estimates of the costs associated with PP&A operations have been prepared by several different methods:

1. Projecting costs based on experience. That is similar operations which have been executed earlier.
2. Step by step operational time estimates that combine day rates with service provider costs.
3. Earlier it was common to come up with “a hunch” or a guess.

There are many challenges related to the estimation of costs of these operations, and they will be discussed in the “Evaluation of time and cost estimation related to FF PP&A” chapter of this thesis. An overview of the current technology, future technology and both governmental and self-imposed regulations will also be covered.

The goal of PP&A operations is to properly plug and abandon wellbores such that hydrocarbons and water sources are isolated from flow both presently and in the future. Methods and processes which effectively achieve these goals at lower costs are constantly being developed and evaluated. In addition to saving capital, the drilling

capacity will increase if the time required to perform decommissioning and permanently plug and abandon wells are reduced. This in turn will return more wells drilled, more production and ultimately maximizing the company's stock market value.

This thesis mentions some of the possible future solutions which can have the potential of making future PP&A operations less time consuming and expensive. Several new techniques of performing the different elements in a PP&A operation have been developed. Amongst these is the new cutting technology which utilizes abrasive water jetting systems[2]. The use of LWI vessels which have the ability of cutting conductor, surface casing and wellhead is an improvement compared to the conventional way which is the use of cutting knives or explosives. There has also been developed a tool which enables well abandonment of wells with bad primary cement job, without the need for section milling. This has the potential of saving days in PP&A operations. In addition to this, there has been developed at least two new exciting plugging materials. These are called Sandaband® and ThermaSet®, and preliminary results indicate that they may be better suited to PP&A applications than cement.

The development of plugging materials with better long-term integrity than cement is important. This development may increase the quality and further reduce the time of future PP&A operations. In addition the development of lighter and less expensive vessels which have the capability of performing more elements, or all the elements, of PP&A operations will have the potential of reducing costs even further.

Improved operations could be achieved if cement bond logging tools that can log through several casings and cement layers were developed. Such tools could have the potential of altering the method of plugging operations and improve the verification process of already in-place casing and cement. CAT B vessels are being developed, and they have the potential of joining the PP&A vessel fleet in combination with LWI vessels. This will allow greater operational flexibility.

For an overview of the workflow with this thesis, please consult Appendix A.

1 Theory

This section will cover the basics of PP&A operations, needed to understand the rest of the thesis. Amongst this is an overview of the operational procedures, some of the legal regulations and requirements and new technology related to PP&A operations. In addition this section provides an overview of an oilfield, an oil well prior to a PP&A operation and how an oil well should look after a PP&A operation has been performed.

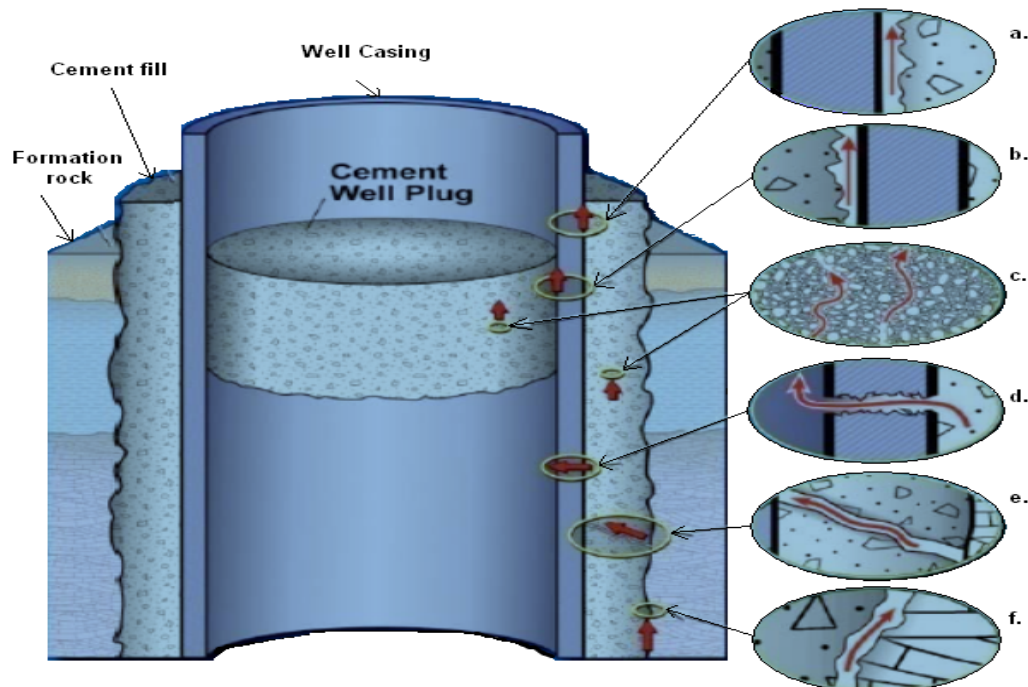


Figure 1: Well with cement plug in it. Source: SINTEF presentation about ThermaSet®.

Common practice to set PP&A plugs is to use cement as plugging material, and put it inside the well casing. Supposed that the cement outside the casing is of satisfactory quality, this method is the conventional method of performing well abandonment. However, as Figure 1 indicates, there are several ways in which cement may fail. A), B) and F) show how poor bonding between cement and casing / formation can lead to creation of possible leak paths. C) Shows how hydrocarbons can mitigate through the permeable cement. D) Illustrates cement failure due to deterioration of well casing and f) shows how cement can fail during hardening, due to migration of gas. Chapter 1 and 2 in this thesis will discuss some methods that may mitigate the problems illustrated in Figure 1.

1.1 Build-up of oil and gas fields

A major scale hydrocarbon field can consist of many different facilities used for extracting hydrocarbons. Amongst these are drilling rigs, production rigs, subsea templates (well templates beneath a floating rig/production facility) and satellites (well templates which are positioned far from the production facility). Figure 2 shows how some of the major oil and gas fields of Statoil are configured.

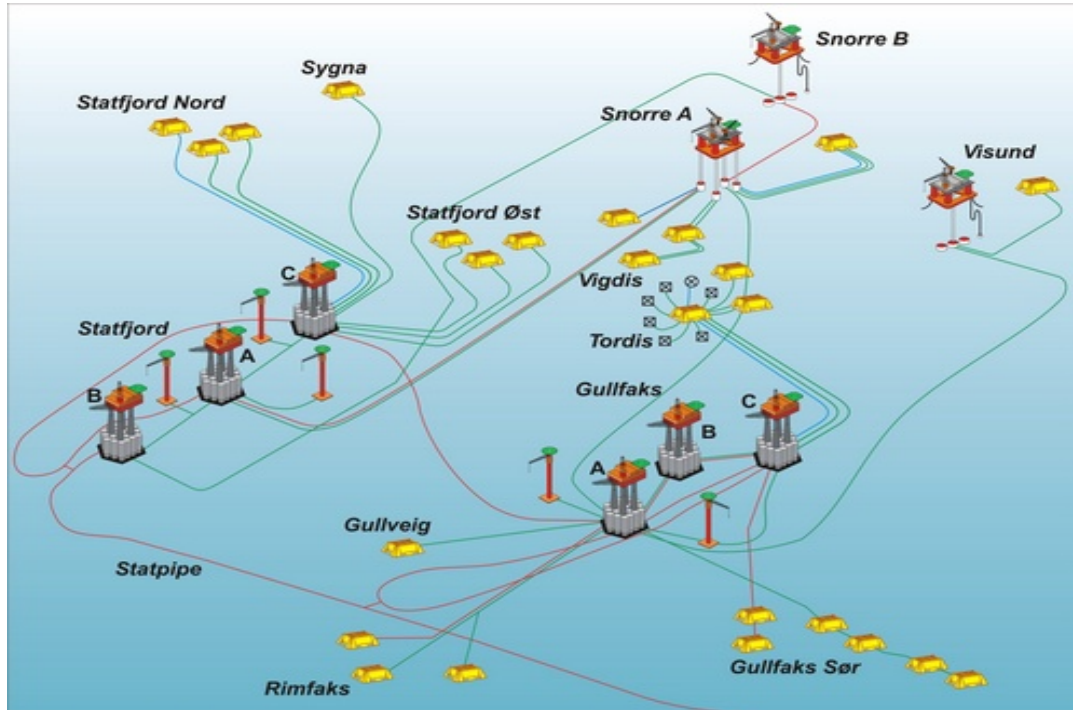


Figure 2: Overview of some of Statoil's major oil and gas fields. Source: Norsk Oljemuseum.

As can be seen, the fields consist of large concrete platforms in combination with subsea templates and satellite wells. The wells produce hydrocarbons, and when they stop producing hydrocarbons, they have to be permanently plugged and abandoned. In many instances, it is common practice to permanently plug and abandon the main bore and reservoir section of the well, to allow for subsequent drilling of a sidetrack from the same slot. This thesis will mainly focus on methodology development, cost and time estimation and risk evaluation of wells that shall be completely permanently plugged and abandoned.

1.2 Configuration of a well prior to and after PP&A operation

According to one of the most common industrial standards in Norway, NORSOK D-010 [3], the definition of “permanent abandonment” is: “well status, where the well or part of the well, will be plugged and abandoned permanently, and with the intention of never being used or re-entered again”.

As an example, a perforated well, prior to PP&A, will be presented with corresponding typical well schematic. In this particular instance, the tubing is left in hole.

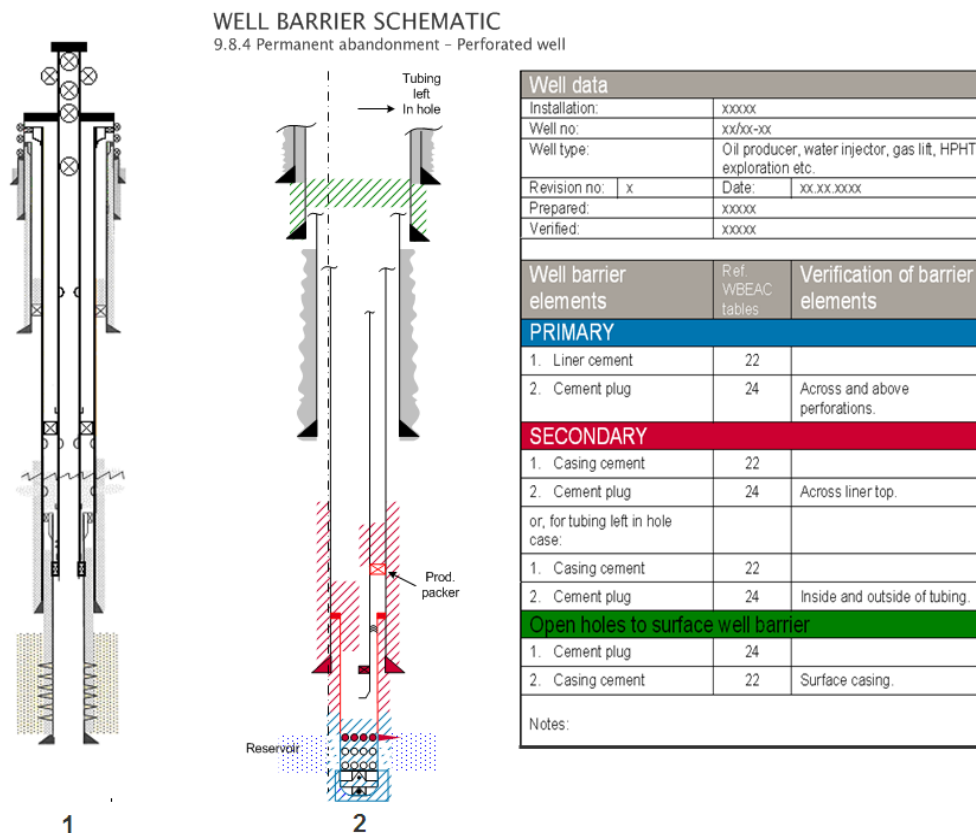


Figure 3: Cased and perforated well prior (1) and after (2) PP&A operation. Source: APOS.

(1) & (2) in Figure 3 shows how a well looks like prior and after a PP&A operation has been performed. The barrier configuration in the already PP&A'ed (2) well is highlighted with colours, and a corresponding table with legends is given to the right. It is common practice to remove the tubing even though it does not have control lines attached to it. The reason for this is that if the tubing is cut above the production packer and left in hole, it may jeopardize the plugging operation of the reservoir. This will be discussed more in the “Cut and leave tubing in hole” section of this thesis.

1.3 Current operational procedure for PP&A

When a well has reached the end of its lifetime, it is necessary to permanently plug and abandon it. This is to ensure that the environment never will be exposed to hydrocarbons from that particular well, and when the platform/rig itself ultimately needs to be removed, it is required that it leaves no “visible” traces or hindrances of further practical use of the (offshore) area.

Governmental regulations state that “For permanent abandonment wells, the wellhead and the following casings shall be removed such that no parts of the well ever will protrude the seabed. Required cutting depth below seabed should be considered in each case, and be based on prevailing local conditions such as soil, sea bed scouring, sea current erosion, etc. The cutting depth should be 5 m below seabed. No other obstructions related to the drilling and well activities shall be left behind on the sea floor” [4]. These regulations imply that there should be no traces left on the seabed after the PP&A jobs are finished. The well abandonment procedure may vary much from well to well, but it can be summarized in some general main steps which will be discussed further in the following subsections:

- PP&A vessel mobilisation
- Get everything in place and ready (Derrick etc)
- Kill the well
- Pull the tubing (and lower completion)
- Plug the reservoir – prevent cross-flow and flow in the well
- Cut and pull the intermediate casings, plug 1-3 different depths depending on design of well and its conditions
- Set the top plug(s)
- Remove upper part of surface casing, conductor (and wellhead)
- Rig / derrick demobilisation

For a specific example on a well abandonment program, see Appendix B.

1.3.1 PP&A vessel mobilisation

The vessels needed to perform the P&A operation needs to be mobilised. The section “Proposal to different vessel combinations for PP&A” presents some ideas of which vessels that could be needed in the PP&A operations. Good planning is necessary in this phase, so that it is ensured that the PP&A vessels arrives to the specific location at the correct time, and has capacity to stay there until its job is done. Mobilisation of vessels may take from days to weeks, depending on how far they have to travel to get to the site. If it is decided to use a platform with drilling rig / derrick that is already in place, it is necessary to skid the derrick in place and get the systems ready.

1.3.2 Get everything in place and ready

If a platform with rig / derrick which is already in place is decided to be used, the derrick needs to be skidded in place. This may take some time (minutes to hours) depending on, amongst others, how far it has to skid and the weather conditions. All equipment needed for the operation has to be accounted for and made ready. When the operation is started, it should not be necessary to wait for missing equipment.

1.3.3 Kill the well

Before the well can be entered for PP&A purposes, it is necessary to kill it. This is done by replacing the well-fluid with a heavier fluid. Depending on volumes, length of well and well path configuration, this takes a certain amount of time. Problems may occur during this phase of the PP&A operation. One example is that when bullheading the reservoir, it may fracture. This will cause losses of drill fluid, and difficulty in establishing control of the well. It is therefore necessary to have contingencies if this problem arises. Proper LCM (Lost Circulation Material) and enough kill fluid should be available on rig.

When the well is killed, meaning that it is in overbalance, the XMT (Christmas Tree) can be nipped down. After this is done, the BOP (Blow Out Preventer) is nipped up.

After the well is killed, it is common to perform a diagnostic logging run in the well, to assess the condition of the downhole equipment and environment. The quality of this logging and the interpretation of the logs are of utmost importance. This is discussed further in the “New Technology” chapter.

1.3.4 Pull the tubing (and lower completion)

Pulling of tubing is a heavy operation. This is currently an activity typically done by a rig (workover vessel) due to the limiting lifting capacity of lighter intervention vessels. In some cases where it has been deemed impossible to pull the tubing, it has been cut and left in the reservoir with plugging material on the inside and outside. The lower completion can be pulled if wanted, but it is in many instances left in the hole.

1.3.5 Plug the reservoir and potential cross-flow

The reservoir needs to be plugged. According to the steering documents in Statoil, "APOS" (Arbeids og Proessorientert Styling), a permanent barrier shall have the following properties:

1. Impermeable
 2. Long term integrity
 3. Non-shrinking
 4. Ductile – able to withstand mechanical loads/impact
 5. Resistance to different chemicals / substances (H₂S, CO₂ and hydrocarbons)
 6. Wetting, to ensure bonding with steel.
- Open-hole cement plugs can be used as a well barrier between reservoirs. It should also be used as a primary barrier, if practically possible.

These properties are in compliance with the industry standard, NORSOK D-010.

There are different methods of achieving these objectives. One may for example vary the setting method of the plug and the plugging material.

It is not necessary to remove the downhole equipment as long as the integrity of the well barriers is achieved.

According to NORSOK [3], when tubulars from the well completion is left in the hole and permanent plugs are installed through and inside the tubular, their position and integrity should be tested and verified by reliable means.

1.3.6 Log, cut and pull intermediate casings and set isolation plugs

If the casing is adequately cemented, a plug can be set inside the casing. However, the casing itself is not an acceptable WBE (Well Barrier Element) unless it is supported by cement, or a plugging material with similar functional properties (inside and outside). See Figure 4. Certain wells may require cutting and pulling of intermediate casings. This is conventionally done by running a cutting tool with cutting knives in the hole. This tool rotates, and cut the casing.

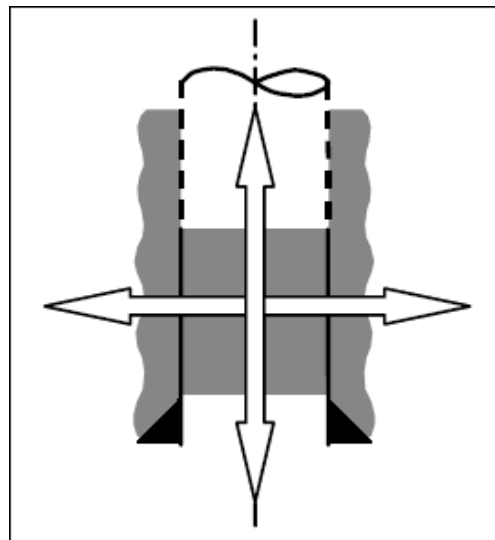


Figure 4: Cross-sectional cement plug [3].

1.3.6.1 Section milling

As can be seen from Figure 4, the casing is supported by cement on the outside. In many cases, the cement on the outside of the casing is either of a very poor quality, or entirely missing. In those cases, it is necessary to perform an operation called “section milling”, which implies that a steel milling tool is used to mill away the casing in the desired interval. An example of a tool like this is depicted in Figure 5. This technique is challenging to perform, and in some cases it is not possible to perform. The swarf that is generated when the steel is milled has a high density. In order to clean the hole during operations, the milling fluid has to be able to carry the swarf out of the hole. Some of the methods to achieve hole cleaning, are to increase the viscosity of the mud, increase the weight of the mud or by increasing the pumping rate. If the viscosity of the mud or the pump rate is increased, it leads to more friction in the path of where the mud flows. This friction induces a friction pressure loss which must be compensated by the pump pressure on the rig in order to keep the desired pump rate. This will in turn yield a higher ECD (Equivalent Circulating Density), which in a simple way can be described as the mud density that the bottom hole area experience. In addition the swarf has a tendency to ball up (“bird nest”) on the way to the topside at places where the annular velocity is low. Typical places for this to occur are in the liner hanger, BOP and in the riser.

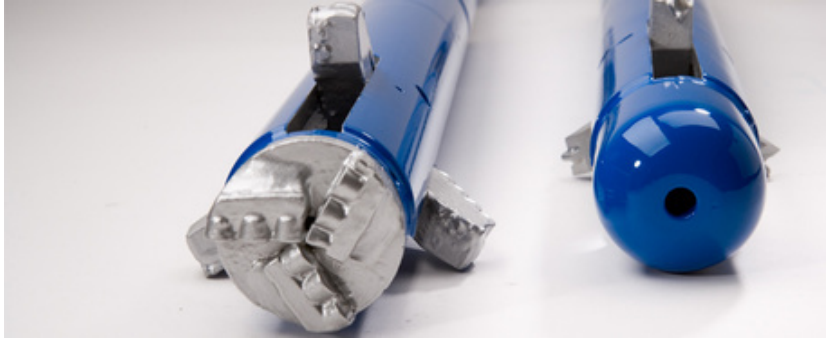


Figure 5: Casing milling and under reaming tool. Source: Baker Hughes.

1.3.7 Set top plug(s)

The main wellbore and open hole to surface plugs, have to fulfil the same requirements as the reservoir plug. When the casing is supported by good cement, it is sufficient with a cement plug in the casing. In order to find out if the casing is properly cemented on the outside, a CBL and a USIT may be run. If it is set with a mechanical packer as foundation, it has to be at least 50m according to NORSOK D-010 and APOS. When a plug is set on a mechanical foundation, it means that a mechanical plug (e.g. a bridge plug) is set in the casing. Then a work string that pumps cement is run in the hole to the depth of the mechanical plug, and cement is pumped. This cement displaces the overlying mud column.

1.3.8 Removal of the upper part of surface casing, conductor and wellhead

There are several ways to perform this operation. The conventional way is to perform this operation with cutting knives. If the proper applications are sent, the cutting operation can be performed by the use of explosives. The use of explosives introduces a certain HSE risk and strict work procedures, and should therefore be avoided if possible. The chapter “New Technology” explains how this part of the operation can be performed with abrasive water jet cutters. NORSOK states that the casings shall be cut at least 5m below the seabed, and APOS states that it shall be cut at least 2-5m below the seabed when removing the wellhead. If the surface casing, conductor and wellhead are cut less than 5m below the seabed, it shall be covered in such a manner that it poses no obstruction to other use of the ocean (e.g. fishing activities).

1.3.9 Decommissioning of surface and sub-surface installations

When all the downhole equipment, wellhead and, if relevant, templates for all wells are removed, the rig itself needs to be removed. This is called decommissioning and is, on the NCS and SNS, to a large extent governed by the OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations (Oslo-Paris convention)[5]. A comprehensive summary of these regulations are given in the rules and regulations chapter.

1.4 Possible vessels combinations for PP&A


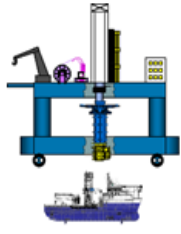


LWI	LWI & CAT B(CT)	LWI & RIG/DERRICK	RIG/DERRICK
			
LWI perform diagnostic WL-run and kills the well (present)	LWI perform diagnostic WL-run and kills the well (present)	LWI perform diagnostic WL-run and kills the well (present)	Kill well (present)
Install perm. barrier plugs* (future)	LWI installs perm. barrier plugs*, CAT B perform heavy workover like pulling of casing, (future)	LWI plug the reservoir*, cut tubing and pull XT (future)	Plug the reservoir, pull tubing, XT (present)
Pull XT (present)	CAT B pull XT (future)	Rig pull tubing, cut and pull casing(s) and set isolation plugs (present)	Cut and pull casing(s) and set isolation plugs (present)
Cut and pull WH (present)	CAT B cut and pull WH (future)	Rig cut and pull WH (present)	Cut and pull WH (present)

Figure 6: Suggested combination of PP&A vessels.

*Current LWI vessels can install mechanical plugs that act as foundation for cement plugs already. A tool that enables cementing from other vessels than rig is under development, but it is of a sensitive nature, so it will not be discussed in this thesis.

1.5 New technology for PP&A operations

The need for new technology which has the potential of achieving proper PP&A jobs at a reduced cost has been recognized by the service providing industry. There are several tools and materials being developed with this in perspective, and some of them are presented in this section.

1.5.1 Cutting technology

Due to the need of safer and more efficient cutting technology than conventional tools, like cutting knives and explosives, the development of abrasive water jet cutting started. This is based on the principle of a thin, high pressure jet of water mixed with an abrasive substance. This abrasive water jet has the ability to cut through steel in a very smooth and efficient manner. The cutting profile is illustrated in Figure 7:



Figure 7: Cut of casing and cement with abrasive water jet technology.

According to the service provider, NCA (Norse Cutting and Abandonment) [2], the advantages of abrasive water cutting on a subsea wellhead are:

- *“Can be operated from a vessel and does not require drill pipe or work string*
- *Cutting and recovery of wellhead in one deployment*
- *No need to reposition vessel during the operation*
- *The IMCT (Internal Multistring Cutting Tool) produces a clean and even cut for easier and safer recovery and handling of the wellhead at the surface*
- *Eliminates hazardous handling of drill pipe or explosive charges*
- *Cutting is insensitive to compression in casing and works on centric or eccentric casing, with or without cement in annuli*
- *Superior cutting speed – typically 1-4 hours efficient cutting time or 8-12 hours roundtrip time deck to deck*
- *Stand alone, rigless surface package*
- *Computer based control and monitoring system”*

This technology has the capability of cutting through a complete set of tubings, i.e. production liner, 9 5/8” intermediate casing, 13 3/8” intermediate casing, 20” surface casing and 30” conductor in one run. The IMCT is equipped with two inflatable packers which isolate above and below the cutting nozzles. After setting of these packers, the fluid between the packers is evacuated. This greatly enhances the cutting ability, as the abrasive water jets cuts better if it is air inside the tubing than if a liquid is present. The limitations of this technique lies in the range of depths in which it is applicable. At too great water depths, the hydrostatic pressure outside the tubing is so large that the cut is rendered less effective.

A sample image of a cut and retrieved tophole casing section is showed in Figure 8.



Figure 8: Multiple casing cut

Results from operations with the IMCT cutting from 7" casing through 30" conductor is in the time range 1-4 hours. From the Subsea Wellhead Retriever leaves the deck of the vessel with the IMCT, it takes typically 8-12 hours until the wellhead is safely landed on deck.

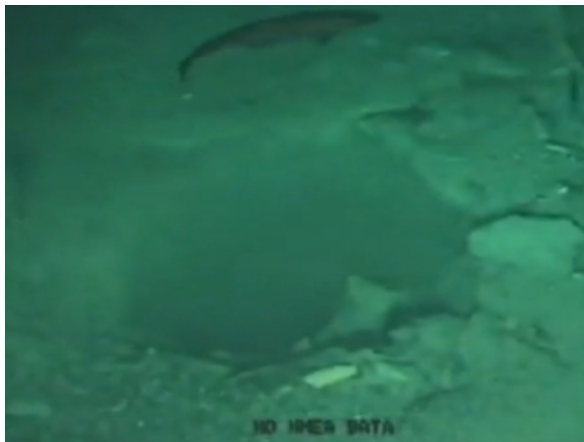


Figure 9: Abandoned well, NCA job on Troll A. Source: Decommissioning Offshore.

Figure 9 shows how an abandoned well looks like after the wellhead, conductor and surface casing is cut and pulled.

1.5.2 Development of a tool that eliminates the need for section milling

HydraWash™ is a tool that enables plugging of wells with a poor primary cement job, without the need of performing section milling. This system consists of a jetting tool and a cement stinger and a tool called “Archimedes™”) which are run in hole as one tool. Full circulation is possible when running in hole. The jetting tool and the cement stinger are placed above a set of TCP (Tubing Conveyed Perforation) guns.

First the casing is perforated. Then a ball is dropped inside the tool, which closes off the bypass channels. The perforated interval is subsequently washed and cleaned by the jetting tool. This washing continues until desired pump rate is achieved. Finally, a larger ball is dropped to activate the hydraulic release system that separates the HydraWash™ Jetting Tool from the cement stinger and the Archimedes™ tool, thus enabling pumping of plugging material. Once the plugging material is pumped, rotating of the Archimedes™ tool is started while slowly pulling the workstring up to above TOC depth. Then the plug can be tested according to the operator’s procedure prior to pulling out of hole.

For the interested reader, a detailed operational procedure is provided in Appendix C.

1.5.3 Verification of barrier plugs – new technology

Understanding the downhole conditions is very important when entering a well to perform a PP&A operation. It is important to know the status of the casing integrity, the quality of the annular cement and the bonding between cement / casing and cement / formation. All these factors are connected to the barrier status of the well, and will greatly impact the planning and execution of a PP&A operation.

When the time comes to verify the barrier plugs, it is important to use the correct tools. A conventional CBL will not guarantee hydraulic isolation. A USIT log will give a better indication of hydraulic isolation. New technology for verification of barrier plugs is a tool which combine Calliper log, USIT, CBL and VDL (Variable Density Log). The VDL penetrates the downhole cross-section enough to give some indication of the bonding between cement and formation. CBL can give valuable information about the bonding

between cement and casing. USIT measures several parameters: Acoustic Impedance, cement bonding to casing, internal radius of casing and casing thickness. Usually, an Ultrasonic-CBL combination yields satisfactory results in standard class G cements. But if a lightweight cement is used, or if there are thick casings, the recently developed combination of Calliper log, UIST, CBL and VDL will give a tubular and solids evaluation plus accurate mechanical radius data.

Other benefits of applying such a combination tool is, according to a presentation on the by P.Estrada of Schlumberger at SPE's 3rd European Well Abandonment Seminar 29th March 2011 in Aberdeen:

- Eliminates need for 2 runs (when both bonding properties and mechanical properties of casing is needed)
- Eliminates effect of dirty borehole and the effect of rugose tubular surface on Ultrasonic radius (use multifinger calliper data)
- Comparison of two entirely different measurements for greater confidence
- Absolute inner radius measurement and qualification of small features

1.5.4 Recently developed plugging materials

The development of materials that are of proper quality and of reduced cost compared to cement could have major impact on PP&A operations. Even if the price of the material itself is more expensive than cement, its use may be justified by reduction in time to place it or by the means of higher quality.

This thesis will cover two different alternatives to cement. One is called "ThermaSet[®]" and the other called "Sandaband[®]".

1.5.4.1 ThermaSet®

ThermaSet® is an alternative material to cement as a plug in PP&A applications. It is a polymer based resin which is triggered to set thermally. After the diagnostic run is made in the beginning of the abandonment operation, temperature is logged through the wellbore. This information will render the engineers capable of setting the ThermaSet® plug at the desired depth. The resin is a fluid when being pumped, and its properties can be adjusted in numerous ways. The range of viscosity is great, and its density ranges are of even greater importance. The density can be adjusted from ca. S.G (specific gravity) 0.65 to S.G 2.5 by using different fillers. If a low density is required, the filler material will be hollow glass balls. And if a high density is wanted, solid glass balls or even Micromax (very small-sized metal particles) can be used as filler. In addition it requires no other pumping equipment than the standard cement pumping equipment which is usually available on rig. It can be pumped through the MWD, motor and drill bit. Once the plug is thermally activated to set, it hardens. This curing may take from 15 minutes to 2 days, depending on the wanted and needed design. When it is hardened, it completely changes the properties, so that it is ideally suited for the downhole conditions in which it is supposed to stay for eternity. One of the properties which make it ideally suited for downhole applications is that it does not shrink during curing.

Properties	ThermaSet®	Well Cement
Water permeability	<0,5 mD	1600 mD
Compressive strength	77 MPa	58 MPa
Flexural strength	43 MPa	10 MPa
Failure flexural strength	1,9%	0,32%
E-modulus	2240 MPa (Standard temperature)	3700 MPa
Tensile strength	60 MPa	1 MPa
Temperature range	3 – 150 °C (200°C – under testing)	N/A

Table 1: Some of the mechanical properties of hardened ThermaSet®

One of the greatest challenges service companies face when introducing new technology in the petroleum industry, is the reluctance to try something new. Even though this is a product which has been thoroughly tested (Chems II, HOCNF, REACH, ISO – V3 [IRIS], Long term integrity test under 500bar and 130°C in separate environments of crude oil, methane H₂S and CO₂ – [SINTEF]), it will take time for the industry to adapt it. CoPNO has tried this product in six wells with great success, and maybe an era where viable alternatives to cement is dawning. The development of new materials will be exciting to monitor, and hopefully the industry will find a better way to permanently isolate the downhole environments from whence modern day societies have gathered the black gold in their constant quest for wealthiness. One of the issues concerning new materials for PP&A applications is that there may be no established ways to test it. This calls for the need of new tests which can certify materials in accordance with NORSOK D-010 requirements.



Figure 10: Liquid ThermaSet.

1.5.4.2 Sandaband® [4]

This is a non-consolidated sand slurry with a wide particle distribution. This slurry has been used with success on the exploration well 25/8-17 “Jetta” and several other fields, but due to discretion they will not be mentioned. Benefits experienced from the use of this slurry which is impermeable and gas tight:

- The material, of which the plug is made, is chemically non-reactive, and due to its nature, it will remain effective “eternally”. This means that it will not experience subsequent fracturing or volumetric shrinking. The reason why it cannot fracture, is because of its Bingham-Plastic properties; when the shear forces exceeds its strength, the material starts to float and shear forces are reduced below the yield strength, causing the plug to reshape.

This plugging material consists of ca. 25-30% liquid and 70-75% solids by volume. The key issue with this type of material is the pumpability. In order to get it pumpable, the particle size distribution needs to be very carefully adjusted.

Another important point for the stability of the slurry is that all the solids particles are in contact with other solids particles. The liquid is just coating the solid particles, and is not a substance which the particles are “submerged” in. This means that the solids move relatively to each other after the material is placed in the well, and no segregation will occur.

The wide particle distribution from 0.1 µm to 2500 µm causes the material to effectively bridge off at the mouth of large fractures, and is therefore ideally suited to LCM in drilling applications as well.

Operationally it is important to be aware of the plugging properties of the material, as it will typically bridge off holes smaller than 2 cm (3/4”) in diameter. This may also sometimes prevent the material from being used in narrow annuli, where for instance the clearance between the OD of a downhole safety valve (DHSV) and the production casing can be very small.

Another important operational issue with this material is that it needs a solid foundation to rest upon. The specific gravity of this material is ca. 2.15 s.g. and this basically implies that it will sink if placed on a fluid column. This could be a mechanical packer, or it could be set in combination with other plugging materials like cement or ThermaSet®. The material itself is gas tight, the pressure the Sandaband® plug is designed to control should be exceeded, it would lift the Sandaband® plug out of the well. Therefore the Sandaband® plug is always designed to control at least virgin formation pressure in a permanent abandonment situation. Alternatively, a cement plug or ThermaSet® plug may be used as a cap for the Sandaband® material. Even though ThermaSet® is almost six times the failure flexural strength of cement, one may never know how mother earth changes in the distant future. Sandaband® has a superior ability to change its shape according to the downhole environment, and therefore a combination with Sandaband® and other plugging materials is highly recommended.



Figure 11: Sandaband® Rig-up. Source: Embla Post-job presentation by Conoco Phillips

The time spent on the 25/8-17 “Jetta” operation was so much less than for traditional plugging operations, that this time saved paid the cost of the operation itself. This is amongst others due to the fact that there is no need to tag TOC, so there is no need to wait for the cement to cure. This may result in 8-12 hours of rig time saved per plug [4]. In addition the price of the Sandaband® slurry is slightly more expensive than conventional cement (Portland G class cement) used in well abandonment scenarios.

Figure 11 shows the rig-up of a Sandaband® operation. This rig-up requires quite much space, depending on the volume of slurry that is needed.

Figure 12 illustrates how the Sandaband® slurry looks like and how it reshapes when the shear strength is exceeded:



Figure 12: Sandaband® Source: Embla Post-job presentation by Conoco Phillips.

This “re-shaping” property makes Sandaband® ideally suited to fulfil the requirement of “eternally lasting”.

2 Challenges and risks related to PP&A operations

This chapter will cover challenges and risks related to PP&A operations. This is a huge area, with a multitude of issues to address, and some of them will be elaborated in this section.

2.1 Challenges related to PP&A operations

In order to achieve a more efficient P&A operational approach, there are several challenges the industry will face during the years to come. Some of these challenges will be addressed in the following subsection, and some of them are to a large extent based on a presentation made by British Petroleum at the ITF Theme day 1st July 2009 [6]. These challenges have also been addressed and recognized by other forums.

2.1.1 Removal of control lines / gauge lines

Introducing wells with intelligent configurations brought along a problem concerning the future well abandonment. If a cement plug covers an interval of the tubing which has control lines attached to it, these control lines can have the potential to create micro annuli and leak paths. Therefore it is a requirement in the UK and Norway, that if the control lines that go to deep set sensors could end up constituting a part of the permanent barrier, they need to be removed. The only way of doing this, and verify that it is done, is to remove the entire tubing on which it is attached. This requires a lot of time and heavy equipment, thus making it an expensive part of the PP&A operation. If a viable way of cutting these lines, and verify this, were developed, the operation would be simplified. If cutting and pulling tubing could be eliminated from the PP&A operation, it would save much time and resources.

2.1.2 Cement in A, B and C annulus

If a good means of placing cement in the A, B and C annulus, as depicted in Figure 14, with the completion tubing in place were developed, the challenges surrounding the already performed cement jobs in the 13 3/8" & 9 5/8" (intermediate) casings may be reduced. If it is found to be impossible to verify the cement quality in the intermediate casings, the typical method to establish new and proper cement in these sections has

been to perform a time consuming and complicated section milling operation followed by a cement plug that covers the entire wellbore laterally. There are arguments to avoid this section milling operation:

- Time consuming and thus costly
- Not always possible to perform due to the high ECD (as mentioned in the Sectuib Milling subchapter). Sometimes the window between fracture pressure and pore pressure is so narrow that the ECD seen while section milling, would lead to fractures in the formation.
- HSE benefits: No problems with waste and handling of downhole equipment (completions, tubings etc)

Currently under development is an electric WL tool that enables perforation and setting of an epoxy based plugging material in the A, B and C annulus. The epoxy is thermally set, and viscosity can be adjusted over a wide range, to ensure that it does not sink when placed on a liquid column. This tool is being developed by the AGR-group, and is called CannSeal™[7]. This epoxy material is preliminary meant as a back-up or support for other plugging materials, but if tested properly and verified, it may be designed as primary plugging material in the future.

The tool has the ability to carry 40-80L of epoxy, depending on the length of the tool. It can inject at a rate of ca. 4L/min with a differential pressure of 200bar. A pilot well, where this technology will be field tested, is due Q3 2011.

2.1.3 The use of wire line to tag and verify permanent barrier plugs

Permanent PP&A operations are in need of a good method to tag and verify the placement and quality of permanent barrier plugs, where CT or jointed pipe is not available. This would enable LWI vessels to perform even more parts of the PP&A operations.

2.1.4 Determination of TOC (Top of Cement) by the use of pressure monitoring

In some cases it is not possible to get a tool down in the well for tagging the material. This could be in wells where subsidence and other geologically driven mechanisms result in collapse of the tubing. This is in many cases so bad that it would not be possible to pass the obstructions, even with WL equipment.

2.1.5 Circulating (cement) in a pressurized well with LWI vessels

There is an ongoing project concerning the development of a method for circulation of cement in a pressurized well with LWI vessels. With some modifications to the set-up for WL, which is commonly used by LWI vessels, circulation of cement in pressurized and live wells could be allowed. The author of this thesis has gotten familiarized with the development of a technology which enables this. But due to the sensitive nature it will not be described in more depth in this thesis [8].

2.1.6 Plugging material selection

There exist a multitude of other suggestions to plugging materials. Amongst these is the AGR group's CannSeal, which is an epoxy based sealing material. According to their website, this material can be placed both in open annulus and in gravel proppant packs [9]. Due to the focus of this thesis, this plugging material has not been pursued any further as the thesis has already covered two alternative plugging materials. Even more alternatives of potential plugging materials are presented below (Jules Schoenmakers [10]), and the reader is encouraged to investigate this on his/her own:

- Cements and ceramics (setting)
 - o Porous, e.g. Portland Class H and G cement
- Grouts (non-setting)
 - o Porous, e.g. sand or clay mixtures (Sandaband®)
- Polymers thermal-setting and composites
 - o Not porous, e.g. resins including fibre reinforcements (ThermaSet®)
- Polymers elastomers and composites

- Not porous, e.g. silicon rubbers including fibre reinforcements
- Formation
 - Not porous, e.g. shale, clay or salt
- Gels
 - Not porous, e.g. bentonite gels, clay gels, polymer gels
- Glass
 - Not porous
- Metals
 - Not porous, e.g. steel, alloys, bismuth

2.2 Solutions to PP&A challenges

As mentioned earlier in this thesis, there exist many challenges concerning PP&A operations. This section will cover some of the solutions which have been developed to face these challenges.

2.2.1 Potential solution to control lines issue

There are potential remedial methods to this problem. One of them is to develop permanent plugging material which has the ability to shift and reshape, as the control lines deteriorate. This would mean that when the control lines deteriorate, the plugging material would reshape and fill the created holes. Another way of approaching this problem is to mechanically cut the control lines. Cutting could be done by using cutters or explosives (perforations). This would open them for circulation from topside. Subsequently a sealant or ever-lasting plugging material could be pumped inside the control lines. With a sealant on the inside, and a reshaping plugging material on the outside, the potential of creating micro-annuli or leak paths is removed.



Figure 13: Control lines externally clamped to the tubing.

Conceptual solution (1):

1. Punch ICV (Inflow Control Valve)
2. Gun creates leak in control lines
3. Inject sealant in control lines

Conceptual solution (2):

1. Cut tubing and control lines (Sindex cutter)
2. Inject sealant in control lines

As can be seen from Figure 13, it is easy to visualize how filling cement around this tubing, with its exterior configuration, could potentially create small voids and micro annuli around the control lines. However, if the tubing were submerged in water, one could easily imagine the water filling every possible void and not creating micro annuli. There exist plugging materials which have almost the same properties as water whilst in fluid form. An example of this is ThermaSet®. Figure 10 shows liquid ThermaSet®.

2.2.2 Potential solution to the cement in A, B & C annulus issue

When BP set out to abandon the wells at the Miller Platform [11], they sought for a means to control the costs. They identified that it was necessary to perforate through multiple casings, in order to circulate cement in all the annuli such that a cross-sectional cement plug could be obtained. The problem with this operation is that it is strongly recommended not to perforate through to open hole, as this may cause direct communication with the formation. This could ultimately render the placing of the cement plugs impossible due to losses. Therefore they set up a project with Expro North Sea for providing selective perforations that would perforate only through the next immediate casing. The configuration of perforating guns can be found in [11]. BP has in this reference avoided to explain how they actually performed the operation, but a suggestion could be as follows:

1. Perforate the A annulus above the mechanical packer and at a desired height above (ca. 50 - 150 m) in order to establish circulation.

2. Place the cement plug in the A annulus and wait for it to settle.
3. Perforate through the set cement and the next casing at the desired heights and in order to place cement in the B annulus.
4. Place the cement in the B annulus and wait for it to settle.
5. Dump cement on top of mechanical packer
6. Wait for cement on top of packer to settle
7. (Verify the quality of the cement plug that stretches across the entire wellbore)

This sequence is illustrated in Figure 14:

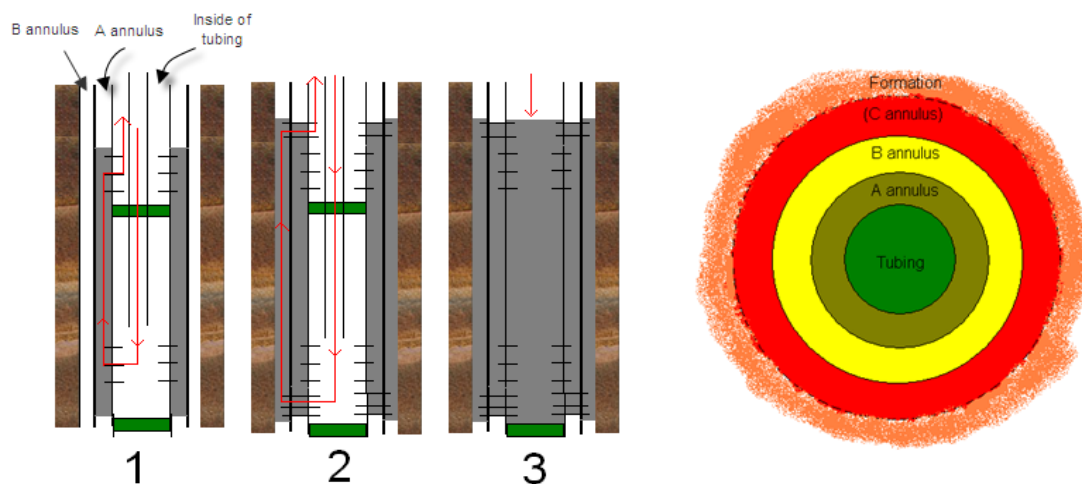


Figure 14: Suggested operational approach to obtaining proper cement in A, B & C annulus

Figure 14 is a conceptual sketch of how it might be possible to achieve cement in the A, B & C annulus. The greatest challenge related to this procedure is the verification of the cement plug. As far as this thesis has uncovered, there is currently no tool with the capability to log through multiple casings and cement. In these operations it is crucial to know what type of fluid that is present in the different annuli, and the condition of the cement and tubing. In other words; a new tool for logging through multiple casings needs to be developed, in order to perform the operation in this way on the NCS.

If this method were adopted and an approved way to verify the cement through the multiple casings were developed, theoretically a LWI vessel with CT (which has yet to be developed, as far as this thesis has uncovered) equipment could perform entire PP&A operations on wells where the downhole conditions is such that there is no need to perform heavy lifting activity.

This could have the potential for great time and money savings for the operator, in addition to more available time to perform drilling related activities. This need is in other words quite real, and whether it will be available in the near future is yet to be discovered. If an operation could be performed like this, it would require a new evaluation of the costs related to Statoil's FF PP&A cost estimation campaign.

2.2.3 Alternative to section milling

By using the HydraWash™ in combination with the Archimedes™ tool, some wells could be permanently plugged and abandoned without the need for section milling. Typical time for these operations are 4,7 days according to the service provider [12]. At the OLF P&A workshop forum in Sola, June 9 2011, it was revealed that both the HydraWash™ and Archimedes™ tools had been used in combination in two wells for CoPNO. Time results were very promising: 70 and 65 hours respectively for the two wells. The tool has been field tested by Conoco Phillips with promising results.

2.2.4 Solution to “the determination of TOC by the use of pressure monitoring” issue

In these incidents, alternative methods of verifying permanent barriers are required. When pumping the plugging material, one calculates the required displacement volume to get the plug to the desired depth. Then, this volume is circulated. After the circulation, the pumps are shut in. Cement curing is an exothermal reaction, and the heat generated will cause a pressure build up in the liquid on from the cement plug and up to the wellhead. This pressure build-up is carefully monitored, and when the pressure reaches a given cap, the pressure is bled off. One should try to let the pressure build up as much as possible, not to disturb the cement whilst it cures. When the pressure is bled off, the valves are shut. A new pressure build-up will now occur, but it will take more

time, and it might not reach the same peak as in the first build-up. Repeating this procedure, while carefully monitoring the differential and the volume displacements, until the cement is cured, enables determination of TOC.

2.2.5 Formation as barrier element

Formations that swell/creep can close around the outer casing, and thus making a tight outside seal. In order to qualify bonded shale formations as a barrier element, three criteria must be satisfied [13]:

1. Need to prove that the collapsed formation is shale (satisfies all the required barrier element properties listed in 2.1.4)
2. Need to prove that the formation has collapsed 360° around the casing, over a sufficient length interval (at least 50 m)
3. Need high enough fracture strength to avoid upwards fracture propagation

These three steps can be fulfilled by:

- Ensuring geological data indicates good shale presence
- Run ultrasonic & CBL logs
- Perform leak-off test to assess formation fracture pressure
 - o Ensure that this formation fracture pressure exceeds the maximum theoretical reservoir pressure with a gas column to barrier

Statoil has managed to get approval by PSA (Petroleum Safety Authorities) for their qualification of formation as barrier. However, as stated in APOS, bonded shale formations cannot be predicted. Therefore it shall be planned to use cement or other qualified plugging material on the outside of the casing. But once collapsed formation is proven in place and qualified, it can be used and is preferred used in PP&A. The effect of collapsed formation is shown in Figure 15.

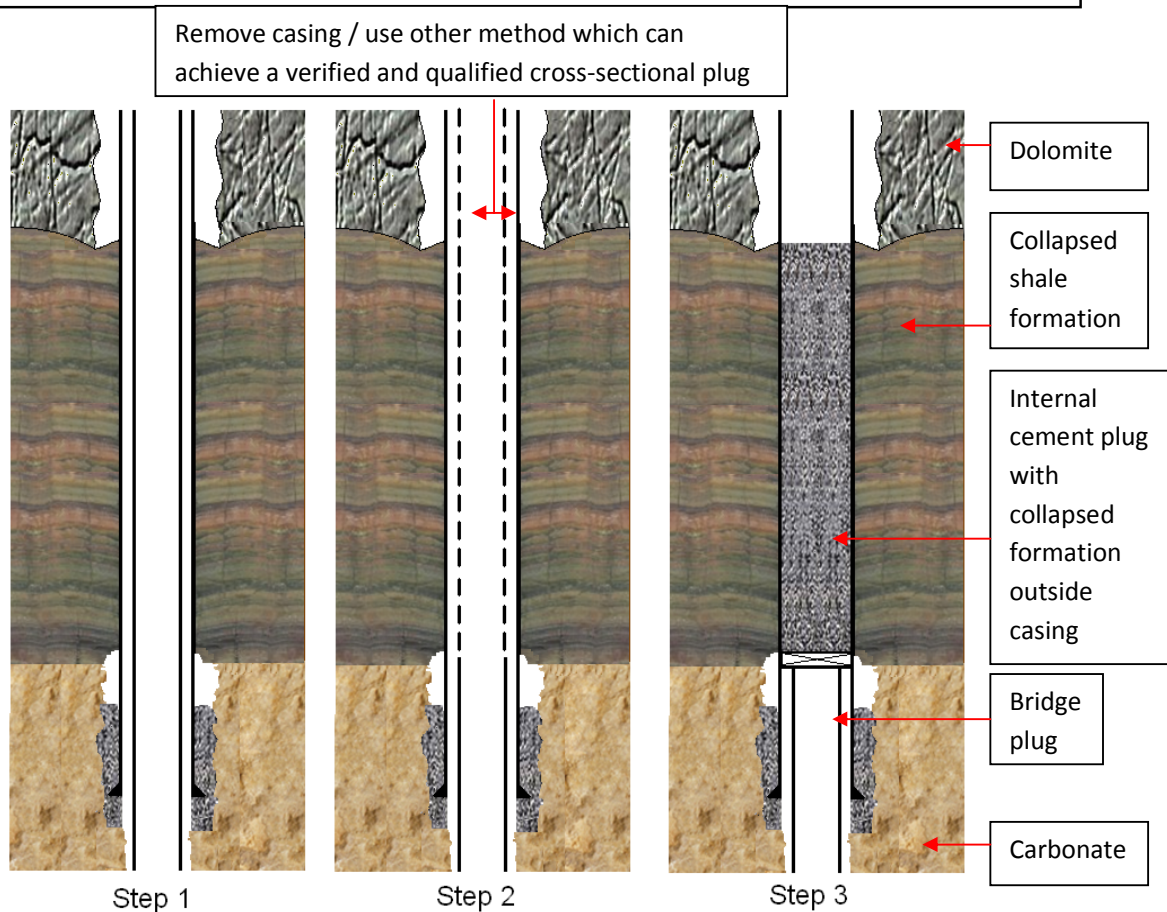


Figure 15: Collapsed formation as barrier element in PP&A.

Step 1 shows a well that is ready to be abandoned, using collapsed formation as a barrier element. As can be seen from the drawing, the collapsed shale formation is in contact with the outer casing (13 3/8"). It is assumed that all the requirements to the collapsed formation, listed in this subchapter, are fulfilled.

Step 2 is showing how the inner casing (9 5/8") is removed from the wellbore. This is to ensure access to the entire inner cross sectional area, such that a proper plug can be placed inside the casing.

By running USIT (Ultra Sonic Imaging Tool) and CBL (Casing Bond Log) logging tools, the bonding between formation and casing can be verified prior to plugging the inside of the casing. Once verified, and assuming the formation is qualified for this field, a foundation for the cement plug can be placed on the inside of the casing, e.g. a bridge plug. Subsequently a cement stinger may be run in hole to the depth of the plug, and cement may be pumped on top of plug, thus displacing the mud upwards. Together with the

internal plug (cement, or other suitable plugging material), the collapsed formation helps forming a barrier that fulfils the requirements in section 2.1.4.

- Good collapsed formation barriers have been observed as early as 2 weeks after setting casing.

2.3 Risks associated with PP&A operations

There exist a multitude of risks that impact the PP&A operations. The risks involved will impact the complexity of the operations and time needed to perform the operations, and thus they ultimately have an impact on the costs of well abandonment. For the sake of exemplification, a risk register from a real well, where PP&A has been performed, is presented in Table 20: Risk register covering the highest risk ratings in a real project. Appendix F. This register covers high-impact risks.

Each well is unique, and therefore a complete register of all the risks involved in PP&A operations would be too time consuming procure. However, it is true to say that the age of the well plays a major role in the risk register, as it impacts many of the uncertainty factors. The older the well is, the likelier it is that the downhole equipment to some degree is deteriorated. In extreme cases, much of the downhole casing or tubing may be deteriorated in such a degree that there is almost nothing left of it. When the casing or tubing is deteriorated, it may prove extremely difficult to pull it. The reason for this is that when it is attempted pulled; it breaks because it cannot support the underlying load. Implications of this are that when pulling casing or tubing, only a few meters at the time comes out of the well. This leads to many runs in and out of the hole, and much time is consumed.

The O&G UK guidelines to well abandonment cost estimation provide a comprehensive list of risk elements that impact the complexity of the PP&A operation. This list makes up the WAC (Well Abandonment Complexity), and this thesis provides a comparison between the WAC and Statoil's WCI (Well Complexity Index) in the following subchapter.

2.3.1 Comparison study between WAC and WCI

The motivation behind this study was to get an indication on whether or not the WCI that Statoil uses for well abandonment needs to be updated. Statoil reports their

performance in drilling and well related activities to Rushmore Reviews, which is a benchmarking database for operators. Statoil could approach the Rushmore Review reporting standard in order to simplify this benchmark reporting.

Legend: X= Not feasible, V= feasible, O= Optional	O&G UK guidelines				Covered by Statoil WCI?
	WAC				
Well Characteristics / Condition at abandonment	Type 1	Type 2	Type 3	Type 4	
Sustained Casing Pressure due to HC or overpressure	X	X	X	V	No
Not cemented casing or liner at barrier depths	X	X	X	V	No
Restricted access to tubing	X	X	V	O	No
Deep electrical or hydraulic lines present at barrier depths	X	X	V	O	No
ASV present	X	X	V	O	No
Packer set above cap rock	X	X	V	O	No
Site does not allow for CT/HWU pumping operations	X	X	V	O	No
Multiple reservoirs to be isolated	X	V	O	O	Yes
Tubing has leak (corrosion/erosion)	X	V	O	O	Yes
Inclination above 60o above packer (WL access)	X	V	O	O	Yes
Well with good integrity, no limitations	V	O	O	O	Yes

The table continues on the next page

Well Characteristics / Condition at abandonment	Type 1	Type 2	Type 3	Type 4	Covered by Statoil WCI?
Restricted access to casing	X	X	X	V	No
Not isolated fresh water aquifers / zones	X	X	X	V	No
Not isolated shallow gas	X	X	X	V	No
Poor primary casing cementation	X	X	V	O	No
No tubing in well	X	V	O	O	No
Poor integrity of conductor	X	X	X	V	No
Platform unable to suspend conductor load during raising	X	X	V	O	No
Water depth beyond limitation for cutting with LWI vessels (subsea well)	X	X	V	O	Yes
Conductor cutting/retrieval rigless	V	O	O	O	No

Table 2: Comparison between WAC and WCI

Table 2 provides a comprehensive list of certain risk factors that can be assessed for each unique well. Together all the risks listed here will yield an indication of the complexity of the PP&A operation. There is great confidence in saying that “the more complex the operation is, the likelier it is to be more time consuming and thus more expensive”. As can be seen from this comparison, only 25% of the items covered by the WAC is covered by the WCI. The WCI does, on the other hand, cover some items that are not covered by the WAC, but there is enough basis here to say that Statoil should consider an update of the WCI.

3 Regulations and requirements

3.1 Development of the requirements

In the interest of this thesis, the development of the requirements regarding P&A activities is not of much concern. The important thing is that how the requirements regarding P&A activities are today. The industry and the different host countries have become steadily more aware of the challenges surrounding the P&A activities. The real challenge regarding the P&A activities, with respect to HSE, is the prospect of eternity, seeing that all wells plugged and abandoned shall remain thusly with an eternal perspective. The work with this thesis has, for the author's point of view, revealed that no one can tell for sure whether the currently "best" methods of preventing flow from abandoned wells will hold with an eternal perspective. How cement and casing in the environment they are placed will or can deteriorate during tens and hundreds of years, is very hard to predict. But as this is the "best" method available it has to be adhered to.

This thesis presents the current requirements in the US, UK and Norway.

3.1.1 Concerning barriers

As per defined by NORSOK D-010, the primary barrier is "the first object that prevents flow from a source"[3]. A barrier consists of up to several well barrier elements. The secondary barrier is a back-up in case the primary barrier fails. §85 in the activity regulations enforced by the Norwegian PSA, indirectly state that there shall always be 2 independent barriers present during any drilling and well related activity [14].

3.2 NORSOK D-010:

"The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to replace oil company specifications and serve as references in the authorities' regulations"[3]. This standard is a set of guidelines which it is recommended to follow in order to ensure safe operations. As it is a set of guidelines, they are no direct legislation which companies have to follow. If however the company states that it will adopt these

guidelines as governing documents, they act as a “legislative framework”. In the interests of this thesis, it is chapter nine that covers the guidelines pertaining to well integrity during operations like plugging wells; both permanently and temporary. How to maintain well integrity during these operations will depend on the well conditions. Examples conditions that will influence the method of achieving well integrity could be the number of sources of inflow, open hole or cased hole, multibore with slotted liners or sand screens and multiple reservoirs with slotted liners.

According to section 9.3.8.2 in NORSOK D-010[3], “*All permanent well barriers shall extend across the full cross section of the well, include all annuli and seal both vertically and horizontally*”. To clarify the difference between the term “barrier” and the term “barrier element”, a barrier consists of one or more barrier elements. This is sometimes referred to as a “barrier envelope”, as it envelops all the elements needed to suffice as a barrier. When it is written “permanent cement plug barrier” in this thesis, it implies that the cement plug is either:

1. Laterally extended across the entire wellbore, thus making it a complete “barrier” or:
2. Consisting of a cement supported casing with cement on the inside.

Usually this standard states that there must at all times be a primary barrier envelope and a secondary barrier envelope whose function is to act as a barrier if the primary barrier fails. However, in the case of multiple sources of inflow, the usual requirement of one primary and one secondary barrier envelope is not sufficient. In those cases it would be necessary to have a barrier that isolates the potential sources of inflow from each other.

After the well is plugged entirely, it shall have:

- A primary barrier, whose purpose is to plug the reservoir
- A secondary barrier, which is the plug above the production packer (above the possible sources of inflow). It’s purpose is to act as a barrier in case of failure of the primary barrier

- An open hole to surface barrier which is a “fail-safe” well barrier. It shall be there in case of a potential source of inflow which can be exposed after e.g. a casing cut[3].
- And potentially plugs between each reservoir in a multi-reservoir well
- Both primary and secondary barrier shall be designed to be able to prevent flow of hydrocarbons to the surface

Figure 16 shows a typical barrier configuration on a well that has been permanently plugged and abandoned. There are several possible well configurations; NORSOK D-010 attempts to cover the required barrier envelopes in order to ensure a safe operation in the different cases, thus it should be consulted and adhered to. However, operators are free to use methods deemed technically equal or better than those presented in this standard. As of the plugging materials used, *“The materials used in well barriers for plugging of wells shall withstand the load/ environmental conditions it may be exposed to for the time the well will be abandoned. Tests should be performed to document long term integrity of plugging materials used”*. This basically means that each company are free to use whatever plugging material they want, as long as they can verify its integrity.

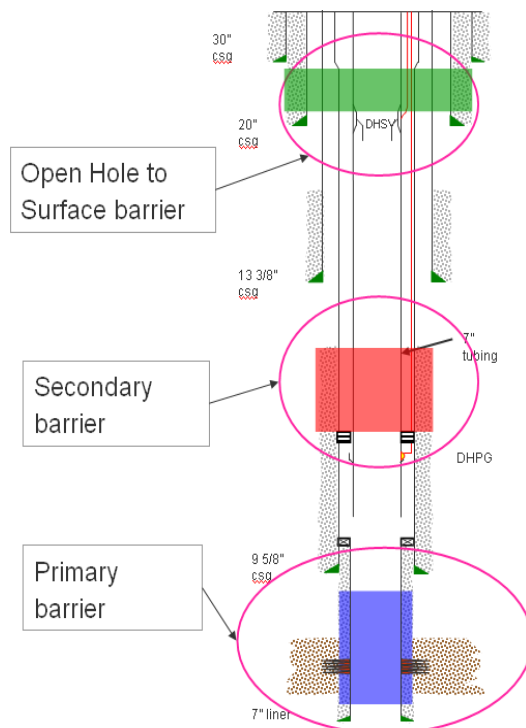


Figure 16: Typical well barriers in a PP&A cased and perforated, single reservoir well.

3.3 Decommissioning on the NCS and on the UKCS

A study of the OSPAR 98/3 requirements for decommissioning of structures [5] have been performed. These requirements are valid for the UKCS and the NCS. A comprehensive summary of them are given below:

- Everything shall in principle be removed, except any part of the installations that does not protrude from the seabed and concrete anchor base associated with a floating installation which does not, or is not likely to, result in interference with other legitimate uses of the sea.
- If the installations in question, excluding their topsides are
 - o *Steel structures weighing more than 10 000 tonnes in air*
 - o *Gravity based concrete installations*
 - o *Floating concrete installations*

The installations can be subject to an issue of permit to be left partly or wholly in place. This kind of application is subject to a majority of required documentation and investigation, which may be found in the OSPAR 98/3 Decision [5], but will not be discussed in more detail in this section. The scope of this work will vary, depending on the type of rig in question.

3.4 Requirements on UK sector

With regards to well abandonment, the requirements to barriers, barrier elements and plugging materials are a bit more elaborated than in NORSOK D-010. The last issue of these guidelines came in 2009 [15] while the last issue of NORSOK D-010 is of 2004. Therefore it is logical that the requirements are more elaborated in the UK Oil & Gas guidelines. All sets of guidelines are made to achieve the ultimate goal: Preventing migration of hydrocarbons underground, and to prevent migration of hydrocarbons to the surface; both of these with an eternal perspective. The UK Oil & Gas guidelines for well abandonment are made with reference to NORSOK D-010 (2004)[3], API RP 57 (American Petroleum Institute Recommended Practice - 1986) and the Mining Regulations of the Netherlands WJZ02063603 (2003)[16]. It is anticipated that the next issue of NORSOK D-010 will be updated to include a similar, more elaborate section concerning the PP&A requirements.

3.5 OCS GoM requirements for well abandonment

The descriptive regulations in the GoM for well abandonment states: “You must permanently plug wells according to the table in this section. The District Manager may require additional well plugs as necessary.” The table referred to in the quote is Table 3, and it is taken from 30 CFR (Code of Federal Regulations) §250.1715 [17].

PERMANENT WELL PLUGGING REQUIREMENTS	
If you have—	Then you must use—
(1) Zones in open hole	Cement plug(s) set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.
(2) Open hole below casing	(i) A cement plug, set by the displacement method, at least 100 feet above and below deepest casing shoe; (ii) A cement retainer with effective back-pressure control set 50 to 100 feet above the casing shoe, and a cement plug that extends at least 100 feet below the casing shoe and at least 50 feet above the retainer; or (iii) A bridge plug set 50 feet to 100 feet above the shoe with 50 feet of cement on top of the bridge plug, for expected or known lost circulation conditions.
(3) A perforated zone that is currently open and not previously squeezed or isolated.	(i) A method to squeeze cement to all perforations; (ii) A cement plug set by the displacement method, at least 100 feet above to 100 feet below the perforated interval, or down to a casing plug, whichever is less; or (iii) If the perforated zones are isolated from the hole below, you may use any of the plugs specified in paragraphs (a)(3)(iii)(A) through (E) of this section instead of those specified in paragraphs (a)(3)(i) and (a)(3)(ii) of this section. (A) A cement retainer with effective back-pressure control set 50 to 100 feet above the top of the perforated interval, and a cement plug that extends at least 100 feet below the bottom of the perforated interval with at least 50 feet of cement above the retainer; (B) A bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug; (C) A cement plug at least 200 feet in length, set by the displacement method, with the bottom of the plug no more than 100 feet above the perforated interval; (D) A through-tubing basket plug set no more than 100 feet above the perforated interval with at least 50 feet of cement on top of the basket plug; or (E) A tubing plug set no more than 100 feet above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 feet above the uppermost packer in the wellbore and at least 300 feet of cement in the casing annulus immediately above the packer.
(4) A casing stub where the stub end is within the casing.	(i) A cement plug set at least 100 feet above and below the stub end; (ii) A cement retainer or bridge plug set at least 50 to 100 feet above the stub end with at least 50 feet of cement on top of the retainer or bridge plug; or (iii) A cement plug at least 200 feet long with the bottom of the plug set no more than 100 feet above the stub end.
(5) A casing stub where the stub end is below the casing.	A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.
(6) An annular space that communicates with open hole and extends to the mud line.	A cement plug at least 200 feet long set in the annular space. For a well completed above the ocean surface, you must pressure test each casing annulus to verify isolation.
(7) A subsea well with unsealed annulus.	A cutter to sever the casing, and you must set a stub plug as specified in paragraphs (a)(4) and (a)(5) of this section.
(8) A well with casing	A cement surface plug at least 150 feet long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 feet below the mud line.
(9) Fluid left in the hole	A fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.
(10) Permafrost areas	(i) A fluid to be left in the hole that has a freezing point below the temperature of the permafrost, and a treatment to inhibit corrosion; and (ii) Cement plugs designed to set before freezing and have a low heat of hydration.

Table 3: Requirements well abandonment in the US. Taken from [17].

These requirements really do not leave much of a choice to the operators. Since well abandonment must be performed in this order, there is little room for innovation for the operators. Unless the legal rules and regulations are continuously updated, this may ultimately lead to poorer quality in well abandonment operations over time than if the regulations arranged for innovative solutions.

3.6 OCS GoM requirements concerning decommissioning

The rules for decommissioning in the GOM area are governed by the US Bureau of Ocean Energy Management [18], and are somewhat different from the OSPAR 98/3 decision [5]. They can be summarized as follows:

For wells [19]: All wells shall be permanently plugged one year after lease terminates. A downhole plug shall be placed in order to squeeze cement the entire perforated interval. A surface cement plug that has to be at least 200ft (ca. 65m) shall be placed. All cement plugs must be capable of preventing fluid migration to seafloor. Casings should be cut at least 15ft (ca. 5m) below seafloor.

For pipelines [20]: Pipelines can either be retrieved or buried on the seafloor. If the pipeline is to be buried on the seafloor, it needs to be cleaned according to regulations. Then it needs to be filled with seawater prior to the ends being buried 3 feet below the seafloor or covered with protective concrete mats, if required by the Regional Supervisor. All valves and other fittings that could interfere with other uses of the OCS (Outer Continental Shelf) should be removed. In either case, proper applications must be granted consent.

For platforms [19]: All platforms shall be removed within one year after the lease terminates. All platforms and other facilities (templates and pilings) must be removed to at least 15ft below seafloor. MMS (Ministry of Mineral Services) RSFO (Regional Supervisor office of Field Operations) may give consent to remove the platform or toppling of the platform at a designated position in order to convert it to an artificial reef.

3.7 Additional requirements imposed by the operators

In addition to governmental requirements, many operators have their own set of additional requirements. These may be stricter than the regulations.

3.7.1 Statoil ASA internal requirement (APOS)

APOS is the internal document which governs the way Statoil ASA operates. In relation to this subject, permanent plug and abandonment, this document is to a large extent

based on the NORSOK D-010 standard. However, there are situations where APOS requirements exceed the requirements in NORSOK D-010. One example of this is when it is possible to verify (by log) at least 200m of good cement on the outside of the casing. Then 1 correspondingly long plug may be used on the inside of the casing, from as close to the reservoir as possible and at least 200m into the previous (above lying) casing, and be qualified as 2 barriers. Another example is that APOS states: "The primary and secondary well barriers shall be positioned at a depth where the minimum formation stress at the base of the plug is in excess of the potential internal pressure". However, NORSOK D-010 [3] and some operators use the formation fracture pressure instead of minimum formation stress. The minimum formation stress is the same as the fracture closing pressure. Formation fracture pressure is usually gathered by performing a leak-off test. The measurements gained from this test are specific for that particular well and that particular location. The formation fracture pressure is always higher than the minimum formation stress, so this means that the APOS requirements are stricter than those of NORSOK D-010. There is an ongoing in-house study in Statoil concerning the impact of this stricter requirement. The reason for this study is to assess the consequences this criteria has on the performance. If deemed necessary, a change may be seen in the future, which may introduce the fracture propagation pressure as criteria.

PP&A	Formation
<i>Two barriers</i>	Permeable formation with overpressure or reservoir exposed (hydrocarbons present)
<i>One barrier</i>	Impermeable formation with overpressure
<i>One barrier</i>	Permeable formation with normal pressure (or less)

Table 4: APOS requirements to amount of PP&A barriers, depending on type of formation.

An overview of the description of the barrier functions in APOS can be illustrated as in Table 5:

Name	Function	Requirement to depth position
Primary Well Barrier	First well barrier against a potential source of inflow	Minimum formation stress at the base of the barrier shall be in excess of the potential pressure below.
Secondary Well Barrier	Back-up the primary well barrier, and applies where the potential source of inflow is also a reservoir	<i>As above</i>
Well Barriers between reservoirs	To permanently isolate reservoirs from each other. Can also act as a primary barrier for the reservoir below	<i>As above</i>
Open Hole to Surface Well Barrier	To permanently isolate an open hole from surface which is exposed after casing cut (this formation can be: <ul style="list-style-type: none"> i) Impermeable* ii) permeable with no HC and less/equal to normal pressure [seawater gradient]) 	As deep as possible in the surface casing and with the top minimum 50 m above the shallowest permeable zone

Table 5: Overview of how PP&A barrier functions and placement, according to APOS.

* For impermeable formations with overpressure, it shall be documented that no permeable zone is exposed (e.g thin sand lenses in shale etc).

If shallower permeable zones that may be a source of inflow exist, they shall be plugged according to the same principle.

3.7.2 CoPNO internal requirements on the NCS

In most cases, CoPNO follows the same requirements as Statoil. It is important to note that as long as the ultimate goal mentioned in section 3.4 is achieved and the operator is capable of verifying that the solution is in accordance to the requirements, the operators are free to choose their own solutions. This leads to different methods of achieving the same goal. Due to the focus of this thesis, an in-depth discussion of which method that is best suited to achieve this goal has not been performed.

3.8 *Impact of Rules and Regulations on the Time and Cost of PP&A Operations*

This section is to a large extent based on a presentation given by Tom Leeson from Halliburton at SPE's 3rd European Well Abandonment Seminar 29th March 2011 in Aberdeen.

After this thesis investigation of the regulatory regimes on the NCS, UKCS and the GoM, an interesting question arise: in what degree do the different regimes of rules and regulations affect the time and cost of PP&A operations in the various areas described. With that in mind, Halliburton launched a comparison project of recent well abandonment projects in GoM and SNS (Southern North Sea). The well abandonment projects in question were of relatively low complexity, and they were performed as rigless abandonments of platform wells. All the projects had similar well configurations and the same water depth and platform limitations. More than 12 wells in both the GoM and the SNS were investigated. The possible cost differential drivers were identified as:

- Legislation and regulatory standards
- Operational duration
- Well service costs
- Support costs

The operational procedure, which needs to be explained for the sake of argument, was a three-step through tubing approach. This implies that all the casings were supported by adequate cement, and that there were no wells with observed sustained casing

pressure. Also, there were no deep-set control lines present, and production packers were placed at a position where the minimum formation fracture pressure exceeded the maximum pressure potential from below. The three steps were as follows:

1. Plug the reservoir using a combination plug (mechanical plug with cement on top); adequate cement outside casing.
2. Main-bore cement plug (600ft high) to isolate normally pressurized water bearing zones. The A-annulus was reached using tubing punching. A viscous reactive pill (400ft high) was set as foundation for the cement plug in annulus in order to prevent cement slumping. The main-bore plug was set in the tubing and A-annulus with adequate cement towards the formation, thus covering the entire cross-section of the wellbore.
3. Conductors cut 3m below mud line using abrasive water cutting technology. Production tubing removed using a crane and tension cable.

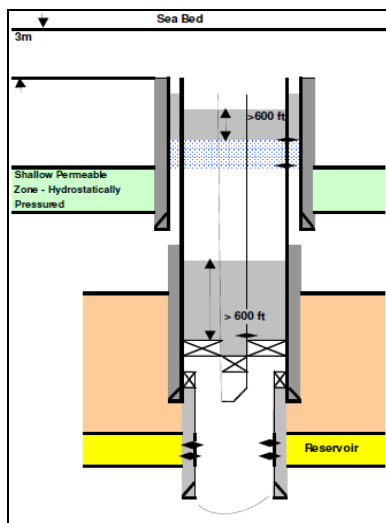


Figure 17: Well schematics pre-abandonment. Source: Halliburton presentation.

A schematic taken from the presentation is presented in Figure 17.

The average operational duration in the GoM and SNS well abandonments were marginally different. An average of 275 hours per well in the GoM and an average of 284 hours per well in the SNS were observed. The costs related to the well services had a harder impact on the total average cost. The scope of these supplies is:

- Well engineering
- Pumping and cementing services
- WL services
- Bridge plugs, tubing punches & cutters
- Tension cable
- Cement, fluids and viscous reactive pills
- Abrasive water-jet multiple casing cutting
- Multi-skilled crews and supervision

The actual figures of the average spread rates observed for the well services for the GoM and the SNS are of a sensitive nature, and therefore not presented in this thesis. However, a comparison between the two can be presented, and so they are displayed in Table 6:

Area	Spread rate
Gulf of Mexico	£ X/day
Southern Northern Sea	£ 1.83X/day

Table 6: Relative between spread rates related to well services in the GoM and the SNS.

This difference is probably a result of the GoM market being more mature and competitive, as the PP&A campaign started much earlier in this area than in the SNS.

The greatest impact on the costs related to the well abandonments was seen from the support service cost spread rates. These include:

- Self-propelled Jack-up barge with crane
- Helicopter and personnel transportation
- Supply vessels and materials transportation
- Client overhead

The support service cost spread rates which Halliburton uncovered from this research are also of a sensitive nature, and will not be displayed here. However, the relation between the two areas where as in Table 7:

Gulf of Mexico	£ X/day
Southern Northern Sea	£ 2.3X/day

Table 7: Relation between support cost spread rates for the GoM and the SNS.

It is important to note that the major contributor to this difference is the barge rates. They are ca. 4 times higher in the SNS area compared to the GoM area. The main drivers for these rates are:

- Design codes and specifications
- Environmental loading conditions
- Market availability

The conclusions Halliburton made after this comparison was that:

1. PP&A guidelines & regulations in the SNS do not add to the cost differential **for simple wells**.
2. GoM crews are only marginally more efficient than crews in SNS.
3. Well service rates are lower in the GoM, and contribute to ca. 30% of the cost differential between the GoM and the SNS.
4. Support service spread rates contribute to the majority of the cost differential.

4 Evaluation of time and cost estimation related to FF PP&A

A good cost estimate has to be adequate for the required phase of the project in question. This is important to keep in mind when performing cost estimation, and the phase most of Statoil's projects are in, is a very early planning phase to account for the assets needed for the PP&A campaign.

The following chapter is to a large extent based on Statoil's internal guidelines, APOS.

4.1 Approach to time estimation

In order for this thesis to avoid the "clutches" of confidentiality and because of the limiting extent of this thesis, the focus of this thesis is moved from cost estimation to time estimation. It is obvious that this approach is more palpable than an approach towards cost, seeing that the costs consist of a multitude of elements that vary from now and until the time of operation. This could be rig rates, service rates etc. The

motivation of the thesis is nonetheless to attempt a reduction to the overall costs. By evaluating the time required to perform an operation of a given type, it is ultimately easier to produce better cost estimation. The current cost estimation principles in Statoil will be briefly explained in the subsequent sections.

4.2 Current cost estimation methodology in Statoil

The current method used for cost estimation related to FF PP&A is a generic method, meaning its principles can be applied on any operation. This thesis will cover operations like well abandonment and decommissioning. The expected cost can be broken down in two parts. These are "Net Operating Cost" and "Contingency Cost". These two parts can further be reduced to five main elements. According to APOS, the main elements in cost estimation are:

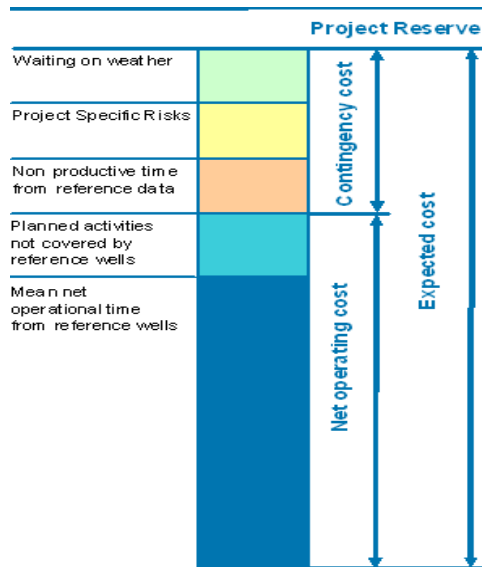


Figure 18: How expected cost can be broken down to smaller elements. Source: APOS.

4.2.1 Expected cost

Statistical simulations, taking into account risk assessment of the activity, shall be the basis of the expected cost estimate. The accuracy of the estimate shall be described by a low (P10) and high (P90) estimate. P10 means there is a 10% probability that the cost will fall exactly on that particular value or below, and P90 means that there is a 90% probability that the value will fall on exactly that particular value or below. This is sensible requirements, seeing that there is so much uncertainty related to the estimate. The higher the uncertainty, the more difficult it is to give a discrete estimate of the cost.

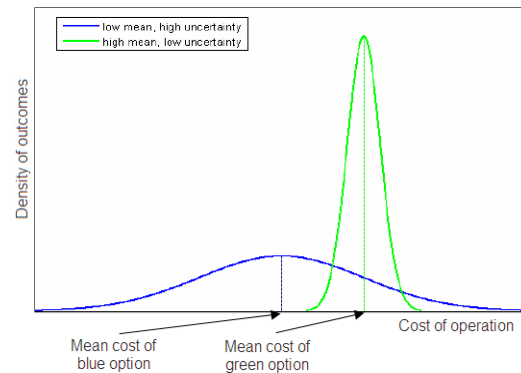


Figure 19: Two different cost outcome density distributions. Source: [21].

To represent the estimate as a probability distribution gives the decision maker a better basis for the decision needed to be taken.

Figure 19 shows how the cost outcome distributions may impact the decision to be taken. The green option has a high mean cost, but low standard deviation. The blue option has a low mean cost but with a high standard deviation. Cost of operation is on the x-axis and the density of outcomes is on the y-axis. With the mean cost as only criterion when choosing between the two alternatives, the blue option would be the best choice. However, if the decision maker is willing to take on a higher mean cost of the operation in order to reduce the uncertainty, the green option would be the best. This clearly shows how a distribution with

the density of cost outcomes could affect the decision to be taken.

4.2.2 Net operating cost

The net operating cost represents the execution of an operation that encounters no problems. For this post, the net operating time should be used as basis. The reason for this is that the rig rates and total day rates (rig rate + service rate) contribute most to the cost estimate.

4.2.2.1 Mean net operational time from references

Reference wells are wells where similar operations or part of operations have been performed. This renders them representative for the particular well. They form the basis of an estimate of the time required to perform an operation without any problems.

4.2.2.2 Planned activities not covered by reference wells

If the wells chosen as references do not include all the challenges that are actual for the well in question, adjustments need to be made. Examples of these adjustments could be other tools used for the operation

or slightly different well configuration than on the reference well(s).

4.2.3 Cost contingency

This part shall be included in order to ensure that items that are not quantified or identified (but likely to come in addition to net operating cost) shall be accounted for. Using a cost risk analysis, the expected and experienced risks shall be the basis of the cost contingency. It is obvious that the contingency cost shall reflect the costs associated with the estimated time contingency.

4.2.3.1 Non productive time from reference data

The contingency cost shall include an estimate of the non productive time. This is to be gathered from reference wells.

4.2.3.2 Project specific risk

Project specific risk is an important part of the expected cost estimation related to FF PP&A. The term “risk” is to many a word associated with negative impact. However risk has an upside and a downside. The ISO 31000 standard of 2009 defines risk as “the effect of uncertainty on objectives”[22]. This means that

project specific risk could imply an addition to the time or a reduction to it. This element is estimated using the principle that you multiply the probability of an event occurring with its consequence. It is important to note that, risks that have already been included in the reference data should not be added as project specific risk in addition, unless the risk is regarded as higher or lower than the reference data would indicate.

4.2.3.3 WOW (Waiting on Weather)

APOS presents a statistical overview of experienced WOW. This overview is divided in rig type / vessel and season.

	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%

Table 8: Statoils WOW statistics. Source: APOS.

These factors should be considered in the contingency cost.

4.2.4 Resource allocation

When performing resource allocation estimation to a project, a project reserve should be included.

Altogether, the expected cost estimation + project reserve should be in the range of a P70 estimate.

4.3 Time estimation related to FF PP&A

The investigation of time estimation is the chosen approach of this thesis due to reasons stated in section 4.1. According to APOS, when running statistical simulations in the time estimation process, lognormal distributions are assumed to give the best correlation to D&W (Drilling & Well) activities. As with all statistical simulations, the more reference wells available for input, the more realistic result. An illustration of a lognormal distribution is shown underneath:

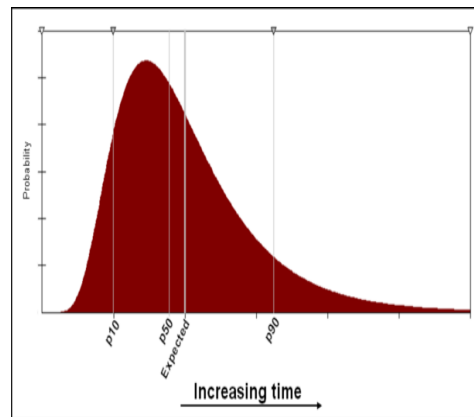


Figure 20: Lognormal distribution.

Given a unique case where no reference data are available, a triangular distribution should be used.

The cap for using lognormal distribution is that there are five or more available data points. If four or less points are available, a triangular distribution will be generated.

4.3.1 Reference data

The term reference data means all wells deemed relevant by the project, ranging from trouble-free wells to wells with substantial non-productive time (so called train-wrecks). Data which should be collected from the reference wells are according to APOS:

- “Geographical (wells in the same area and/or same installation)
- Geological (wells in similar geological environment)
- Technical (wells with similar technical designs / operations/category and challenges)
- Era (wells drilled in similar period of time)”

The reason for why reference data has played such a big part in the time estimation on PP&A operations which are yet to come is that it is the only data that the estimation team had readily available. The data that have been qualified as valid for FF PP&A estimation is mostly data taken from Phase 1 and Phase 2 (preparations for sidetrack). This basically means that the reference data used for estimation of FF PP&A lacks some aspects of PP&A operations. Without experience on conductor, surface casing and wellhead removal and decommissioning, the estimated results of Phase 3 are somewhat vague.

4.3.1.1 Quality of PP&A reported data in DDR

All the data from drilling and well activities performed by Statoil is supposed to be reported in the DDR system. But there are problems related to this data documentation. Sometimes, items that should have been posted under PP&A activities are posted at other posts. This could be posts like TP&A, intervention or in the worst case drilling. In other cases one might find items that should be posted under TP&A as PP&A items. This implies that when extracting reference data from DDR, there may be errors in the actual time spent on the operation.

One could argue that on a statistical level, there would be upsides and downsides related to the error in documentation. When taking a statistical estimation based on these data, a high amount of reference data would “eliminate” the effect of poor documentation. This would require further studies in order to be verified, and a brief check of 15 wells used as reference for PP&A operations on three different fields have been performed. The data used as background for Figure 21 and Figure 22 can be found in the Appendix D. The aim of this study was to get an idea of the status on the reported data in DDR.

As can be seen from Figure 21, 2/3 of the wells checked had error in the reporting. This lead to another interesting question: “What impact does this reporting error have on the time estimation?” The reports from the wells were checked briefly, just to get an indication of how this impacted the time estimation.

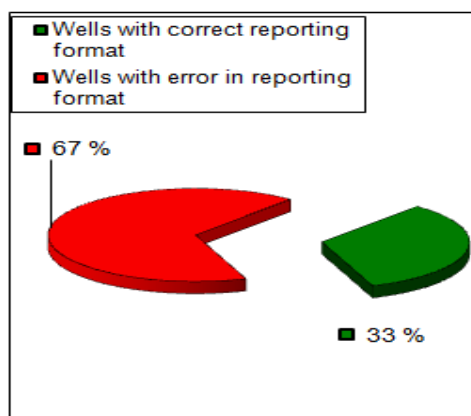


Figure 21: Status on DDR reporting quality of 15 random reference wells.

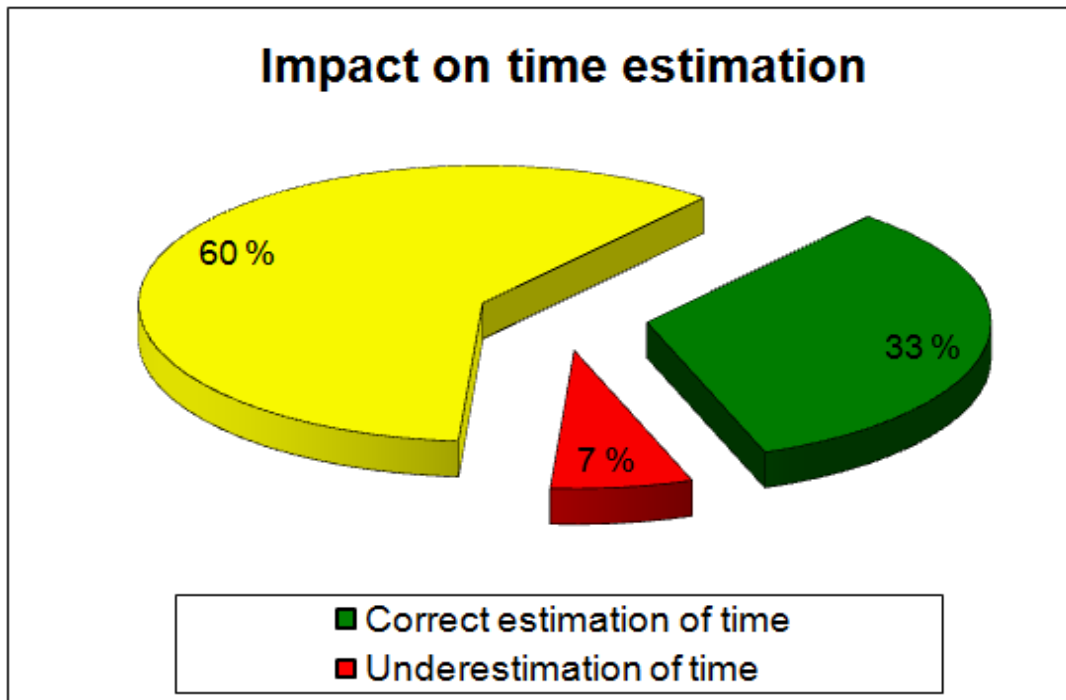


Figure 22: The impact of erroneous DDR reporting on time estimation.

As Figure 22 shows, it appears that the error in reporting leads to an overestimation of time. This reporting quality check would need to be performed on a larger number of wells, in order to assess the statistical impact and magnitude of the erroneous reports. The workload that would follow such a study would be enough to constitute a separate MSc thesis, and it is chosen not to do this in this thesis.

4.3.2 Technical limit time and target time

The operational unit shall know what the technical time limit related to the planned activities. This limit is the best possible time required for each individual operation based on actual experience. In the beginning of the era of FF PP&A campaigns, the experience is scarce. It is however the only thing that is possible to relate to, unless significant experience exchanges can be made with partners who have done this type of operation. The technical time limit should be calculated using

1. The 5 best reference wells
2. Reduction of contingency elements which are described in Figure 23

Figure 23 shows the timing elements related to drilling and well operations.

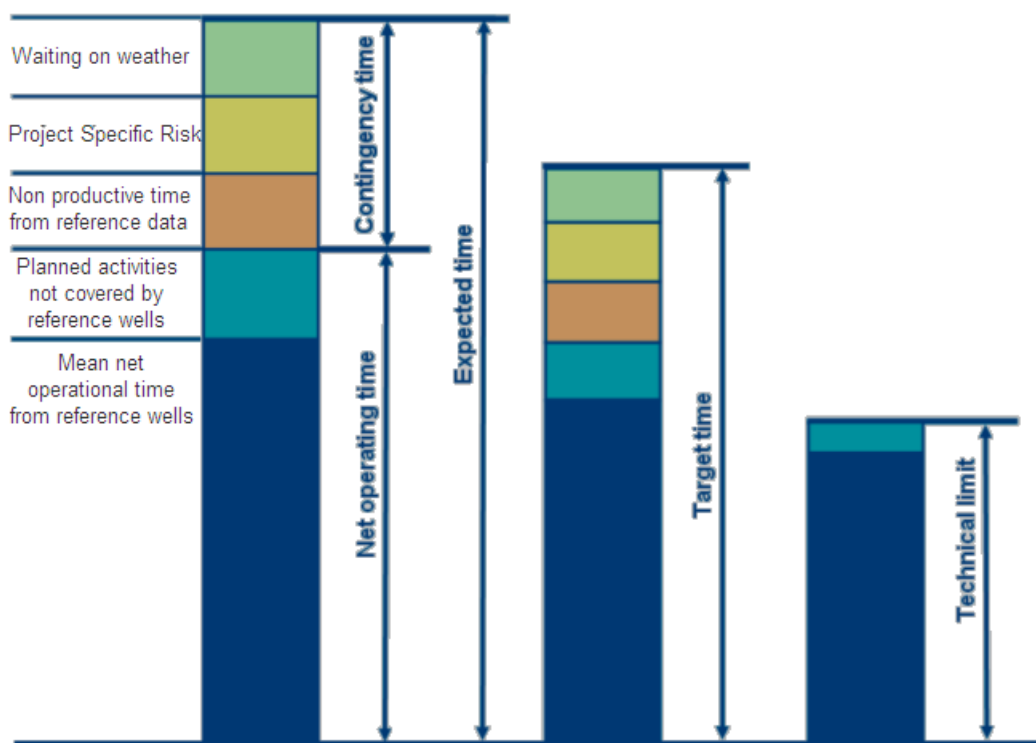


Figure 23: Elements included in Target Time limit and Technical Time limit. Source: APOS.

The five best reference wells will include the five best experienced operations of similar characteristics as the particular well in question. Reduction of contingency can imply that the WOW time, NPT (Non Productive Time) and project specific risk is removed.

4.3.3 Conoco Phillips versus Statoil

Through Statoil's partnership with Conoco Phillips, valuable information concerning both technology and time/cost estimation concerning P&A operations have been gathered.

4.3.4 Cost and time estimation as performed by CoPNO (Conoco Philips Norway)

When CoPNO performs cost estimation for different PP&A scenarios, they have all the possible well configuration scenarios already defined. Then a technician fits the current well schematic with one of the previously defined well configuration scenarios. Subsequently the technician enters in the detailed operation sequence in a predefined template. This template then shows what operations needs to be performed, how long time it is assumed to take and the cost associated with it. The costs are represented as a P10, P50 and P90. After this is done, the preliminary result is handed to a specialist who runs all the data through a probabilistic tool which yields output of possible cost scenarios, i.e. Monte Carlo simulations. The new P10, P50 and P90 for each operation are then presented. These are summed up to give a final cost estimate. All these numbers are presented with no non-productive time. However, if they are multiplied with a factor CoPNO assumes as general non-productive time and contingency time, the estimates match the actual cost of operations very well.

In the cost estimation campaign, CoPNO applies this concept on all their wells. Their experience is that once you have a smart framework set, it does not require too much time to perform the cost estimation, even with a detailed operational level planning.

4.3.5 Actual time data from CoPNO

Close to finalization of the master thesis, actual time data gathering at CoPNO were facilitated. Due to the limited time left, only five fields with a total of 61 wells were investigated. The ultimate data of interest in this study was the average time of PP&A operation per well. It must be specified that the average time found in this study may be slightly off the actual time. This is due to the format and filtering of the time data that were extracted from the databases. Of the 61 wells that were investigated, a couple of them had slightly incomplete datasets. It is reasonable to assume that even though a

couple of wells had incomplete datasets, the impact on the total result is small, seeing that they constitute less than 5% of the total data set.

Since Statoil has little available data on Phase 3 of operations (from placing of tophole PP&A plug to removing the wellhead), this information was considered as valuable experience. An attempt to extract time data from the initiation of Phase 3 failed, as the coded language in the operational level in the DDR system was different between the two companies and therefore hard to compare directly. However, it was possible to extract time data from approximately the time of cutting of the tophole casing. This is still valuable information for Statoil, but it must not be mistaken for complete actual Phase 3 time data; it is only from a certain stage in Phase 3. Due to the sensitivity of the data, the fields and wells under investigation has been made anonymous.

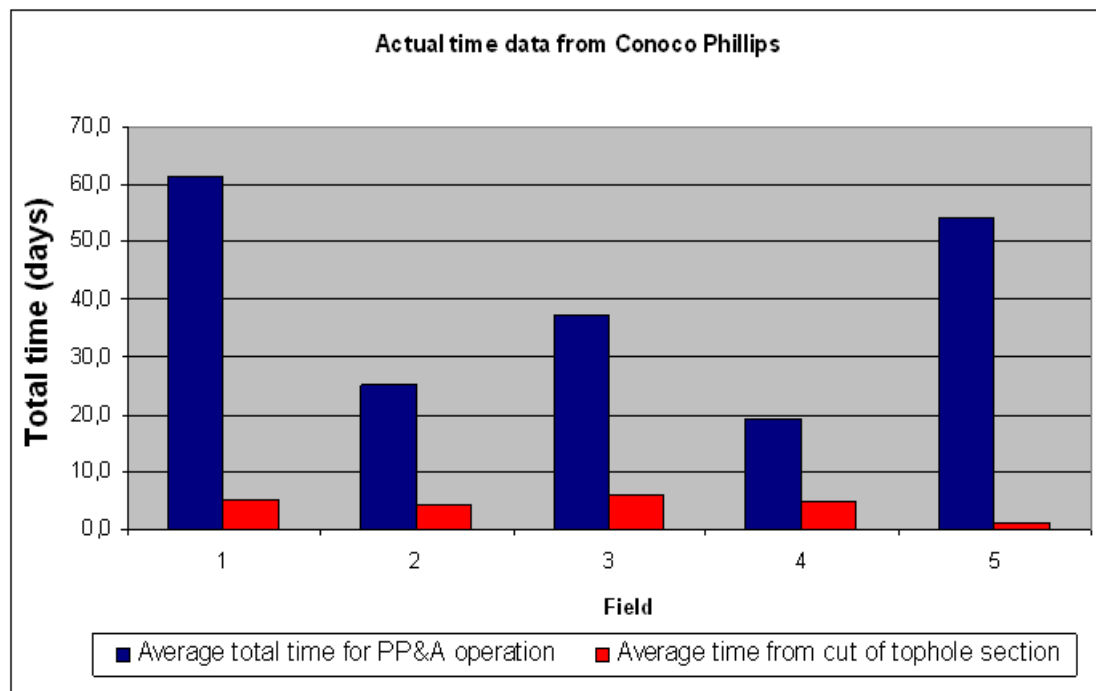


Table 9: Actual time data from Conoco Phillips

As can be seen from this Table 9, the last stage of the PP&A operation usually consumes a small portion of the PP&A operational time. In this instance, many of the wells were complicated with several possible zones of inflow / cross-flow. This implied that several plugs had to be set in the main bore of the well, and this requires a substantial amount of time.

Total average time per well for all the five fields were 39,3 days and the average time from cut of tophole section and wellhead was 4,3 days. On one of the most recent fields, the average time from cut of tophole section to the end of operation is 1,2 days, due to operational learning.

4.4 Cost estimation as per Rushmore Reviews / O&G UK guidelines

This chapter is to a large extent based on the presentation “Well Decommissioning Cost Estimation” given by Steve Kirby (SASOK LTD) at SPE’s 3rd European Well Abandonment Seminar 29th March 2011 in Aberdeen, where he represented the O&G UK Workgroup 5.

Rushmore Reviews is a database which the different operators can use to benchmark their drilling and well related operational performance with the other operators. According to the official website: *“In 1988 a group of Operators comprising Amerada Hess, Amoco, ARCO, BP, Chevron, Conoco, Marathon, Mobil, Occidental, Shell, Sun Oil and Texaco decided to improve the way in which they shared offset well data and drilling performance data.”*[23] Statoil joined this database later on. 1994 was the year when they introduced the CPR (Completions Performance Review) and in early 2009, the formal APR (Abandonment Performance Review) was launched. This enabled the operators to share and benchmark their well abandonment data with each other. In order to get a common template that is capable of serving as the basis for the data reporting in APR, O&GUK (Oil & Gas UK) Workgroup 5 has developed a guideline to estimating liability and well abandonment cost process. These guidelines are best suited for field-wide well abandonment assessments, and not single well abandonments. The Rushmore Database mirrors the O&G UK guidelines on cost estimation. For well abandonment, the costs are dependent on many factors. These may be summarized to

- Location of the well: Platform, subsea (or land)
- Complexity of well abandonment
- Phases of abandonment
- Duration of operations
- Total day rates (rig rates + service costs, the total cost of operations per day)

Table 10 gives an indication of how the well abandonment complexity could be defined:

Abandonment complexity				
Type 0	Type 1	Type 2	Type 3	Type 4
No work required (only cut and pull wellhead)	Simple rig-less work required	Complex rig-less work required	Simple rig-based work required	Complex rig-based work required

Table 10: Ideas how to define abandonment complexity. As proposed by O&GUK

O&GUK proposal to the division of well abandonment phases are almost identical to those explained earlier in the thesis. Table 11 illustrates this:

Well abandonment phases and brief description		
Phase #	1	Reservoir abandonment
	2	Intermediate abandonment
	3	Wellhead Conductor removal

Table 11: Oil & Gas UK definition of well abandonment phases

The guidelines propose how to develop the level of detail in the planning process, as COP (Cessation of Production) approaches. Table 11 is a representation of how the O&GUK guidelines propose how to steadily increase the level of details in the planning phase of a field well abandonment campaign as COP approaches.

These two tables are possible to add together, thus giving a framework for classifying a well according to the guidelines. This is done in Table 12, exemplified by a platform well.

(Well ID) Platform well NO 99/99-A99			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			X		
	2	Intermediate abandonment			X		
	3	Wellhead conductor removal		X			

Table 12: Individual Well P&A code classification.

This particular well would have the P&A code PL (2,2,1). If it is a subsea well, it would get the suffix “SS” and if it is a land well, suffix “LA” should be applied. A subsea well where all phases is extremely difficult, and requires rig would get a P&A code SS (4,4,4).

To apply this method on an entire field, one could insert the amount of wells which comply with the different codes in a matrix like Table 12. Afterwards, the duration of each P&A coded well could be filled in the matrix.

Next, the spread rates for the required equipment must be determined. This can be done through internal and external benchmarking or deterministic modelling. At this stage it is important to state all the assumptions that are made for the given spread rate estimates. When multiplying the different durations with the respective spread rates, a cost estimate is obtained for each well. Multiplying this cost estimate with the number of wells in the field will yield a cost estimate for all the wells in the field. After adding once-off costs, like mobilisation/demobilisation of rig, site preparation, location survey and decommissioning of platform, related to the field abandonment campaign, the ARO

(Asset Retirement Obligation) can be obtained. This is an obligation which provides for future disposal of assets, i.e. the well abandonment campaign and decommissioning in question. Figure 24 shows how to apply the O&GUK guidelines for cost estimation on a field-wide well abandonment campaign.

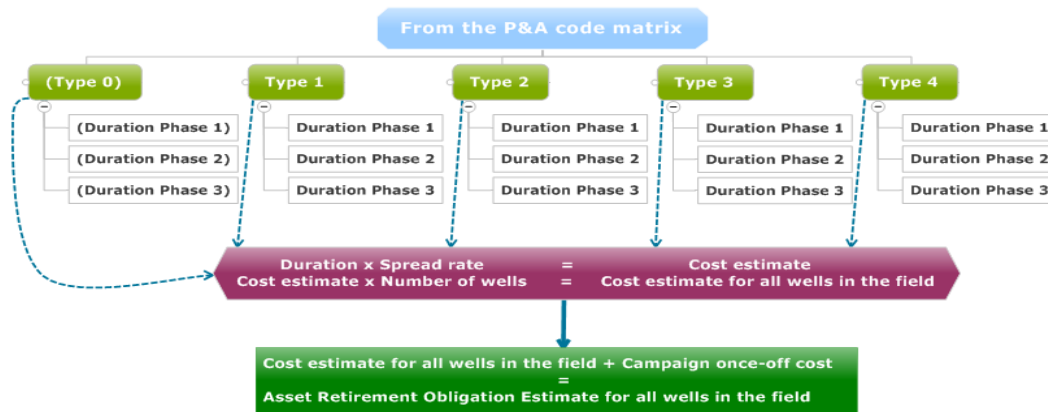


Figure 24: Flowchart for application of O&GUK cost estimation.

In order to illustrate this, a calculation example with tables is given. In this example, a field with a mother platform with wells and satellite wells are presented. NB! Numbers are imaginary. First input is the amount of wells that fit each P&A code:

Platform			Abandonment complexity				
			Type 0	Type 1	Type 2	Type 3	Type 4
All wells			No work required	Simple Rig-less	Complex Rig-less	Simple rig-based	Complex rig-based
Phase #	1	Reservoir abandonment	0	5	5	4	6
	2	Intermediate abandonment	0	1	6	9	4
	3	Wellhead conductor removal	0	12	7	1	0

Table 13: Determining amount of wells which fit each category.

Next input is the duration each phase will take per well, depending on P&A code:

Platform wells duration of phases (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	4	6	4	12
	2	Intermediate abandonment	0	5	7	6	14
	3	Wellhead conductor removal	0	2	3	1	4

Table 14: The duration of each phase, depending on P&A code.

Next input is estimated spread rates for the different-setups:

Estimated spread rates for different setups (nominal currency per day)	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
Platform / fixed rig	0	45 000	60 000	70 000	70 000

Table 15: Input of spread rates for the different set-ups.

The final step is to multiply the durations with the respective spread rate and then the number of wells:

Platform well abandonment estimate			Abandonment cost estimate				
			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	900000	1800000	1120000	5040000
	2	Intermediate abandonment	0	225000	2520000	3780000	3920000
	3	Wellhead conductor removal	0	1080000	1260000	70000	0

Table 16: Costs for all wells in each category. The sum of the cells will equal to the estimated field-wide well abandonment cost.

Estimated well abandonment cost = 21,715,000, which is the sum of all the cells in this matrix. As mentioned above this cost estimate only include the operations themselves along with spread rates for the required equipment. To get an overall understanding of the total cost, it would be necessary to include once-off costs, e.g. decommissioning, engineering and site preparation etc.

4.4.1 Level of accuracy in planning phase of PP&A campaigns

Table 17 shows how the level of accuracy in the planning phase should develop as COP approaches.


	Time to COP	Proportion of wells required for review	Approach required to review the selected wells
 Increasing level of accuracy in the planning phase needed	More than 10 years	10-25%	<i>Field-wide review of the representative wells</i>
	5 to 10 years	25-50%	<i>Well-by-well review of sample to define concept design and associated work scope</i>
	Less than 5 years	<u>All</u>	<i>Detailed, full, well-by-well review. Timing of abandonment phases may need to be considered.</i>
	Imminent	<u>All</u>	<i>Detailed well-by-well review of status, integrity, work units required and service costs</i>

Table 17: Level of accuracy in well abandonment campaign planning as COP approaches.

The scope of the O&GUK guidelines [24] that is planned to be published in Q2 2011, from where Table 17 is taken, does not cover AFE (Approval For Expenditure) estimates. Approval for expenditure is the permission given from licence owner to spend and set aside capital for project execution.

5 Discussion

This section will discuss some of the issues mentioned earlier in the thesis in a more thorough manner.

5.1 Reference data as basis for time and cost estimation

As mentioned in chapter 3, the current method of performing cost estimation in Statoil is generic and based on reference data. This method is based on using reference data as input for simulations that produce a probability distribution for different cost scenarios. Since the method is generic, it is applicable to all types of operations. This basically implies that in a relatively short time, compared to a highly detailed analysis, it is possible to get an estimate of costs related to a certain operation. However, if the input data (reference data) is scarce and of low quality, i.e. little experience with the operation in question, the output of the simulation will be of poor quality. Since Statoil has very limited experience with Phase 3 of PP&A operations, this could jeopardize the quality of the FF PP&A estimates. Another issue is that if a highly detailed level analysis were to be performed, this would require an extensive amount of work. This work should preferably be done with a dedicated team with experienced personnel. One must ask whether this would be beneficial: is the precision of the estimates of such high importance that it must be refined to the best possible extent?

The resources needed set aside for performing all the FF PP&A operations required by regulations are vast in size. If a detailed work and cost analysis has the potential of reducing the estimates by several billion NOKs, it should be worthwhile to consider. Technology has developed during the last decade since Statoil performed the last Phase 3 of PP&A operations. One example of this is the technology available for cutting and removal of surface casing, conductor and wellhead[2]. Although APOS states that data which is not covered by reference wells should be adjusted for, there exists a multitude of available solutions and technologies which could be used and whether the people performing the actual estimates are aware of these or not is uncertain. Some of the new solutions have not been implemented in the reference data and this could potentially render the results of cost estimations questionable. A dedicated FF PP&A team would

spot these new technologies and take them into account. This is one example of how a dedicated team could have the potential to reduce the estimates.

5.2 Regulatory regimes

The following subsections will discuss some of the issues concerning regulatory regimes.

5.2.1 Descriptive versus functional regulatory regimes

The regulations and guidelines concerning well abandonment on the NCS (NORSOK D-010) are of a less descriptive characteristic than its counterparts in the GoM and UKCS. NORSOK D-010's more functional characteristics encourage operators to find the best possible technology which ensures facilitation of the ultimate goal of proper permanent plug and abandonment operations.

The consequence of a more descriptive set of regulations, as in the GoM area, will eventually create a tendency for the operators to perform as closely to the limits of acceptance as possible. The result is that operators fulfil the requirements by a small margin, while saving as much money as possible. This sort of regime does not encourage the generation of new technology which may ultimately ensure safer and better well abandonment results.

5.2.2 Impact on learning curve effect caused by regulatory regimes

Post-disaster regulations that can be seen after the Macondo incident in the GoM may have detrimental impact on the learning curve effect in PP&A operations. According to the "Notice to Lessees" and the regulations in the US [25], "You must permanently plug all wells on a lease within 1 year after the lease terminates". This implies that it will be harder for operators in this area to accumulate wells that are ready for abandonment, and thus benefit from the learning curve effect. This has direct economic consequences, but it may also have operational quality consequences. The learning curve effect implies that the cost of abandonment of wells decrease until a certain level is reached, but another effect is that the quality of the operation is improved. However, the sooner a well is abandoned, the less time and chance there is for the downhole equipment to deteriorate. There are numerous examples of wells that have been suspended for many years, pending a field-wide well abandonment campaign. If some wells are suspended

10, 20 or 30 years before permanently plugged and abandoned, there is no knowing of what may be encountered when entering the wells to perform PP&A operations. This is probably part of the motive behind this legislation in the US.

5.3 Delay in provision of services

The increase in demand of PP&A operations will have the potential of driving the prices up, due to lack of supply capacity. Due to varying rates and availability, the cost-wise optimal timing for PP&A operations may be hard to predict. In this regard it is important to consider the fact that delaying PP&A operations, in order to hit a better timing cost-wise, will result in further and perhaps excessive deterioration of downhole equipment.

5.4 Reluctance to apply new technology

As the PP&A wave hits the industry harder, a multitude of new technological approaches will be suggested by the service providers. It is of great importance to monitor these new ideas, and assess their potential. As one should be advised not to automatically heed and follow all the suggestions, the wait-and-see tactic may increase the delay of new products entering the market. New technology is dependent on tests and field proving, and if all the operators have the attitude: “We wait and see if some of the other operators get any success with this product”, the timing gap between actual need and access to supplies will increase greatly, and some of the good ideas may fall through. This phenomenon is governed by the financial situation and attitude of the investor, and the operator’s willingness to apply new technology.

There is always a risk related to the application of new technology, and thus it is natural that operators in some degree are reluctant to apply new solutions. If a service provider comes with a unique product, it implies that that particular service provider has monopoly on that product. If there are no decent contingency solutions, given that the product fails, the operator will have major technical problems and cost issues when preparing remedial actions.

But altogether, it is important that the operators and the service providers meet somewhere around the middle, and find and apply sustainable solutions for both parts and the rest of the world.

5.5 Understanding of downhole conditions

It is of vital importance to understand the current downhole conditions during preparation and execution of PP&A operations. Operators should heed the advice of performing proper investigations and logging operations of the downhole environment rather than only looking at the original designs of the wells before commencing PP&A operations. There are numerous incidents world-wide where the downhole conditions are severely altered, compared to the original designs, and this fact can potentially have a great impact on the planning, preparation and execution of PP&A operations.

5.6 Cut and leave tubing in hole

Usually cement is used as plugging material. If the tubing is cut and left in hole may create narrow clearances which subsequently may lead to bridging or bad placement of the cement. Also, the borehole is usually inclined. The consequence of this is that after cut, the tubing will usually be positioned on the low-side of the wellbore. Therefore it will be very difficult to place cement in the low-side of the wellbore, under the tubing. Both of these events have the potential to yield a poor cement job result. Alternative plugging materials with different rheology could have the potential of eliminating the issues with small clearances and placement below the tubing on the low-side of the wellbore. One could easily imagine how water would fill around the tubing. ThermaSet® can be designed in such a manner that it resembles water when being pumped.

5.7 Possible vessel configurations

The following subsections will present some proposals to how it could be possible to combine different PP&A vessels.

5.7.1 LWI (Lightweight Intervention)

LWI vessels (e.g. Island Wellserver and Island Frontier) have equipment to bullhead and kill the well. First the well is bull-headed, then the tubing is punched and finally circulation is established through the flow line. They also have wire line equipment to install permanent mechanical plugs and cut and pull wellhead and XMT. Due to the limiting extent of this thesis, there has currently not been uncovered any LWI vessels that have the capacity to cut and pull tubing and completion or place cement on top of

mechanical plugs. There are however ongoing projects concerning the use of CT (Coiled Tubing) on LWI vessels. If that could be done, there could in addition be a possibility to set cement plugs with the LWI vessels. This could have the potential of saving time and cost compared to the use of heavier equipment. This solution would need to adjust for the extra fatigue problems which could occur if the CT were to hang loosely in the sea.

5.7.2 LWI & Cat B (CT)

In some cases, much of the P&A operation could be performed by a combination of LWI and category B vessels. The category B vessels have CT on board, rendering them able to perform heavy intervention where CT is necessary to install cement barrier plugs. In those cases the LWI vessel could typically perform diagnostic wire line run with the aim of uncovering the downhole conditions, and install the foundation (mechanical plugs) for cement barrier plugs. Then the category B vessel could perform the setting of cement barrier plugs and cut and pull wellhead and XMT.

LWI vessels have a less expensive spread rate/day rate. It is also natural to believe that when the CAT B rigs come, they will also be cheaper than a full scale rig. When this combination is made available, it would have the potential to liberate more rig time. This could lead to an increase in drilling related activities, thus increasing productivity. On the downside, the vessels mentioned here, are not as robust as a rig. In case of unplanned events occur during the PP&A operation, these vessels would have less flexibility in means to handle the situation. If a situation occurred, which were too complex to solve with the LWI vessel or CAT B rig, the need to mobilise an additional full-scale rig would arise. This would in turn lead to an escalation of costs, and the operation would be considered a major failure.

5.7.3 LWI & rig/derrick

In other cases, where heavier workover operations are required, the LWI can work in combination with a rig/derrick. Examples of operations which require this type of intervention are cutting and pulling of tubing and completions. In operations like this, the LWI vessel could kill the well and install the required foundations for cement barrier plugs. Afterwards the rig can pull the tubing and cut and pull the casings. If there is a

need for section milling, or other viable alternatives to section milling, (such as not being able to verify good cement around casing) the rig could perform this too. Finally the rig can cut and pull the wellhead and XMT.

5.7.4 Rig

A rig can perform all the operations mentioned in this section. If the marked is pressed for LWI vessels, maybe a rig is the only possible alternative.

5.7.5 Other possibilities

The use of LWI vessels in combination with jack-up lift vessels have been used in the GOM. In these cases the LWI vessels perform most of the work from killing the well to plugging the well. The jack-up lift vessel has a much greater lift capacity than the LWI vessels, and can therefore perform heavy lift operations if required. There is little availability of this option in the North Sea. Maturity of the market is one of the important factors in this example.

Rigless abandonment is an option in the cases where a production platform without rig/derrick is on site. In these instances, equipment which enables rigless abandonment can be rigged on the platform. This equipment includes amongst others different jacking equipment. A company called Subsea P&A, which is a joint venture between the NCA-group and Island Offshore, is developing tools that enable LWI vessels to do as much of the subsea PP&A operations as possible. One of the most critical success factors in this work is to unlock the possibility to pull tubing rig-less. They are working on a solution for this, and so is another company, called Geoprober Drilling. The product Geoprober Drilling is performing feasibility studies on, they call "Sub Sea Tubing Unit", and the reader is advised to consult their webpage for further information [26].

If the rig PP&A efficiency can be matched with these rig-less concepts, there exists a saving potential of up to 70%. Assuming 30 days per well, and ca. 1000 subsea wells on the NCS, we are talking about a saving potential of ca. 160 billion NOK. This is a huge potential and we may see some of it pay-off if the proper initiatives are taken by the operators on the shelf.

5.8 Planning and preparation approach

After investigating PP&A projects performed by Statoil ASA, namely Yme Beta, Yme Gamma and Tommeliten, there are several aspects of the organization which is deemed favourable. The planning model of the final PP&A operation at Yme Beta was very detailed. The leading participants in this project made a higher level structure of what needed to be done. Subsequently all the involved personnel were gathered for detailed workshops. These workshop days delegated a clear responsibility distribution. Specialists from Statoil ASA, rig owner and service companies were assigned groups depending on field of expertise and area of work, who in the first instance were asked: How fast can we plug these wells with all the safety requirements that follows such an operation? The result of the discussions during the first day was that each well could be plugged and abandoned in 12 days. The topic of the next workshop was: What solutions are available in order to execute the operations in 12 days per well?

Each workgroup were engaged, and they developed solutions, plans, contingency plans, decision trees etc. The work in the groups were coordinated by a central planner and coordinator, approved and then sent to rig. The level of detailed planning in the process was very high; down to the level of what was to be done every hour of the operation.

The division in work groups, and the clear feeling of responsibility which followed this, is deemed as a crucial success factor. The people involved in the planning were to partake in the operation from land or rig. This led to a complete understanding of the challenge in the value chain, rendering the people involved capable of finding solutions when problems occurred.

One of the reasons why the P&A operations have increased in duration may be due to the fact that the level of details in the planning process, and the ability to transfer the personal feeling of responsibility and personal understanding of the entire operation, have been reduced. This has to do with amongst others the available workforce. Planning in such a detailed level and ensuring involvement from all the partaking persons requires a lot of workforce and time. There are however motivations for performing operations in such a detailed level:

1. It is economically sustainable to have many hours of pre-operation planning, if it leads to less down-time/more efficient execution of the operation.
2. Detailed planning and involvement of all relevant personnel may increase the safety of the operation.

Point 1 is difficult to measure directly. In order to assess the extent of this effect, one would need to do a long-term test with 2 groups of equal competence; each operating on a different level of detail over several similar operations. But from the reports of Yme Beta, which had a very detailed planning level, the experiences from this are very good.

However one may argue whether there is a real need for the very detailed planning nowadays (2011) that integrated operations and real time operations are so readily available. In an environment like this, it is possible for the land based crew to assist the crew at rig on a minute to minute (even second to second) basis. This way of operating renders the operational unit able to take well-informed decisions rapidly.

Another reason why the operation went so smoothly may have to do with the fact that the wells that were abandoned were young of age. They were drilled in the period 1996-1999. Thus the downhole equipment was less deteriorated than for much older wells, i.e wells drilled in the 1970's and 1980's. There are therefore reasons to suspect that very old wells will be more troublesome to abandon, than in the case of Yme Beta.

5.9 Learning effect on field-wide PP&A campaigns

M.J Kaiser and R.D Dodson investigated the trends of P&A costs in the GoM from 2002-2007 [27]. What they discovered where that as the number of wells increase in a well abandonment campaign, the unit cost typically decline. The observed day rate contracts do not follow a clear trend. But for turnkey contracts, the costs follow a more well-defined trend. As the number of wells increases, the average cost per well decrease considerably.

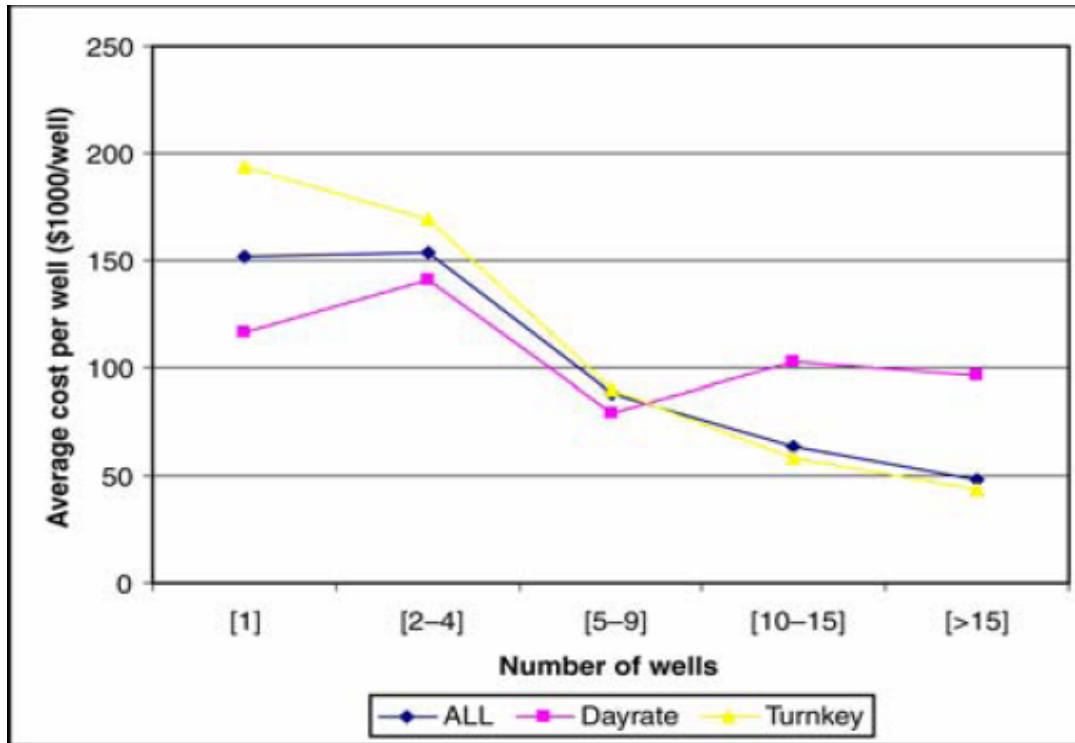


Figure 25: The impact of scale on average cost to P&A by contract type. Source: [27].

The background data for this graph is shown in Table 19 in the Appendix E. This data may not represent the whole industry, as it is data from a single service provider. However, the authors of the report [27] believe that the benefits of using a consistent and homogeneous dataset outweigh the drawbacks from possible contractor bias. All the wells were performed on dry trees with a water depth of less than 400ft. Since deepwater and subsea wells are generally more complicated to perform P&A operations on, one may say that the results from this study are not valid for deep water campaigns. Even though it would be necessary with a deep water/subsea case study in order to assess the potential learning effect on large scale well abandonment campaigns, it is not unlikely to think that there are cost-wise beneficial learning effects on large scale well abandonment performance.

5.10 Actual time data

Actual time spent on PP&A operations from CoPNO data is 39,3 hours. Data shown from the Brent abandonment campaign by Shell on SPE's 3rd European Well Abandonment Seminar indicated that average time on the wells were between 35-40 days. At the OLF P&A workshop forum in Sola June 9 2011, Baker Hughes presented some time data for 10-12 wells that they had abandoned using their newest section milling technology. The typical time ranges for total PP&A of the wells were from 35-65 days. 10-15 years ago the average time was much less. There can be many reasons for the increase in average time per well abandonment. Here are some ideas presented:

- More complicated wells to abandon
- Stricter requirements: 2 independent barriers at any given time of drilling and well operations, at least in Norway
- Higher age: higher degree of deterioration of downhole equipment

There are many opinions on this subject, but the three points presented here, are just to indicate some of them.

To underline the point about less average well abandonment time 10-15 years ago, an example from Statoil is presented in Table 18. With an average actual time of 10,6 days, Yme Beta is an example of a four-well campaign that went really well. Nowadays, the average number per well abandonment in Statoil is reckoned to be between 25-45 days, depending on the type of well.

Although one may say with confidence that operators on the UKCS and NCS have an average well abandonment time between 30-45 days, so-called train-wrecks are seen. This is operations where everything takes the worst turn. In these examples, one may see durations up to 130-140 days for PP&A operations. This leads to an enormous cost increase, and procedures and approaches continually change in order to counteract such incidents.

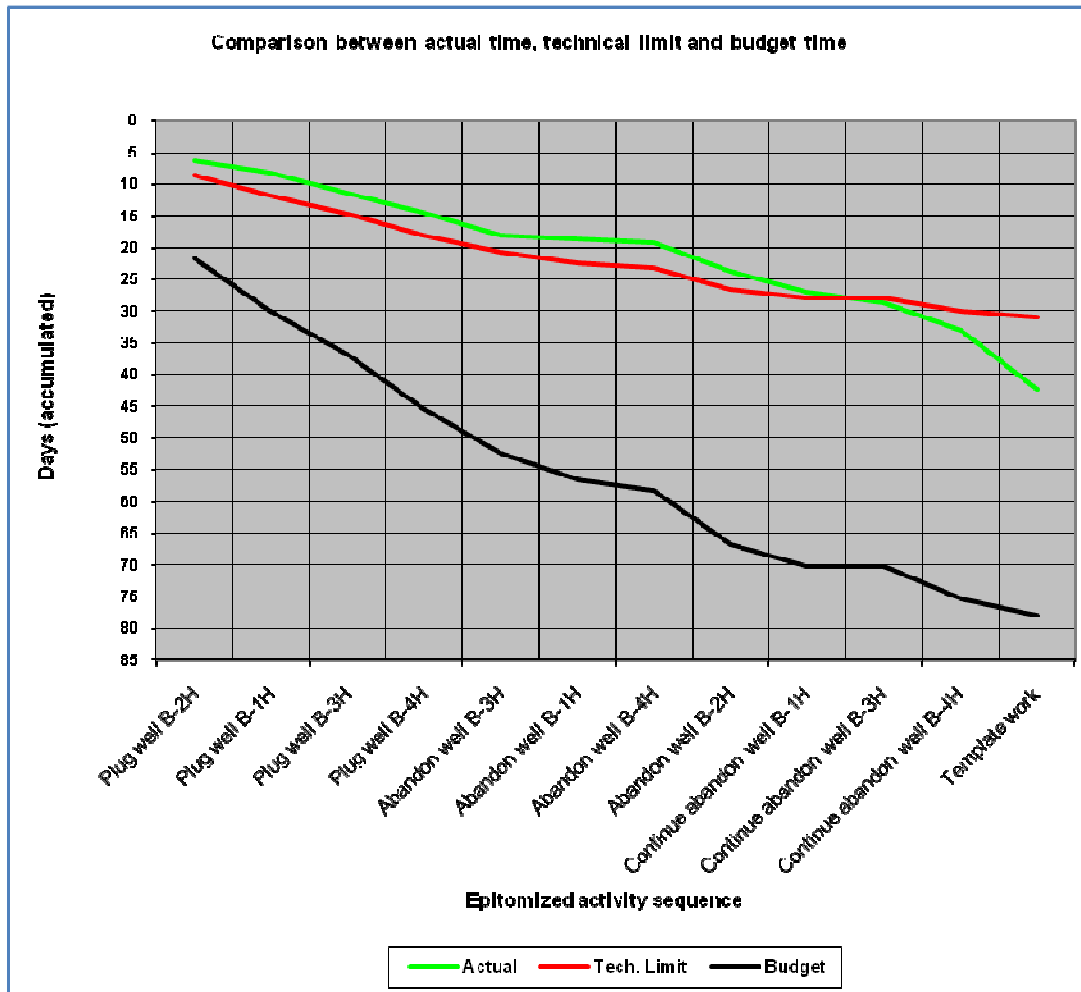


Table 18: Time results from PP&A operation performed by Statoil in 2000-2001.

5.11 Dedicated forums

Attending PP&A forums have the potential of revealing most of the upcoming technological and regulatory developments. In addition many ideas and solutions to problems are presented here. Gaining this valuable insight requires short time compared to personal, single-handed information gathering. It is also a great arena for networking, discussion and understanding. At these gatherings, operators get the chance of proclaiming their need and service providers can get an idea of what they should focus on. In other words it can be mutually beneficial for operators and service providers to attend these forums.

5.12 Doing it right the first time

Experiences from CoPNO on some of their earliest PP&A operations show that they had to re-enter ca. 20% of the wells that they had permanently plugged and abandoned. This re-entering is very costly, and it enables a cost-wise justification of spending some extra time in doing the job correct the first time. Therefore they have started to use proper time when section milling, such that they are able to get proper plugs covering all the possible zones of cross-flow or inflow to the well.

It is also a common saying in the industry that 75% of the time spent on a PP&A operation is spent during Phase 2 of the plugging and abandonment. This implies that future focus on reducing this time would be the smartest cost-wise investment. The fact that Phase 2 constitutes such a large amount of the time spent on the PP&A operations, has to do with the amount of plugs needed to fulfil the secondary barrier requirements. Many fields have several possible sources of inflow or cross-flow, and current requirements state that these must be properly plugged so that no unwanted flow of HC is seen. Perhaps the close future, even the next revision of NORSOK D-010 will change that statement so that it covers unwanted flow of fluid in general, and not only HC. There may be water bearing zones and contaminated water bearing zones which may potentially damage some of the barrier elements, or escape to surface. These should also be plugged properly.

6 Experiences, conclusion and recommendations

The work on this thesis has revealed that the first hypothesis, H_0 , proves true; there definitely exists a potential to reduce the time and costs related to PP&A operations. These potentials are presented in this thesis, and should be considered when planning future PP&A operations.

Furthermore, this chapter will cover some operational experiences made by personnel involved in PP&A operations and some conclusions and recommendations based on the subchapters in the Discussion chapter.

6.1 *Operational experience*

Spending good time when preparing the operation, and going through each involved personnel's responsibility area during the planning phase of the operation is deemed favourable. Creating contingency plans for all the unplanned incidents which may occur during the PP&A operation enables a smoother execution of operations. Experiences from several PP&A campaigns indicate that performing the PP&A operation in batches is positive with respect to operational time. If e.g. 10 wells on a field are to be abandoned, doing Phase 1 of the PP&A operation on all wells prior to proceeding to Phase 2 and 3 is deemed favourable. Finally performing all the cutting and retrieving of wellhead and top section of conductor and surface casing in one batch tends to yield good results time-wise, due to batch learning curve effects.

6.2 *Streamlining operations*

Since PP&A operations already require such a huge proportion of the available rig-time, it is important to streamline the execution of PP&A operations. One examples of this can be: when section milling, use WOC time to clean swarf from BOP. There are many other operational adjustments that can be done in order to enhance the operational part in the PP&A campaign. Experienced personnel learn these "tricks of the trade", and a combination of innovative young minds and the experience of the elders, has a certain potential to enhance the performance of PP&A operations.

6.3 Alternatives to section milling

Section milling is time consuming and complicated operations. Alternatives to section milling should be considered when possible. A typical problem free section milling operation takes from 10-15 days. The use of HydraWash™ in combination with Archimedes™, has a typical operational time at around 5 days, and adoption of alternatives with this potential is advised.

6.4 Waiting with PP&A after first NOCF (Negative Operating Cash-Flow) is seen

It is not always so that a field/well should be permanently plugged and abandoned when the first negative operating cash flow is seen. This is amongst others due to the uncertainty in the fluctuations of the oil price. Bratvold and Begg investigated abandonment decisions and shut-in policy as a function of uncertainty in the oil price [28]. This investigation focused on the decision errors caused by using the “smoothing out” of oil price fluctuations over time. They also focused in the errors caused by restricting the investigation of uncertainty to the uncertainty in the parameters of “smoothed out” of oil price models. In this paper [28] they showed that it is better to wait for a certain amount of time after the first negative operating cash-flow is seen, and how to estimate the length this “waiting time”. In addition they showed how this conclusion is relative insusceptible to the oil-price model parameters. The final, and perhaps most interesting conclusion they made, is that, as opposed to the normal operating procedures, it is more economic to choke back production in times of low oil price. For further investigation on these matters, the reader is encouraged to read this paper on “Abandonment Decisions and the Value of Flexibility”[28].

Another aspect to this subject is that by waiting some amount of time after the first NOCF is seen, new technology or methods may develop which have the potential of increasing production even further. E.g. IOR (Increased Oil Recovery) may unlock possible production potential.

6.5 Learning effect from well abandonment campaigns

As shown in chapter 5.9, there is a potential for learning effect when performing field-wide PP&A campaigns. Since turnkey contracts follow a decreasing, well-defined trend in the well abandonment costs, it is advised to pay extra attention to turnkey contracts when considering contract type.

The fact that learning effects on campaigns can influence the cost of operations is important, and therefore it is taken into account in Statoil's cost estimation model.

However, the learning curve effect may be greatly impaired by the governmental rules and regulations. Hence it is advised that there is paid careful consideration and caution before implementing a regulatory regime that defines timing of well abandonment.

6.6 Alternative plugging materials

Cement has been used since the beginning of the petroleum industry, and is the conventional plugging material. It is also by far the plugging material the industry has most experience with. However, the mechanical properties of cement do not fulfil all the requirements of a PP&A plug stated in NORSOK D-010 and APOS. Perhaps it is due time for a reconsideration of cement? In order for application of alternative plugging materials, facilitation of field application of these materials is needed. Combination of different plugging materials is deemed favourable, as one material's properties may cover the function which the other material does not possess. Combining a plugging material that is impermeable and has good re-shaping abilities with a material that is impermeable, non-shrinking and has good compressive and failure-flexural strength, would give a composite plug that fulfils all the requirements in NORSOK D-010 and APOS. In other words, the results of trying e.g. a combination of Sandaband® and ThermaSet® would be very interesting.

6.7 Engagement in dedicated forums

The engagement in dedicated forums is highly recommended. The participants of dedicated PP&A forums gain a very good overview of the current challenges and technological and regulatory developments in a short time. This has the potential of greatly enhancing the competence concerning PP&A operations for the participants.

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8 Appendix A

8.1 Workflow of the thesis

The work on this thesis has been performed at Statoil ASA's offices at Forus, Stavanger. It has been performed on a daily basis by working from 08.00 – 16.00 every day from the start and until the end.

In the beginning of the planning of the thesis, a “boxology” was made to get an overview of the workflow. The forming of the first hypothesis, “H₀”, was done around the January 26 along with the workflow progression towards the end.

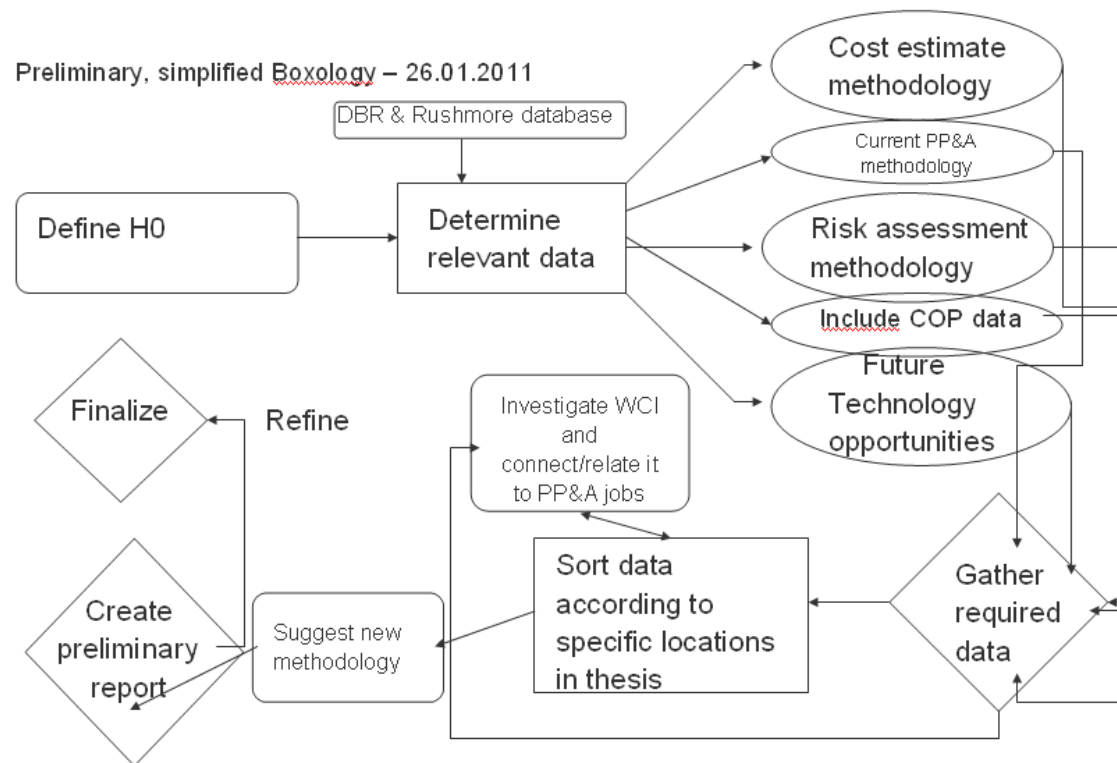


Figure 26: Boxology showing the development of the thesis.

The collection of information concerning PP&A operations was started in January. The author of this thesis was quite unfamiliar with the subject, and did not know how operations like this was approached and performed. Therefore an extensive literature search was initiated. After collecting data concerning PP&A, a hypothesis was proposed. This was discussed with Professor Kjell Kåre Fjelde at the University of Stavanger, and

the team in Statoil ASA which was responsible for issuing the thesis. After this, the hypothesis was revised, and it was suggested that the thesis should cover:

1. Analysis of DDR, Rushmore Reviews, CoPNO and other sources in order to discover potential trends in the FF PP&A campaigns
2. Technological overview in order to find out what current technological approaches that was being made in order to fulfil the objectives in a PP&A operation. Also an overview of the development of new technology which could enhance the performance of PP&A operations should be made.
3. An overview of legal regulations and requirements concerning PP&A activity on the NCS, UKCS and US GoM area should be made. The point of doing this was that the regulations and requirements will in some way affect the way PP&A operations are performed. One idea was that maybe the differences in regulations had some impact on the final cost of performing the PP&A operations in the various regions, and therefore it would be interesting to investigate the legal regimes. Internal requirements and company practice should also be investigated in order to check whether these affected the final cost of PP&A operations.
4. Also, initiatives like dedicated forums, projects and workgroups should be consulted in order to understand how the challenges of PP&A operations are met.

After these subjects had been addressed, the author was advised to choose one of these subjects, and to an in-depth study of it. During the progress of the thesis, and the investigation of the four subjects mentioned above, an in-depth study of the technological approach to PP&A operations was chosen. And since the title of the thesis is "Final Field Permanent Plug and Abandonment – Methodology development, Cost Estimation and Risk Evaluation", one may say that the in-depth study of technological approaches is a part of the methodology development, and thus the main part of the thesis. Since the thesis is open for all viewers, it was also decided to choose an approach of time estimation, seeing

that numbers concerning cost can be sensitive. However, time estimation proves valuable, since it can easily be correlated to cost of PP&A operations both now and in the future. Time data is also of a less sensitive nature than cost data. This thesis' description of time and cost estimation covers the "Cost Estimation" part of the thesis.

In order to complete the objective of deep-digging into the technological approach to PP&A operations, OLF's PP&A forum was attempted to access, but this is preliminary a forum with restricted access. However, the author was invited to OLF's PP&A Workshop 9th June 2011. This enabled for some last-minute polishing of the thesis, and was a good cross-check to ensure that the thesis covered the hottest issues. In addition, the author was allowed to join the SPE's 3rd European Well Abandonment Seminar 29th March 2011 in Aberdeen. This bore fruits with regards to current and future estimation, regulations and methodology. Much valuable insights were gathered there, and some of it has been allowed to be presented in this thesis. A co-operation between the author and CoPNO on the premises of partnership with Statoil ASA has also given much valuable insights concerning technological approaches to PP&A operations and methods of performing cost estimation concerning PP&A campaigns that have been presented in this thesis. An extensive network between the author of the thesis and many of the service providers has been established. This includes many days of company visits with presentation of current and new technology, tailor made for PP&A applications. The author has been in close contact with companies like Sandaband[®], Hydra Well Intervention, WellCem AS and the NCA-group and thus gathered valuable information about smart solutions which can enhance the performance of PP&A operations.

The author has also established a good network in the internal Statoil ASA organization. This has proved very valuable for the development of the thesis, and will also prove valuable post-thesis.

9 Appendix B

Well abandonment program used on Yme over a decade ago:

1. Kill well w/seawater and LCM pill to plug off formation. Observe well.
2. Pull WRSCSSV.
3. If well is stable, run Monolock plug. If loss rate less than 1 m³/hr, run wireline brush and then run PRN plug and prong. If loss rate higher than 1 m³/hr pump new LCM pill. Install piggy back in wireline strings. Test plug.
4. Install WRSCSSV. Inflow test the same.
5. Nipple X-mas tree and BOP.
6. Pull WRSCSSV.
7. Pull Monolock/PRN prong and plug. Install piggy back in wireline strings.
8. Install WRSCSSV.
9. Pull packer free, pull hanger to surface, terminate cables
10. Circulate out oil below packer and packer fluid in annulus.
11. Pull completion until WRSCSSV at surface.
12. Open SSD if swabbing while pulling out.
13. Pull completion.
14. RIH with brush, EZSV packer and circulation valve on 5" DP. Set 9 5/8" cement retainer 50 m above top 7" liner at 3096 m MD. Establish injectivity. Squeeze cement into reservoir. Drop cement on top of retainer, ____ m.
15. Pump slop into well on the way out.
16. Set 9 5/8" bridge plug at 450 m on DP.
17. Displace to weighted mud with H₂S scavenger.

18. Perforate 9 5/8" and 13 3/8" casings below wellhead. Observe. Check communication through both casings by pressure up (expected leakoff at 20" shoe).
19. Cut 9 5/8" casing at 400 m.
20. Cut 10 3/4" tieback casing at 18 m.
21. Retrieve MS seal from wellhead.
22. Retrieve 10 3/4" casing and surface wellhead.
23. RIH with spear and retrieve rest of 10 3/4" tieback casing, disconnected with 7-8 LH turns.
24. If x-over between 10 3/4" and 9 5/8" casings is not retrieved in previous step, run in with MLC retrieving tool and retrieve x-over. LH turns.
25. N/D BOP.
26. Launch ROV in water.
27. Cut 20" production riser at ____ m.
28. Pull 20" x 13 3/8" prod. riser.
29. RIH and release 20" tieback with 4-5 RH turns. POOH with the same.
30. Pull 9 5/8" seal assy - 13-14 LH turns.
31. Pull 9 5/8" casing.
32. Cut 13 3/8" csg at 350 m.
33. POOH with 13 3/8" casing including 13 3/8" seal assy.
34. Place a cement plug 450 m - 150 m. Cement volume is estimated to 41.3 m³
35. Cut and pull 20x30" casing 3-5 m below seabed.

10 Appendix C

HydraWash™ and Archimedes™ operational procedure

A typical operational procedure for this combination tool is as follows:

1. Perforate 50m interval with big hole charges (0.30"-0.40" ID), POOH
2. RIH w/Hydrawash
3. Break circulation at top of perforations
4. RIH to TD
5. POOH to top perf
6. Drop 1 ½ " ball (close the bypass at the nose of the tool)
7. Blank test – integrity test of Hydrawash
8. Wash from top perforation to bottom perforation (6-18hrs)
9. Wash from bottom perforation to top perforation (±6hrs)
10. RIH to TD
11. POOH while pumping spacer
12. RIH to TD, Drop 1 ¾" ball
13. @ TD, release HydraWash™ → converts to a cement stinger
14. Pump plugging material
15. POOH w/cement stinger to above TOC
16. WOC
17. Tag top of plug (cement)
18. POOH
19. WOC → pressure test

Appendix D - Random check list of reporting quality concerning well abandonment in DBR					
FIELD	Well name	Well type	PP&A report	Comment	Impact on time and cost estimation
Gullfaks	34/10-A-18	Injection	Appears OK	None	None
	34/10-B-42-E	Production	Not OK	Found in P&A section "starting to drill new hole" - Sidetrack preparation under P&A. from 2-4.12.2003	Overestimation of time
	34/10-A-48-B (T2)	Injection	Not OK	In the last report before "preparing to sidetrack", the day was spent on making up 5 1/2" DP and RIH with Whipstock assembly	Overestimation of time
	34/10-C-52	Observation(NPD)/Production(DBR)	Not OK	Seems like section "Permanent P&A" is used for sidetracking. In other words this seems like an open hole sidetrack operation	Overestimation of time
	34/10-B-14-A	Injection(NPD)/Production(DBR)	Not OK	PP&A items are under "other", "WL tractor", "Pull Completion" etc. In addition, some TP&A sections appear amidst the PP&A sections, while PP&A overlaps TP&A's items.	Underestimation of time
Snorre	34/4-L-2-H	Injection	Not OK	Many items concerning kick-off plug and drilling of hole in the permanent P&A section	Overestimation of time
	34/4-C-7-H	Observation(NPD)/Production(DBR)	Not OK	Some PP&A reports contain "maintenance work on D-99", kick off drilling on PP&A section	Overestimation of time
	34/4-C-4-H	Production, but in NPD, status is "producing". Mixed with C-4-H T2?	Appears OK	Hard to comprehend with all the unfamiliar abbreviations, but seems to be ok.	None
	34/4-D-1-H	Production	Appears OK	None	None
	34/4-D-2-H	Production	Not OK	Kick off under PP&A section, diagnostic run under 8 1/2"	Overestimation of time
Statfjord	33/9-C-26-A	Production	Not OK	Section milling, setting of whipstock and opening for sidetrack under PA section	Overestimation of time
	33/9-C-11-A	Injection	Not OK	WL operation for preparation of PP&A under WL section, Sidetrack and continuation of operation on other well under P&A section	Overestimation of time
	33/9-C-37-A	Production	Appears OK	None	None
	33/9-C-37	Production	Not OK	Appears that setting of whipstock, milling window and 5-10m new formation is recorded under P&A section	Overestimation of time
	33/9-C-12-C	Production	Appears OK	None	None

11 Appendix E

The background data for Figure 25.

<i>Contract Type</i>	<i>Parameter (Unit)</i>	<i>[1] Well</i>	<i>[2-4] Wells</i>	<i>[5-9] Wells</i>	<i>[10-15] Wells</i>	<i>[>15] Wells</i>
ALL	Average Cost/Well (\$1000/well)	152	154	88	64	48
	Standard Deviation, Average cost /well	14	14	12	11	11
	Number of Jobs	116	77	36	15	12
	Number of Wells	116	77	36	15	12
Turnkey	Average Cost/Well (\$1000/well)	116	141	79	103	96
	Standard Deviation, Average cost /well	121	132	50	51	-
	Number of Jobs	63	42	8	2	1
	Number of Wells	63	135	59	26	17
Dayrate	Average Cost/Well (\$1000/well)	194	169	90	58	44
	Standard Deviation, Average cost /well	168	101	75	41	40
	Number of Jobs	53	35	28	13	11
	Number of Wells	53	101	230	155	317

Table 19: The impact of scale on P&A cost. Figures taken from[27].

12 Appendix F

	C	D	E	F	G	H	I	J	K	L	M	N	O	P
	Description of Hazard	Risk rating	Freq. / Prob	Impact / consequence	Action/ What to do to solve	Risk type (Cost / Safety / Env)	Contingency (x)	Responsible	Action due date	Action completed	What is/ are the contingency	Size of risk covered by contingency (kHOK)	Cost of implementing contingency (kHOK)	Status of contingency
1														
2	Low injectivity A-3	10	2	3	Pump cement	c	x	IK, GS	06.des.00	19-des-00	Run Monolock (deep set plug). If cemented, run WL. Lurium fluid for tractor			
3														
4	Pressure in other annulus when pumping	10	2	3	Set plugs under packer	c	x	BØ	22.des.00	20-des-00				
5	Weather delays	10	1	3	Weather forecast actively used	C		JES/PS		ongoing	Observation ROV on board / Identify guidewire			
6	Rig equipment failure – pipe handling, etc	10	2	3	Set program aside - POOH ASAP	C				ongoing				
7	Condition of casing	10	2	3	EZSV must be set over last set production packer	C		BØ	30.jan.01					
8	Pull template up off sea bed – unable to retrieve casing / damage template	10	2	3	Remember that A1 with SG-6 is locked	C		HP	08.des.00	20-des-00				
9	Unable to lift template	100	2	2	Have ROV make a new inspection video. Perform a separate risk analysis	C		HP	15.feb.01					
10	Cement on template needs to be broken up with explosives	10	2	3	Wait till after productions shutdown - if legal. Subject will be treated in separate risk analysis together with risk F1	C	X	HP	15.feb.01		Make back up plan (cutting, parting, welding, etc). Diving vessel must be available			
11	Conflict between operations	10	2	3	Communication between units. Plan well	C		GS	ongoing	ongoing				
12	Weather	10	2	3	Be observant on weather forecast. Plan for bad weather	C		OAV		ongoing				

Table 20: Risk register covering the highest risk ratings in a real project.