University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: Master of science in Industrial Economics/ Contract Administration	Spring semester, 2017 Open access
Writer: Stian André Wittberg	………………………………………… (Writer's signature)
Faculty supervisor: Dr. Mahmoud Khalifeh External supervisor: Maxime Maouche	
Thesis title: Expanding the Well Intervention Scope for an Effective P&A Operation	
Credits (ECTS): 30	
Key words: Plug and Abandonment (P&A) Rigless Through tubing Well intervention Case study Electric plasma miller Thermite plug	Pages: 118 + enclosure: 23 pages Stavanger, June 14th 2017

Expanding the Well Intervention Scope for an Effective P&A operation

Master's thesis

by

Stian André Wittberg

Universitetet i Stavanger

Faculty of Science and Technology

Department of Industrial economics, risk management and planning

2017

Abstract

Over 2500 wells on the Norwegian Continental Shelf (NCS) will at some point have to be permanently plugged and abandoned. As the drill rig rate contributes to 40-50% of the total plug and abandonment (P&A) cost, the potential savings in shifting operations towards a rigless approach could be significant. The main objective during a P&A operation is to restore cap rock functionality, by creating a cross-sectional barrier. The conventional way of plugging wells on NCS is to use a rig, to allow pulling tubing, section milling or perforate, wash and cement operations to be executed.

This thesis presents an alternative approach to P&A using well intervention equipment in combination with some emerging high-energy technologies intended for rigless P&A. Wireline and coiled tubing with associated equipment and tools are used together with an electric plasma miller and/or thermite to create a cross-sectional barrier in a through tubing and X-mas tree P&A operation. A case study is presented where three wells are plugged using a rigless approach. The wells have an increasing P&A complexity, where lack of annular barrier traditionally requires a rig.

The case study identified several challenges with the presented rigless approach. A through tubing operation will leave the tubing as a major restriction in the well. All tools have to pass through the tubing before reaching the required plugging interval. Azimuthal bond logging tools intended for logging production casing cement will have particular difficulty passing tubing of 5-1/2" and smaller. Additionally, placing enough thermite to comply with current NORSOK D-010 specifications was found challenging. New revisions of NORSOK D-010 should allow the implementation of new technology and rigless P&A to open up for a leaner approach to P&A. The majority of the wells studied were not fully suited for a complete rigless P&A operation, but the approach could be used to install permanent reservoir barriers. By completing parts of the plugging operation using well intervention equipment, the P&A scope for a rig could be minimized and thereby potentially saving cost.

Acknowledgement

This thesis is submitted in fulfillment of the requirements for the degree of Master in Science at the University of Stavanger. It has been written at the offices of Archer in Stavanger, Norway.

I would like to thank Egil Thorstensen for offering to assist me in the writing process. His enthusiasm on the topic and the thesis has motivated me throughout the semester. Our discussions and his feedback resulted in a more reflected and thorough thesis. Thanks for sharing network and putting me in contact with the right people.

I would also like to thank Dr. Mahmoud Khalifeh, my supervisor at the University of Stavanger. I am grateful that he accepted to supervise my work, although I was not part of the Institute of Petroleum Technology. His guidance and feedback throughout the semester has helped me becoming a better academic. He always had an open door and prioritized meetings with his master students on short notice. Also, when I wanted to choose the easy way out, he always challenged me not to. For example, when I wanted to use imaginary wells for the case study, he insisted in using real well data, which definitely brings more credibility to the thesis.

Thanks to Roy Kristiansen at Archer for providing me with a challenging topic, but still giving me freedom to take the thesis in the direction I wanted. I am also grateful that Archer provided an office with excellent working environment for carrying out the project. I would also like to thank Maxime Maouche, my external supervisor at Archer, for good discussions and assistance when needed.

In addition I would like to thank Lars Hovda and Paal-Espen Johnsroed in ConocoPhillips, Martin Straume and Luca Carazza in AkerBP, Ørjan Finnseth in Repsol and Tore Fjågesund in Wellbarrier for their contribution to the thesis. Without their contribution the project could not have been carried out.

Finally, I would like to thank my wife Linn, for her support and patience throughout the writing process.

Stian A. Wittberg

Stavanger, Norway

June 2017

Table of Contents

List of Figures

List of Tables

Abbreviates

A:	Ampere
ASV:	Annulus safety valve
BHA:	Bottom hole assembly
BOP:	Blow out preventer
bpm:	Barrels per minute
CBL:	Cement bond log
CIV:	Chemical injection valve
Csg.:	Casing
CT:	Coiled tubing
DECT:	Downhole electric cutting tool
DHPG:	Down hole pressure gauge
DHSV:	Down hole safety valve
DP:	Drill pipe
FIT:	Formation integrity test
Fm.:	Formation
GLV:	Gas lift valve
HC:	Hydrocarbon
HUD:	Hold up depth
ID:	Inner diameter
JIP:	Joint industry project
kg:	Kilo gram
LOT:	Leak off test

LPM:	Liters per minute
m/min:	Meters per minute
m:	Meter
MD:	Measured depth
MFC:	Multifinger caliper
MJ:	Mega joule
MW:	Megawatt
NCS:	Norwegian continental shelf
NOG:	Norwegian Oil & Gas Association
NOK:	Norwegian kroner
NPD:	Norwegian Petroleum Directorate
NUI:	Normally Unmanned Installation
OBF:	Overburden formation
OD:	Outer diameter
P&A:	Plug and abandonment
PAF:	P&A Forum
PCE:	Pressure control equipment
PDM:	Positive displacement motor
ppf:	Pounds per foot
PSA:	Petroleum Safety Authority
PT:	Pressure test
PWC:	Perforate, Wash & Cement
R&D:	Research and development
RCT:	Radial cutting torch

RKB:	Rotary kelly bushing
ROP:	Rate of penetration
s:	Second
SBT:	Segmented Bond Tool
SCP:	Sustained casing pressure
SPF:	Shot per foot
SPM:	Side pocket mandrel
SRR:	Steel removal rate
TD:	True depth
TOC:	Top of cement
TT:	Through tubing
UiS:	Universitetet i Stavanger
V:	Volt
VDL:	Variable density log
W:	Watt
WBE:	Well barrier element
WBM:	Water based mud
WBS:	Well barrier schematic
WEG:	Wireline entry guide
WHP:	Well head pressure
WL:	Wireline
WOC:	Wait on cement
XT:	X-mas tree

1. Introduction

1.1 Introduction to P&A

Over 2500 wells on the Norwegian Continental Shelf (NCS) will at some point have to be permanently plugged and abandoned (Spieler and Monge Øia 2015). Well plug and abandonment (P&A) activities are estimated to contribute up to 50% of the total decommissioning cost of oil & gas fields (Oil & Gas UK 2016). Cost estimates as high as 900 billion Norwegian kroner (NOK) have been presented based on the P&A operations taking in excess of 40 years to complete using today's technology (Myrseth et al. 2017). Because of the current Norwegian tax regulations the state will have to indirectly pay 78% of the upcoming P&A cost. Although most of the attention has focused on the time and cost of P&A, it is important to remember that the primary objective of a P&A operation is to restore the cap rock functionality with a barrier, which can withstand for eternity.

1.1.1 General

By combining some of the definitions in NORSOK D-010 (2013a) and Oil & Gas UK (2012) one could say that a permanent plug and abandonment operation is: A sequence of planning and execution of tasks, which are carried out to secure a well by installing required well barriers, permanently sealing a source of inflow to obtain a well status where the well will not be used or re-entered again. A well can be temporarily or permanently plugged and abandoned. In this thesis, P&A is referred to permanent P&A unless otherwise specified.

When working in accordance with NORSOK D-010 (2013a) the key feature is the annular barrier. This needs to be in place and verified. If this is not the case, a series of activities must be executed to get access to the annulus to establish a cross-sectional barrier.

A major operator on the NCS has implemented the "P&A square" to visualize the process and steps needed to obtain a permanent well barrier, Figure 1.1 (Hovda 2017).

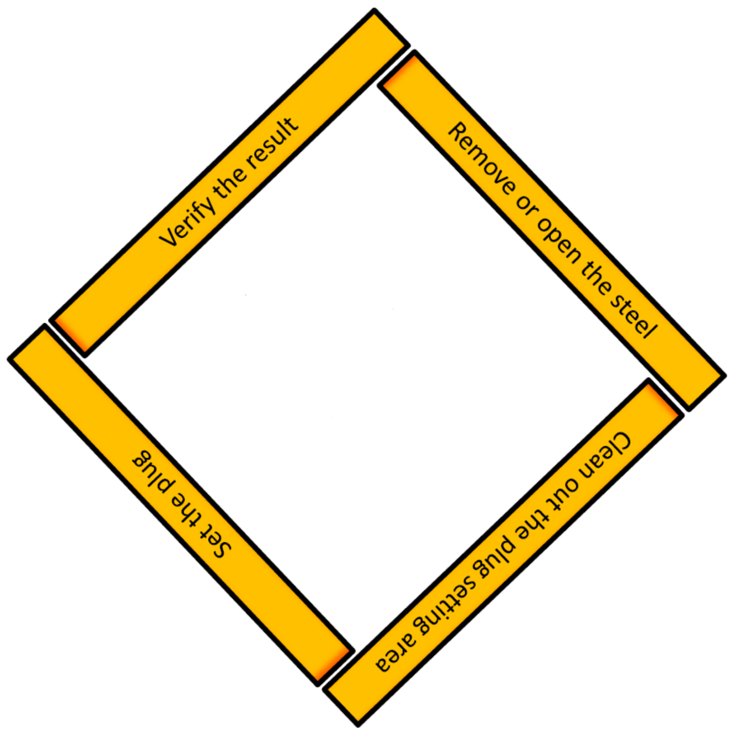


Figure 1.1: P&A square (Hovda 2017).

Each of the elements in the P&A square, with explanation of possible operations to achieve the objective, are shown in more detail in Table 1.1.

Table 1.1: Tabulated P&A square

P&A square objective	**Possible activity to obtain objective**
Remove or open steel	• Pull tubing • Section mill casing to access formation • Perforate casing to access formation
Clean out the plug setting area	• Clean out run after section mill • Cup or Jet wash behind perforations
Set the plug	• Cementing
Verify the result	• Pressure test • Dress off and tag • Drill out and log after PWC operation

With the requirements listed in NORSOK D-010 (2013a) and the current technologies most P&A operations are drill pipe (DP) based to complete all sides of the P&A square. Some through tubing (TT) technologies are available, but none can yet do the whole operation. Although TT technologies can place the reservoir plugs in some wells, in most cases the intermediate plugs still need a rig to complete the whole P&A square. The P&A operations can be divided into three phases as presented in Table 1.2 (Oil & Gas UK 2012).

Table 1.2: P&A phases. Adapted from Oil & Gas UK (2012)

Phase	Operations included
Phase 1 - Reservoir abandonment	Primary and secondary permanent barriers are set to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. Complete when the reservoir is fully isolated from the wellbore.
Phase 2 - Intermediate abandonment	Includes: milling and retrieving casing, and setting barriers to intermediate hydrocarbon or water bearing zones and potentially installing near-surface cement. The tubing may be partly retrieved, if not done in phase 1. Complete when no further plugging is required.
Phase 3 - Wellhead and conductor removal	Wellhead and conductors are cut and removed.

As phase 2 requires a rig for pulling tubular and milling, the rig is commonly used for phase 1 as well. The drilling rigs choice will be dependent on infrastructure, whether to choose the existing platform drilling derrick (if installed), a modular rig or a jack-up rig. In the continuation of this thesis conventional P&A will refer to a jack-up rig P&A operation.

The cost estimations mentioned above are based on a well taking 35 rig days on average to complete (Myrseth et al. 2017). In the past decade, great improvements have been done with regards to the time spent on a P&A operation. From the section milling based operation in 2008 taking 65 days on average (Scanlon et al. 2011), to the perforate, wash & cement (PWC) presented by Ferg et al. (2011) reducing the plug setting time from 10.5 days to 2.6 days, and ending up with the Statoil P&A statistics for 2016 with an average of 17.6 days per well (Hemmingsen 2017). The numbers presented might not be fully representative for the NCS as a whole, but provides a picture of the improvements made. A key question in the P&A industry is:

What is the technical limit for a rig based P&A approach, and will a TT option be competitive on time and cost once the technical limit is reached?

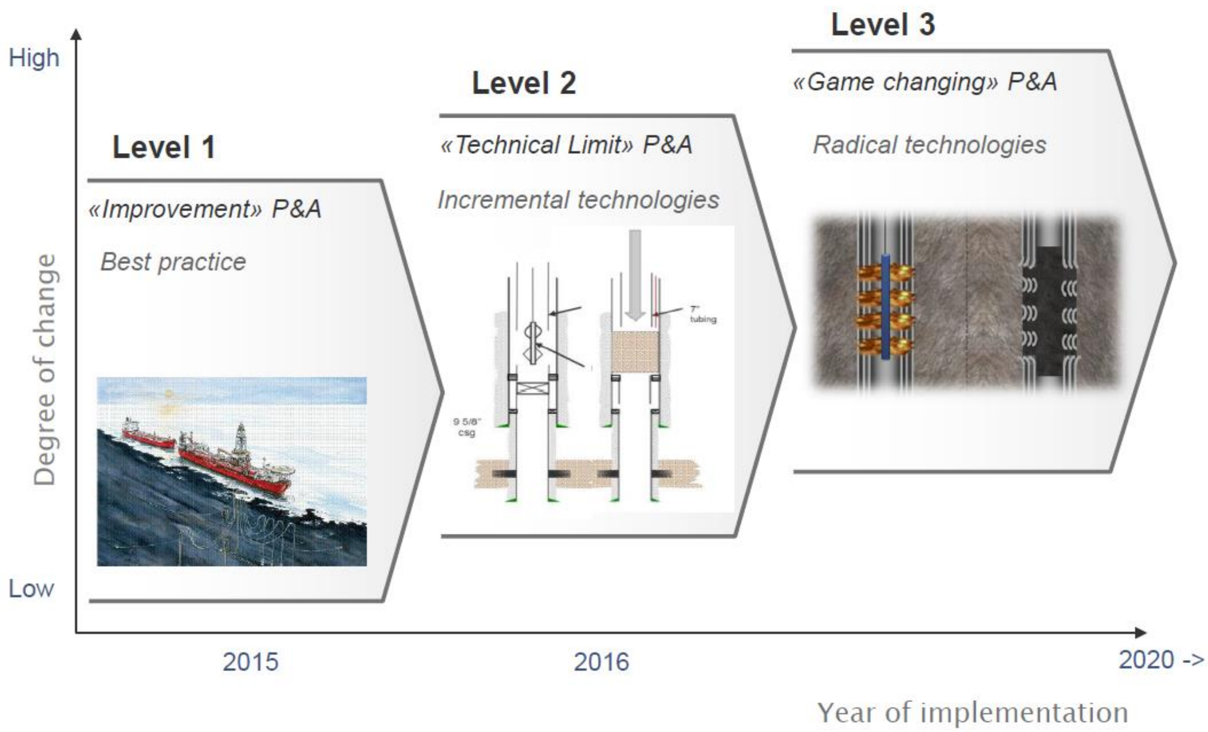


Figure 1.2: Statoil P&A improvement plan (Hemmingsen 2017)

Figure 1.2 illustrates Statoil's three levels of improvement in P&A.

- Level 1 *Improvement*: Finding the best practice and procedures for conventional P&A operations. Improving efficiency.
- Level 2: *Technical Limit:* Incremental technologies, finding a more effective way of completing a task. PWC is a good example where time used for P&A is reduced drastically.
- Level 3: *Game changing:* Radical technologies will include some of the solution proposed for rigless P&A operations.

As technology improves and a *Game changing* approach becomes commercially viable, several wells could possibly be plugged TT. By categorizing well plugging complexity, as done by Statoil in Figure 1.3, candidate wells for a rigless approach will emerge. Approximately 45% of the wells are categorized as "simple", while 25% are regarded "medium" complexity. The major part of these wells could possibly be plugged utilizing a rigless approach. More complex wells might still need a rig also in the future.

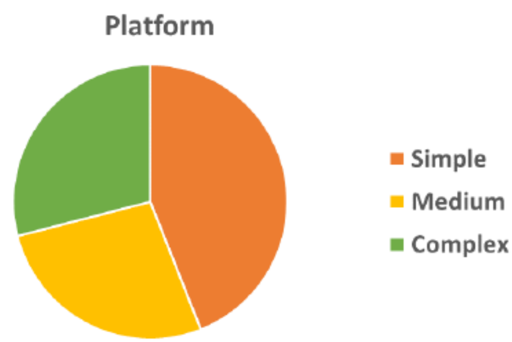


Figure 1.3: Statoil's well configuration complexity pie chart with regards to future P&A. Pie showing Statoil platform wells only (Hemmingsen 2017)

1.1.2 Norwegian Oil & Gas Association – P&A Forum

The Norwegian Oil & Gas (NOG) P&A Forum (PAF) was established in 2009 after an initiative from a single operator hosting a P&A workshop (Straume 2012). One of PAF's focus areas is improvement in technical solutions for upcoming P&A operations. In 2015 the *Roadmap for New P&A Technologies* was presented at the PAF Seminar (Straume 2015). The roadmap illustrates the focus areas for the coming years with regards to technology innovation. *Well intervention technology for P&A* and *Rigless P&A* are some of the main areas of improvement, as highlighted in Figure 1.4. The potential savings could be significant as the rig rate contributes to 40%-50% of the total P&A cost (Straume 2016). With that in mind, this thesis will focus on using well intervention technology to P&A wells without the use of rig. Both existing and emerging technologies, such as futuristic high energy solutions and extreme concepts, will be presented in chapters 2 and 3. The aim is to plug wells through X-mas tree (XT) and through tubing. Leaving the X-mas tree in place will enable it to be used as a part of the well barrier envelope during P&A operations.

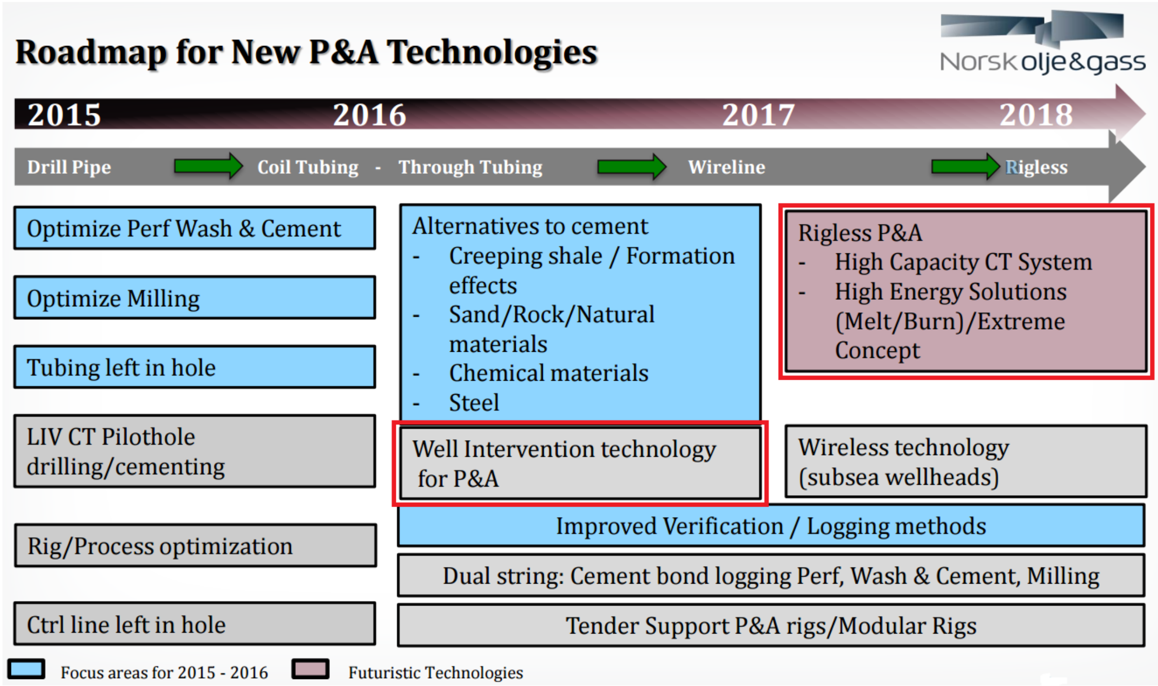


Figure 1.4: PAF Roadmap for new P&A technologies. *Well Intervention technology for P&A* and *Rigless P&A* highlighted and will be further investigated throughout this thesis (Straume 2016)

1.1.3 NORSOK D-010 and requirements

Before suggesting through tubing P&A solutions one needs to have an in-depth knowledge of the current regulations and requirements. The regulations refer to norms and industry standards indicating the features which solutions are expected to meet as a minimum (Gundersen 2017). One such industry standard is NORSOK D-010 (2013a), *Well integrity in drilling and well operations*. Compliance with NORSOK D-010 (2013a) will also comply with the Norwegian regulations. Similarly Oil & Gas UK (2012a) has implemented a P&A guideline called *Guidelines for Suspension and Abandonment of Wells*. These standards and guidelines are essentially similar and aim for the prevention of (Khalifeh 2016):

- Hydrocarbon and water leakage to the surface
- Hydrocarbon movement between strata
- Contamination of water-bearing zones
- Pressure breakdown (fracture initiation) of shallow formations.

As this thesis will review P&A operations in Norway the following sections will focus on the P&A barrier requirements set in NORSOK D-010 rev. 4 (2013a).

1.1.3.1 Well barrier

To achieve the objectives listed in the above section, it is necessary to install a well barrier. A well barrier is an envelope of one or several well barrier elements. A well barrier element (WBE) is a physical element which in itself does not prevent flow, but in combination with other elements will form a well barrier. The well barriers shall be independent of each other and one should avoid having common WBEs to the extent possible. Barriers used in P&A shall have a specific set of characteristics, and elastomers are not allowed as sealing component (NORSOK 2013a).

NORSOK D-010 (2013a) states that there shall be minimum two barriers for hydrocarbon bearing formations and in abnormally pressured formations with potential to flow to surface. These two barriers are referred to as primary and secondary barrier, as illustrated in Figure 1.5. Primary and secondary barrier is defined as; first-, and second well barrier that prevents flow from a potential source of inflow, respectively (NORSOK 2013a). A simpler way to describe this is; Primary: in direct contact with the pressure, Secondary: "Your last defense" (Fjågesund 2017). The reason for calling it the last defense is that in many well operations several barriers exist that can act as secondary barriers, but only the last defense is listed and defined as a secondary barrier. For example in a drilling well control situation, in most cases one can close the annular barrier to regain control, but only the shear and seal ram is defined as the secondary barrier.

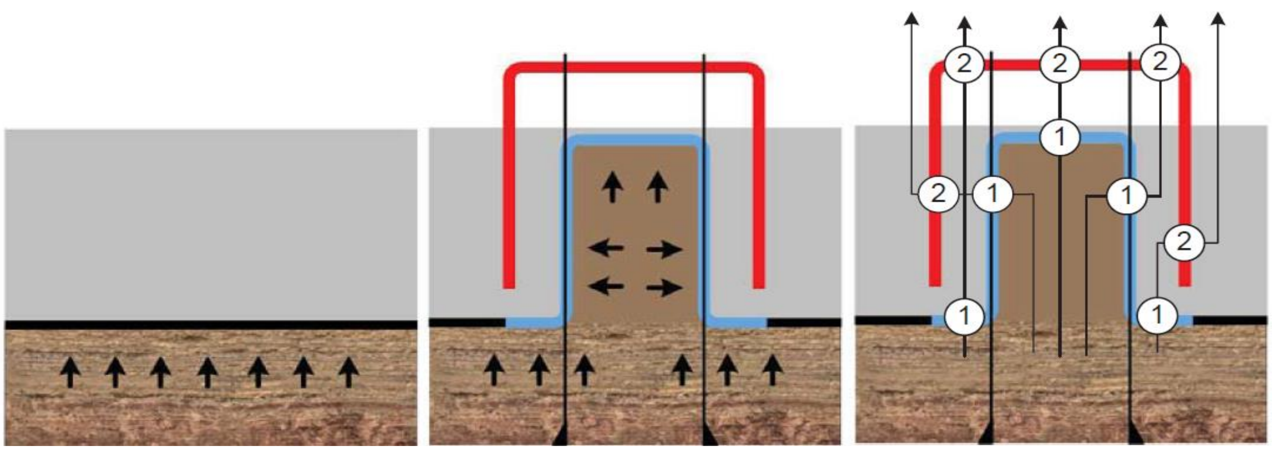


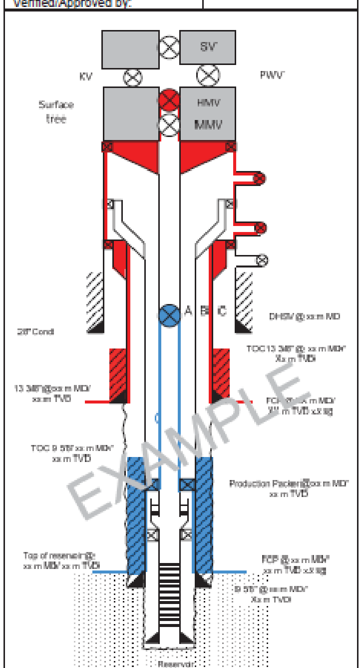
Figure 1.5: The two barrier philosophy is often referred to as "Hat over hat principle". The figure shows the secondary barrier as a red hat over the primary barrier blue top hat (Fjågesund 2017).

1.1.3.2 Well barrier schematic

A well barrier schematic (WBS), illustrated in Figure 1.6, is used to define the well barriers in any phase of a well life cycle. The WBS shows all WBE in place, their acceptance criteria and monitoring and/or verification method (NORSOK 2013a). In addition, it shows the envelope present for both the primary (blue) and the secondary (red) well barriers. The well barrier schematics have several advantages (Fjågesund 2017):

- Clear description of WBE and envelopes
- Clear graphics will help discussions and to see challenges
- Clear description of qualification and monitoring methods
- Consistent graphics and language
- Common understanding, everyone sees the same picture
- Document compliance

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



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

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

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

Figure 1.6: Example of a well barrier schematic (NORSOK D-010 2013).

1.1.3.3 Well barrier requirements in P&A

When designing a P&A well barrier, it shall withstand the maximum differential pressure to which it may become exposed to. In addition it needs to be pressure tested and tagged, as tabulated in Table 1.3. According to NORSOK (2013a) a permanently abandoned well shall be plugged with an eternal perspective with regards to chemical and geological processes and re-charge of formation pressure.

A full cross-sectional barrier is one of the main principles when plugging wells. The barrier shall extend all the way from the formation, including all annuli, and sealing both horizontally and vertically as shown in Figure 1.7 (NORSOK 2013a). It is important that the barrier is placed adjacent to an impermeable formation with sufficient formation strength to withstand maximum anticipated pressure. Formation strength data is collected during the drilling phase by performing leak off test (LOT) or formation integrity test (FIT). Another important note is the removal of downhole equipment to achieve a full cross-sectional barrier. Control lines and cables shall not form a part of a permanent well barrier (NORSOK 2013a). This requirement along with the verification of annular barrier are the main challenges when aiming for rigless and TT P&A.

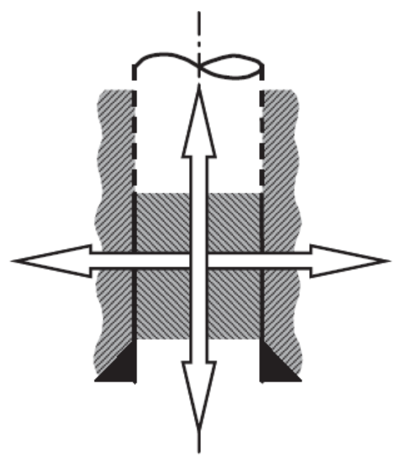


Figure 1.7: Cross-sectional barrier sealing both vertically and horizontally (NORSOK 2013a).

External WBE. To obtain a cross-sectional barrier one of the key challenges when working in accordance with NORSOK D-010 (2013a) is the annular barrier and its verification. It is accepted to use the same casing cement as a WBE in both primary and secondary barrier, as long as it is logged and verified with 2 x 30m measured depth (MD) intervals of bonded cement. If the cement is not logged, the requirement is 50m with sufficient formation integrity at the base of the interval. If sustained casing pressure is observed, the seal of the casing cements shall be verified (NORSOK 2013a).

Internal WBE. The internal barrier plug shall be placed over the same area as the external barrier to create a cross-sectional barrier. A minimum of 50 m is to be set when using a mechanical plug as foundation for the cement plug. It is possible to use a continuous cement plug, sometimes referred to as a "back-to-back" plug, as both primary and secondary barrier inside the casing as well. In these cases the plug is called a common well barrier element. A continuous cement plug, as illustrated in Figure 1.8, will have to be drilled out until hard cement is confirmed for plug verification (NORSOK 2013a).

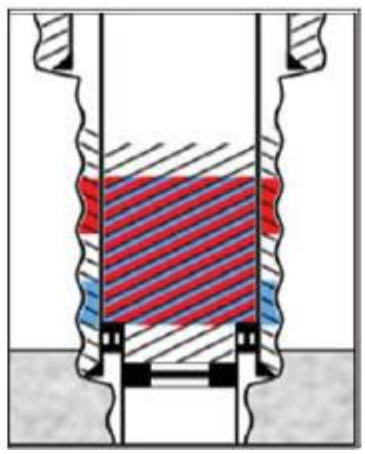


Figure 1.8: Common well barrier – cement plug (NORSOK 2013a).

Table 1.3 lists requirements set in NORSOK D-010 (2013a) for cement WBE. The table will help determine if a rigless approach could place a barrier according to the given standard. With the table in mind the next section will present how a typical NCS platform well is permanently plugged using a jack-up rig.

Table 1.3: Summary of P&A WBE requirements and key notes stated in the Element Acceptance Criteria (EAC) (NORSOK 2013a):

External WBE		Length requirement	Verification method	General requirements
Annular Cement	Single barrier	50m MD	Displacement calculations from primary cement job	Placed above a potential source of inflow. Formation integrity shall exceed the maximum expected pressure at base of each interval
		30m MD	Bond logs	
	Dual barrier	2 x 50m MD	Displacement calculations from primary cement job	
		2 x 30m MD	Bond logs	
Internal WBE		**Length requirement**	**Verification method**	**General requirements**
Open hole cement plug	Single barrier	100m MD	Tagging	Minimum 50m MD above any source of inflow
	Single barrier in transition from open hole to casing	100m MD	Tagging and pressure testing (PT)	Minimum 50m MD above and below casing shoe. PT to 70 bar above LOT
	Dual barrier	2 x 100m MD with 50m MD into the casing	Tagging and PT	Set on a foundation (True depth (TD) or a cement plug). PT to 70 bar above LOT
Cased hole cement plug	Single barrier	50m MD if set on mechanical/cement plug as foundation, otherwise 100m MD	Only tagging if set on pressure tested foundation, otherwise tag and PT	
	Dual barrier	2 x 50 m MD	Drill out cement until hard cement confirmed.	Set on a pressure tested foundation.
Open hole to surface	Single barrier	50m MD if set on a mechanical plug, otherwise 100m MD	Tagging and PT	Pressure test to 35 bar

1.2 Conventional approach to P&A in Norway

The requirement for a cross-sectional barrier and the verification criteria will, in most P&A operations, reveal the need of a rig. As there is no dual-string casing cement (annular barrier) logging tool qualified, the production tubing has to be pulled to access the casing in question (Moeinikia et al. 2014). Another reason for pulling tubing is the control lines or cables connected to downhole pressure gauge (DHPG) or other downhole equipment needs to be removed. They shall not form part of a P&A plug as stated in section 1.1.3.3. If there is no annular barrier present in the desired plug setting interval then either section milling or perforate, wash & cement (PWC) technology must be applied to achieve the desired cross-sectional barrier (Ferg et al. 2011). Both section milling and PWC are rig based technologies in need of torque, relatively high axial load capacity and fluid circulation for hole cleaning. Figure 1.9 shows a jack-up rig skidded over a platform for P&A purposes.

Figure 1.9: Rowan Gorilla P&A operation on Ekofisk A 2016 (Hovda 2017)

In a platform environment with a vertical XT the XT needs to be replaced with a drilling BOP before any rig based P&A operation can commence. As the XT is a part of the barrier envelopes during the production phase, a series of activities needs to be executed before it can be replaced. This operation, performed to comply with the two barrier philosophy, could be referred to as a *pre P&A phase* or *secure well for P&A.* This part of the operation is not specified in UK Oil & Gas (2012) P&A phase coding, Table 1.2.

During batch platform P&A, the *pre P&A phase* is typically a stand-alone well intervention operation. An advantage of stand-alone preparations for P&A is that the rig is free to do other work meanwhile, or to arrive at a later stage to continue the P&A operation. Wireline can be used to prepare the well for the planned P&A by setting a series of plugs and cutting the tubing. The primary barrier when nippling up the drilling BOP could either be obtained by bullheading cement through XT and tubing to squeezing perforations, or by setting a bridge plug in the tail pipe. A potential step list for mentioned operation is listed below:

- Bullhead seawater or kill fluid into the well.
- Bullhead cement to the reservoir and liner interval.
- Pressure test cement plug.
- Rig up wireline (WL)
- Drift well to hold up depth (HUD)
- Optional: Run a multifinger caliper (MFC) for well diagnostics (Moeinikia et al. 2014)
- Optional if cement plug does not qualify as barrier: Set bridge plug in tail pipe below production packer. Pressure test plug
- Punch and cut tubing above production packer
- Displace annulus to seawater or kill fluid
- Set shallow “pump open” bridge plug and test same
- Rig down WL

The well is now ready for phase 1-3 of the P&A operation. A rig will be skidded over the well and a drilling BOP nippled up before commencing. WBS examples with the well status before and after the pre-P&A phase, before phase 1 and after phase 3 can be found in the Appendix A through D, respectively. These WBS also include tubular sizes corresponding to the step list.

- Nipple down XT, nipple up and test drilling BOP
- Displace well to kill mud
- Pull tubing
- Log annular barrier in 9 5/8” production casing
- Run 9 5/8” clean out run

- Optional if no annular barrier in place: PWC or section mill 9 5/8”
- Set primary and secondary reservoir plug
- Set primary and secondary intermediate plug
- Cut and pull 9 5/8” casing (surface plug depth)
- Log 13 3/8” annular barrier if not already verified
- Run 13 3/8” clean out run
- Optional if no annular barrier in place: PWC or section mill 13 3/8”
- Set surface plug
- Cut and pull casing and conductors subsea

A similar P&A procedure is also presented by Moeinikia et al. (2014), although for a subsea well from a semi-sub rig most of the subsurface activities will be the same for a platform well. A list of advantages and limitations on rig based approach to phase 1-3 P&A are presented in Table 1.4.

Table 1.4: Jack-up rig based P&A advantages and limitations.

	Advantages	Limitations
Jack-up rig P&A operation	• High axial pulling capacity for pulling tubular • Torque capability for steel removal • Pumping capability for clean out runs and debris transportation • Mud system to handle open hole conditions (pore pressure/hole stability) • Brings its own infrastructure, deck space, accommodation etc. • Efficient at rig activities like tripping pipe	• Cost • High rig cost will lead to cost of having backup equipment for all contingencies on site (overhead cost) • Mobilization/demobilization time • Availability depending on market

1.3 A revolutionary approach to P&A

A rigless through tubing approach could be a cost effective solution for a large portion of the upcoming P&A operations on the NCS. Fit for purpose P&A, based on the P&A operation complexity, will according to Statoil be a focus area in the future (Hemmingsen 2017). Different P&A approaches are used for different wells, and some of the wells categorized as simple in the configuration complexity pie chart Figure 1.3, could be candidates for a rigless approach. The main objective of a P&A operation is to place cross-sectional barriers and verify them. To be able to verify the annular barrier, access to the casing in question is needed. The production tubing needs to be removed somehow downhole without pulling it. Another solution could be to create a completely new cross-sectional barrier, without use of the existing annular WBE. Both these approaches could be obtained using technology in the *Rigless P&A; High energy solutions* box of the NOG technology roadmap in Figure 1.4. By using field proven off-the-shelf technologies in combination with some of the emerging technologies in the high energy branch a rigless approach could be achieved. In Chapter 2 a series of conventional and field proven technologies and techniques will be presented. Chapter 3 will present two emerging high energy technologies intended to be applied for rigless P&A. A case study will be presented, using real well data, where a rigless P&A approach is proposed as an alternative to conventional P&A.

To limit the scope of this thesis some assumptions and simplifications have been made:

Simplifications:

- Case study done on Norwegian Continental Shelf wells. Plugging method to comply with NORSOK D-010 (2013a)
- All wells in case study are platform wells
    - Based on availability of well data
        - Missing data in provided data package are estimated or collected from NPD fact pages (NPD 2017) for relevant field.
    - Well intervention simplified on platform wells, no need for semi-sub rig or light well intervention vessel and associated equipment
    - All case study comparison done to jack-up rig based P&A
    - Time estimates of jack-up rig P&A operation are presented in Appendix E, G and J and are based on a limited number of operations done by a limited number of operators.
- Only subsurface activities will be thoroughly investigated
    - Deck space, accommodation, crane capacity, etc. on platforms is not main part of the study. These constrains could impose challenges on normally unmanned installations (NUI) and small wellhead platforms

Assumptions:

- Futuristic/high energy technologies presented are assumed to work as intended once commercialized.
- These techniques and technologies will be qualified for P&A operations.

Intentionally left blank

2. Technologies

A well intervention consists of a well servicing operation conducted within a completed wellbore (NORSOK 2013b). A series of more or less conventional technologies that could be interesting in a rigless TT P&A perspective will be briefly described below. This chapter is meant to give an overview with a short introduction, of what is available today. Most of these technologies have been thoroughly described by other in the past, and the interested reader is referred to the reference literature for a more detailed description. Advantages and limitations regarding the various technologies for P&A applications are tabulated in the end of every section.

2.1 Wireline

WL could be referred to as a cabling technology used to convey equipment into the well for well intervention purposes. A wireline unit with associated equipment is used to deploy a tool string to desired depth by use of gravity. A wireline package is relatively small and easy to rig up compared to other well intervention alternatives such as coiled tubing (CT) or snubbing units. One could say that wireline is a light well intervention, while CT and snubbing are medium- and heavy well intervention, respectively. A typical WL package will consist of a WL unit with cables, pressure control equipment (PCE) with pumps and panels (known as surface equipment) and downhole tools. A range of different cables could be installed into the WL unit depending on the planned operation. Wireline cables could be divided into three sub divisions; slickline, braided line and electric line, pictured in Figure 2.1. Each cable has its own applications and limitations, according to Table 2.1.

Table 2.1: List of typical wires used in a wireline operation, examples of jobs performed and advantages and limitations for the different cables (Camesa 2016).

	Typical size	Breaking strength [lbs]	Typical job	Advantages	Limitations
Mechanical wireline					
Slickline	0.125"	3800	- Drift run - Set/pull plug/DHSV – Side pocket mandrel (SPM) operations - Memory logging tool conveyance	- High tripping speed - Low cable weight - Optimal for manipulation work (jarring) - No grease head - Low cost	- Low breaking strength - Limited lifetime
Braided line	7/32"	8800	- Heavy mechanical jobs in deep wells - Fishing	- High breaking strength compared to slickline	- Lower tripping speed - Need of grease injection head
Electrical wireline					
E-line, Monoconductor	5/16"	12000	- Correlation for depth verification - Caliper log - Tractor conveyance - Perforation	- Real time data transfer. - Designed for PCE compatibility (flow tubes)	- Limited telemetry bandwidth compared to slammer cable.
E-line, Multiconductor	0.46"	19100	- Annular Cement logging - Open hole logging	- High telemetry bandwidth due to several conductors.	- Challenge to run in live high pressure wells

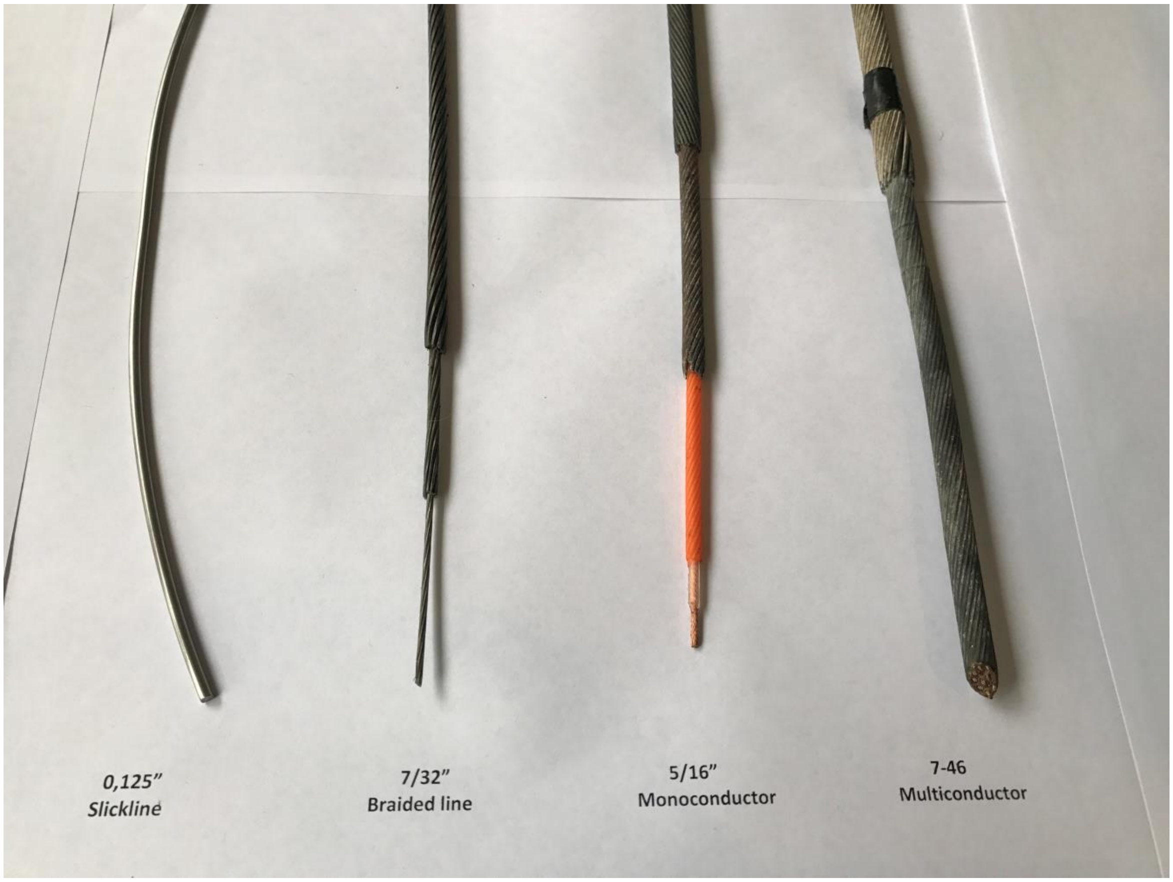


Figure 2.1: Slickline, braided line, monoconductor and multiconductor cable, respectively.

A slickline can be described as a small continuous solid strand of steel, Figure 2.1. A set of rubber packings in the stuffing box seal around the slick surface and contains the well pressure. Mechanical wires, as slickline and braided line, have a safe pull in the range of 50% to 75% of breaking strength based on service company policies. Braided- and electric lines are stranded wires. Because of the voids between the strands, the use of a rubber seal is not possible. Instead a seal is created by a grease injection head where the wire is run through several flow tubes, which have between 0.004"-0.006" larger inner diameter (ID) than the wire outer diameter (OD). By constantly pumping a high viscous fluid (wireline grease), the small clearance in combination with the high viscosity fluid will create a pressure drop over the flow tubes. The typical safe pull for e-line cables is 50% of breaking strength. In some regions of the world, all mechanical wireline operations are referred to as slickline while e-line operations are referred to as wireline. In the continuation of this thesis, wireline will be referring to both slickline and e-line operations.

With mechanical wireline, a set of jars are used in combination with weight bars (stems) to manipulate downhole tools by use of gravitational impact force. It is also possible to include jars for upward impact. By adding an accelerator to the tool string, potential energy is stored in the accelerator springs and released in combination with the jar activation. Upward impact force in excess of 200.000 lbs can be achieved with the correct cable and tool string setup, mostly for fishing applications. Conventional mechanical wireline is normally limited to a maximum of 65° well inclination due to frictional resistance between tool string and tubing wall. Tool strings have been deployed to deviations of more than 82° inclination assisted by gravity alone using low friction rollers (Al-Dhufairi et al. 2008). On a general basis extended reach and high deviation wells, in excess of 65°, require a well tractor.

A well tractor is a wireline-deployed self-propelled robotic device that will transport the tool string to the end of the wellbore if it is not possible to reach by gravity (Schwanitz and Henriques 2009). Before it was introduced in the late 90s, access to horizontal boreholes was only possible by coiled tubing or snubbing units. Well intervention in high deviation wells quickly shifted towards wireline tractor once it was introduced, Figure 2.2. In 2003, mechanical services on WL tractor were introduced including milling and stroker. The wireline stroker, a hydraulic piston, is normally used for setting and pulling plugs and can provide an axial force of up to 33,000 lbs (Schwanitz and Henriques 2009).

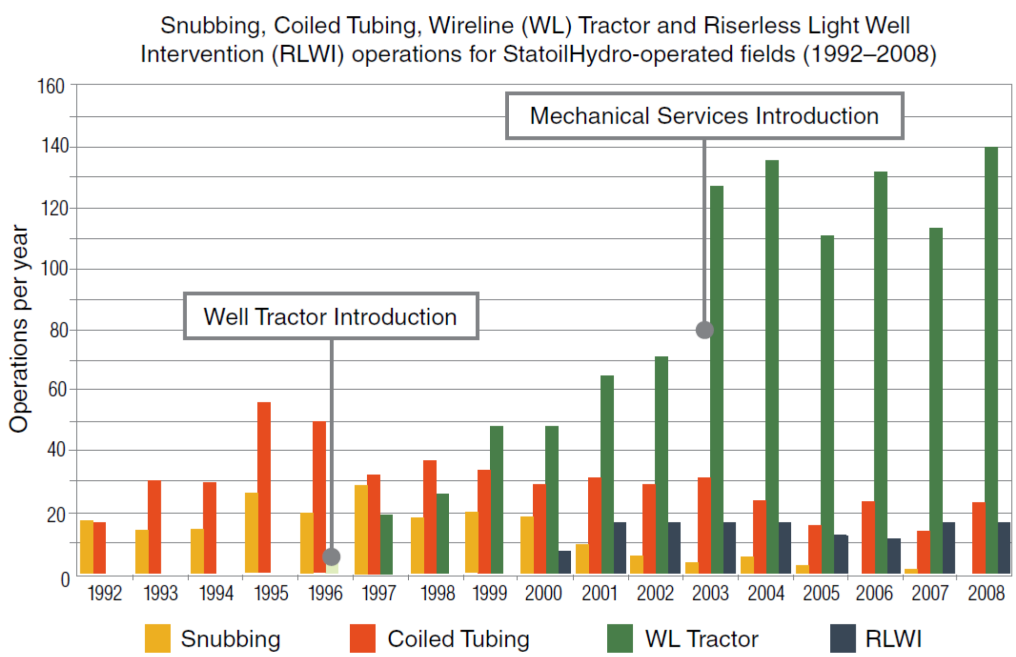
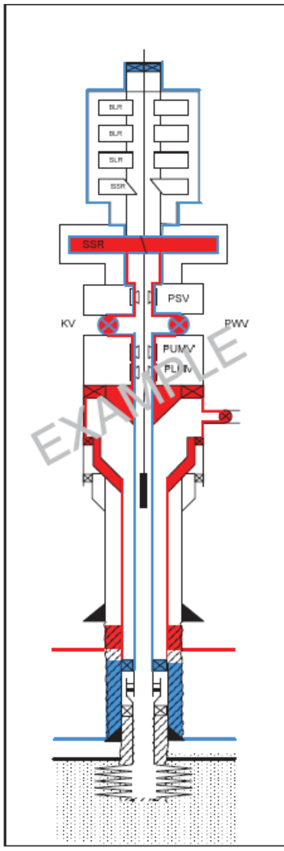


Figure 2.2: The changing composition of Statoil`s well interventions. (Schwanitz and Henriques 2009)

The high flexibility of a modular based wireline package makes it possible to rig up almost anywhere. Wireline can be rigged up stand-alone using a WL mast, through a CT tower or in a drilling derrick. The WL PCE is rigged directly on top of XT, consisting of stuffing box or grease injection head, lubricator, BOP and riser. This setup makes it possible to lubricate in and run tool strings in live pressurized wells while working in accordance with the two-barrier philosophy, illustrated in Figure 2.3. A typical setup showing WL unit and the PCE rig up with mast is pictured in Figure 2.4.



Well barrier elements	EAC table	Verification/monitoring
Primary well barrier		
In-situ formation	51	
Casing cement	22	
Casing	2	
Production Packer	7	
Completion string	25	
Tubing hanger	10	
Surface tree*	33	
Wireline shear/seal (safety head) - body	38	
Wireline lubricator	44	
Wireline BOP	37	
Wireline stuffing box / grease injection head	39	
Secondary well barrier		
Formation	51	
Casing cement	22	
Casing	2	
Wellhead	5	
Tubing Hanger	10	
Surface tree*	33	
Wireline shear/seal (safety head)	38	

*Common WBE.

Figure 2.3: Example WBS when running WL through surface XT (NORSOK D-010 2013a)

Some of the applications available by wireline will be presented in the following sections. A brief introduction to some relevant well integrity logging methods can be found in section 2.1.1. Basic applications like plug setting, depth correlation and mechanical runs like drift will not be presented.

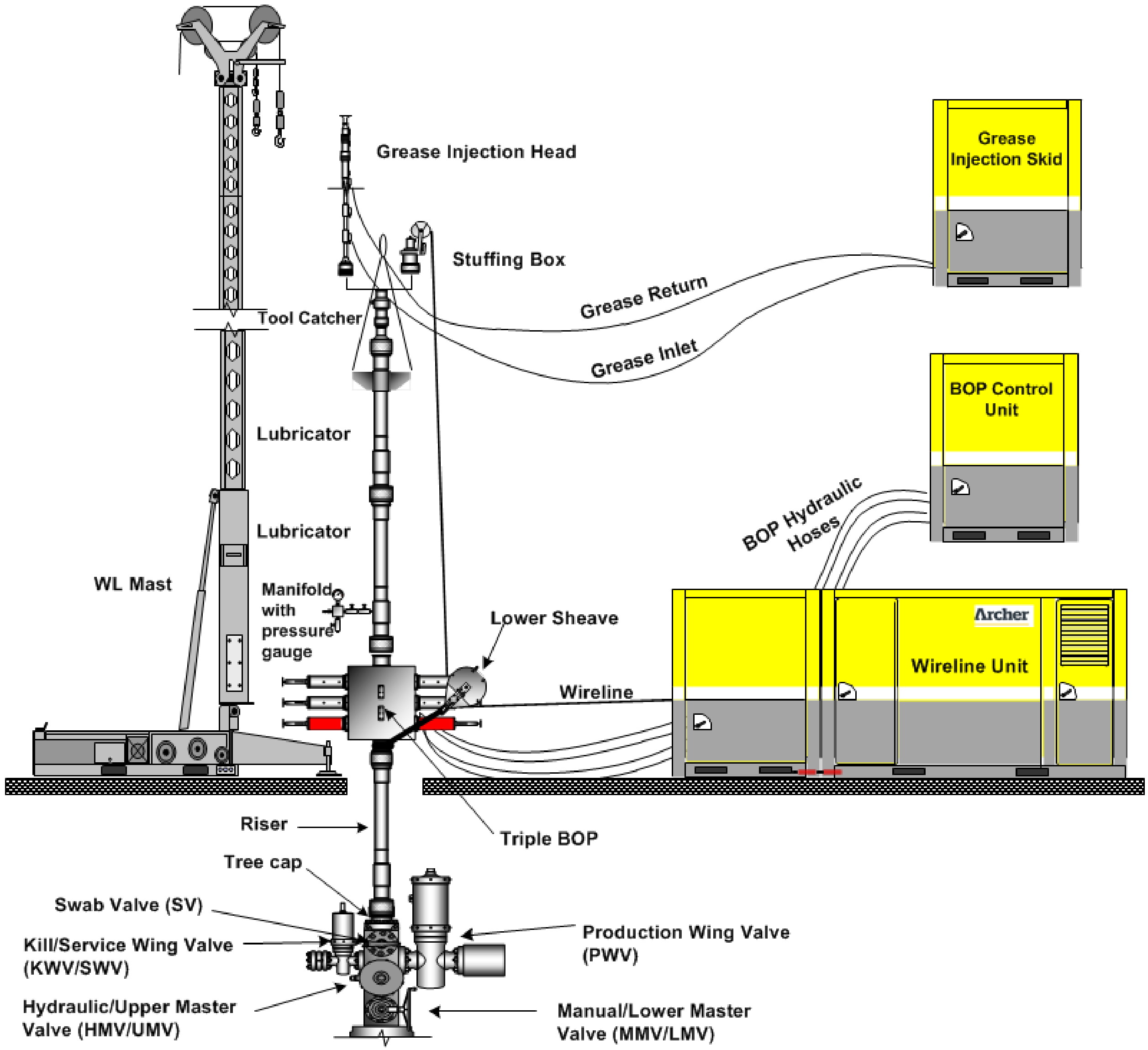


Figure 2.4: Wireline rig up illustration. Courtesy of Archer.

Table 2.2: Wireline advantages and limitations

	Advantages	Limitations
Wireline Operation	• Relatively quick to rig up. • High tripping speed. • Logging abilities through e-line. • High flexibility on rig-up. • Relatively small foot-print and low unit weights. • Operated by limited crew.	• Relatively low available pull force. • No pumping capability. • Need for tractor in highly deviated wells.

2.1.1 Well integrity logging

Jain et al. (2016) define Well integrity as: "*The ability of a well to function normally within its design safety factors and to maintain a leak free envelope such that there is no unplanned flow of fluids from or to any of the strata which the well penetrates or to external environment*". Several tools can be deployed by wireline for well logging purposes. The results from many of these logging techniques can be used in well diagnostics to verify well integrity.

2.1.1.1 Multifinger caliper log

The multifinger caliper (MFC) log can provide valuable information regarding tubular shape and wear. A series of equi-angular-spaced tungsten carbid-tipped fingers are extended until they contact the tubular inner surface (Sawaryn et al. 2015). By pulling up the tool the individual moving fingers will survey the well surface and identify pits, holes, perforations or even gross anomalies like casing deformation caused by tectonic stresses. This makes the caliper survey ideal for pipe integrity condition monitoring (Farina et al. 2015). Depending on the tubing ID to be surveyed calipers with 24, 40, 60 or 80 fingers are available as shown in Table 2.3 (Sawaryn et al. 2015). Calipers do not provide 100% coverage of the well bore as there are gaps between the fingers, as illustrated in Figure 2.5. At the expense of log resolution and circumferential spacing extended fingers can be fitted, mostly used when operations require slim tool strings for well access. Caliper data can be presented as a 2D colored pixel map over some lengths of the tubing interior or as a 3D image, Figure 2.6. (Farina et al. 2015). Although an excellent tool for inner casing measurement, it has its limitations as it is a mechanical interface log. It cannot detect metal loss in the presence of scale, nor can detect corrosion on the pipe outer surface. Combining the caliper with an ultrasonic or electromagnetic wall-thickness measurement device could provide corrosion monitoring (Sawaryn et al. 2015). MFC can be run in real-time surface readout mode on e-line or in memory mode on a mechanical wire.

Table 2.3. List of available multifinger calipers and their measurement range (Sawaryn et al. 2015).

No./Fingers		Casing Size (in.)	Accuracy (in.)	Resolution (in.)
24	Standard	1.75–4.5	0.020	0.0020
	Extended	1.75–7.0	0.020	0.0030
40	Standard	3.0–7.0	0.020	0.0015
	Extended	3.0–10.0	0.025	0.0022
60	Standard	4.5–10.0	0.025	0.0030
	Extended	5.0–14.0	0.030	0.0050
80	Standard	8.5–14.0	0.030	0.0070
	Extended	8.5–20.0	0.030	0.0140

Figure 2.5 Picture of a 24 and 40 finger multifinger caliper tool (Courtesy of Archer).

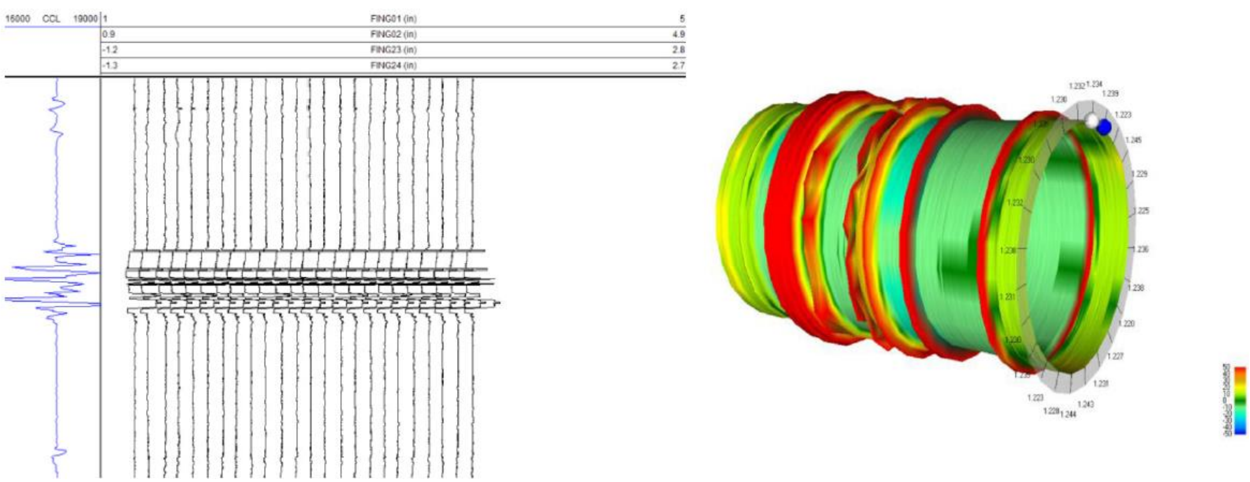


Figure 2.6 Sample of a caliper survey in a sliding side door with 3D view (Farina et al. 2015).

Table 2.4 Multifinger Caliper tool advantages and limitations

	Advantages	Limitations
Multifinger caliper tool	• Precise measurement of tubular ID. • Easy to operate and use, well known technology. • Operates in wide range of well conditions, insensitive to borehole fluid. • Can be run in combination with other tools to conceal some of its limitations. • WL tool	• 100% coverage not possible due to spread in fingers • Not able to detect metal loss in presence of scale. Scale buildup could lead to misinterpretation. • Not able to measure casing (steel) thickness. • Not able to measure outer surface corrosion.

2.1.1.2 Ultrasonic technology for leak and annular flow detection

The leak detection tool is a passive listening tool capable of mapping flowing fluids across pipe walls, but also alongside pipes, as illustrated in Figure 2.7. An ultrasonic sensor, using a piezoelectric crystal sensing device, can detect a spectrum of frequencies typically produced by a leak or flow (Johns et al. 2006). A differential pressure across a leak point will produce powerful ultrasonic acoustic energy. Ultrasonic energy can propagate through steel, water and compressed gas allowing a radial investigation range of up to 3m. Although ultrasonic energy will experience high attenuation through these media, the attenuation helps accurately detect the leak within 1-2 inches, Figure 2.8. The same concept can be applied for annular flow detection while logging through tubing. The ultrasonic spectrum for annular flow detection will not only be dependent on differential pressure, leak geometry and rate, but it is also due to bubble oscillations, bubble collapse, moderate flow, gas breaking out of solution and diameter of the flow path (Zakaria et al. 2010). The exclusive set of frequencies within the ultrasonic window can be detected by attuning the sensor to either horizontally leak detection (across pipe) or vertical annular flow detection (alongside pipe). It is important that the leaks or flows must be active at the point of logging to be detected. The tool can be run both surface readout and in memory mode (Zakaria et al. 2010). In the presence of sustained casing pressure (SCP), this technology could be vital in well diagnostics to categorize the well P&A complexity with regards to a rigless approach, or not.

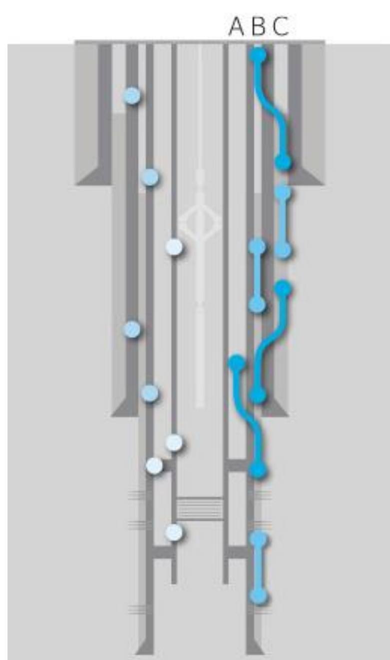


Figure 2.7: Possible leak points and flow paths detectable by the Point system (Courtesy of Archer)

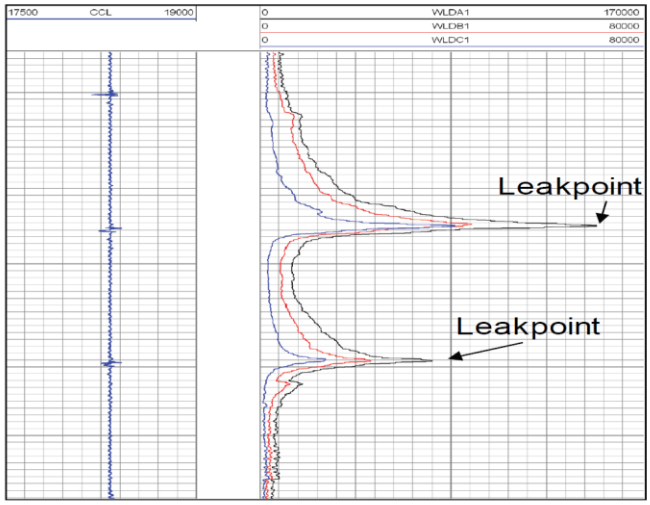


Figure 2.8: Leak detection example. Two leaks identified at tubing collars, as per CCL. Three ultrasonic frequencies are monitored showing the unique spectrum created by active leaks (Zakaria et al. 2010)

Table 2.5: Ultrasonic leak and flow detection tool advantages and limitations

	Advantages	Limitations
Point technology	• Leak and flow investigation through several tubulars. • Locates barrier leaks and flow paths downhole. • Provide clear picture of integrity status. • WL tool	• Need active leak or flow. Can usually be obtained by manipulating surface pressures. • Data interpretation, high degree of well understanding and petroleum engineering needed for flow path determination.

2.1.1.3 Electromagnetic defectoscope for corrosion detection

The electromagnetic defectoscope can be used to locate and quantify metal loss through as many as three concentric tubulars. The scanning tool records magnetization decay induced by high-power electromagnetic pulses. Different pipe diameter will produce different magnetization decay which makes it possible to distinguish and determine their individual thicknesses (Ansari et al. 2015). Three concentric pipes can be investigated for corrosion, erosion or other types of metal loss damages using the technology, but with an increasing error margin as tabulated in Table 2.6. For triple-barrier logging three sensors are utilized, Figure 2.9, generating short, medium or long electromagnetic pulses that can be detected. According to

Ansari et al. (2015) the operation of the time-domain defectoscope is based on generating square pulses equivalent to the infinite number of harmonic oscillations. During these pulses the generating coil will magnetize metal around it. After the pulse ends the magnetization starts decaying, this is captured as induced current by the receiving coils. Magnetization decay has a complex time profile and depends on the diameter, electrical conductivity, magnetic permittivity and thickness of each pipe. The logging data is processed through an algorithm which will supply a set of data for all three pipes containing; thickness data, conductivity-permittivity product indicating the metal grade and pipe decentralization profile. Corrosion detection in two nearby barriers (pipes) can be challenging as the first barrier magnetization decay is significantly higher than second or third. A defect in the first barrier will complicate the thickness determination for the second and third barrier (Ansari et al. 2015). The 1-11/16" tool can be run as a memory tool and can be used for well diagnostic purposes in advance of a P&A operation. Casing condition can be verified when exposed to sour well fluids such as H2S and CO2 throughout the casings life time.

Specification	Value
Operating temperature range	-20. . .+150 °C (−4. . .+302 °F)
Maximum pressure	100 MPa (14,500 psi)
Maximum H2S content	30%
Maximum total wall thickness	38 mm (1.5″)
Pipe diameters	51 – 381 mm (2″ – 15″)
Recommended tool speed	2 – 4 m/min (6 – 12 ft/min)
Stand-alone operating time	48 h

Figure 2.9: (Top) Electromagnetic defectoscope tool design; (Bottom) Tool specifications (Ansari et al. 2015).

Table 2.6: Smallest metal losses and corrosion degree detected by the electromagnetic defectoscope (Ansari et al. 2015).

	Minimum size of defects (metal loss)		
Laboratory test unit	**Barrier 1**	**Barrier 2**	**Barrier 3**
13 ⅜″	4″ (1.6%)	-	-
9 ⅝″ + 13 ⅜″	3″ (1.2%)	6.8″ (4.5%)	
3 ½″ + 9 ⅝″ + 13 ⅜″	0.9″ (1.2%)	5.6″ (4.3%)	8.5″ (7.1%)
3 ½″ (2 tubing strings) + 9 ⅝″ + 13 ⅜″	0.9 (1.2%)	8.4″ (9.6%)	12.7″ (15.9%)

Table 2.7: Electromagnetic defectoscopy corrosion detection tool advantages and limitations

	Advantages	Limitations
Electromagnetic defectoscopy	• Insensitive to non-magnetic scale. • Can detect metal loss (corrosion) in not only tubing, but also second and third concentric pipe (production casing and intermediate casing). • WL tool	• Slow logging speed (2-4 m/min). • Insensitive to internal or external metal loss. Will supply absolute average metal loss circumferentially. • Cannot detect holes • Defect in first tubular will complicate thickness detection of 2nd and 3rd pipe • Two nearby sized tubulars can be a challenge to distinguish on log

2.1.1.4 Cement evaluation

One of the methods stated in NORSOK D-010 (2013) for annular barrier verification is logging. Interpretation of cement evaluation logs is usually based on sonic and ultrasonic principles, each with its applications and limitations. By combining the cement bond log (CBL) and variable density log (VDL) technology with ultrasonic azimuthal logs, a more comprehensive cement evaluation can be achieved (Padilha and Araju 1997). Although initially intended for cement integrity verification, the CBL/VDL in combination with ultrasonic azimuthal logs have been applied for creeping shale annular barrier verification (Williams et al. 2009).

Cement Bond Log and Variable Density Log. CBL and VDL are acquired using sonic logging tools with a monopole transducer and a monopole receiver. The CBL and VDL receivers are placed 3 and 5 ft from the transmitter, respectively. The sonic transmitter emits a low frequency (10-20kHz) omni-directional pulse that will induce a longitudinal vibration in the pipe. The recorded data represents an average value over the whole pipe circumference. Generally the CBL logs the casing-cement bond while the VDL log the cement-formation bond. Bonded casing will lead to a high attenuation and low amplitude, while a free-pipe will omit “ringing” signals (low attenuation). The transit time, time taken for the wave to travel from transmitter to receiver, is used for quality control purposes (Williams et al. 2009).

Segmented Bond Tool (SBT) is an alternative to CBL. The SBT uses six pads to measure the cement bond in six sixty degree segments around the borehole (Tyndall 1990; Bigelow et al. 1990). These pads are in direct contact with the casing wall, and the tool will therefore be less affected by de-centralization and wellbore fluids. The SBT averages over each segment, resulting in a more accurate log compared to the CBL which averages over the whole pipe circumference. The tool can utilize in-line centralizers and log casing sizes in the range of 4-1/2" to 13-3/8" with the same setup.

Ultrasonic azimuthal bond log use a high frequency pulse echo method to excite the casing into resonance mode. A rotating transducer that operates from 200 to 700kHz provides a full coverage of the cement and casing quality, at relatively high vertical and horizontal resolution. Processing these measurements will yield the casing thickness, internal radius, inner wall smoothness and an azimuthal image of the acoustic impedance of the material behind the casing (from signal resonance decay). The acoustic impedance is then classified as that of gas, liquid or solid depending on readings (Williams et al. 2009)

Although ultrasonic azimuthal logs in general need a multi-conductor cable for high-speed telemetry, small-diameter circumferential acoustic scanning tools for mono-conductor cable have been developed (Mandal and Quintero 2010). Most of the data processing job is done downhole using a digital signal chip and efficient computational algorithms. A mono-conductor cable usually has better well control performance when running through WL PCE than a multiconductor cable. In a rigless through tubing P&A perspective the mono-cable compatible tool could be a viable choice to save time on rigging and drum changes.

Table 2.8: Cement evaluation tool advantages and limitations

	Advantages	Limitations
CBL/VDL and ultrasonic azimuthal bond log	• Enables annular barrier verification. • Technologies fulfill each other. • Well proven technology • WL tool	• Dependent on skilled personnel for log interpretations. • Should be run in combination to give a clear picture of barrier status. • Ultrasonic azimuthal tools can have challenge in high density mud. • Ultrasonic azimuthal log rotating head size vs. tubing ID in through tubing application. • Sensitive to de-centralization while logging • Conventional tools not built for through tubing applications.

2.2 Bullheading cement through tubing

The pumping operation where fluids are forced down the well by overcoming the reservoir pressure is called bullheading. Cement squeeze reservoir isolation by bullheading cement through XT and tubing could be an effective method to place a temporary primary barrier, or even establishing the primary permanent barrier. High fluid loss rate cement is preferable for reservoir squeeze jobs to ensure a proper squeeze (Nessa 2012). The lower completion will affect the applicability of cement bullheading as sand screens and gravel packed wells might not be the appropriate candidates. Volume control is crucial for a successful cementing job, and data obtained during a MFC run can be used in well volume calculations. Nessa (2012) describes the pumping sequence as following: *Spacer is pumped ahead of the cement, then fresh water, then the cement, then fresh water behind the cement. After the fresh water, displacement fluid will be pumped to displace the fluid "train" down the tubing to the target depth.* The sequence is illustrated in Figure 2.10

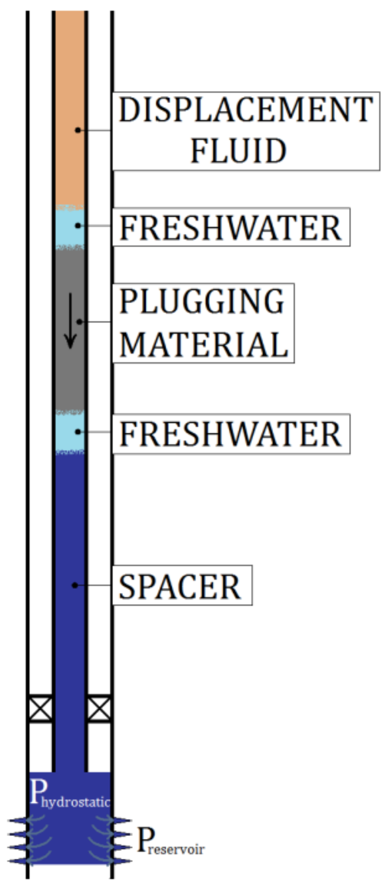


Figure 2.10: Displacement sequence in cement squeeze bullheading (Nessa 2012)

Table 2.9: Bullheading cement through X-mas tree, advantages and limitations

	Advantage	Limitations
Bullhead cement TT	• Cost effective way to plug reservoir section of a well. • Seals off reservoir perforations	• Cement settling in tubing and/or XT • Relatively high risk of cement contamination • Need well injectivity • Not optimal for screens/gravel pack

2.2.1 Improved through XT cement plug placement method

With certain well conditions it is possible to set the primary P&A barrier using a hybrid cementing technique. The method is based on some of the principles in cement bullheading (described above) used in combination with cementing wiper plugs. Some of the well conditions required are; good injectivity and a verified annular barrier element in the desired plug setting area (Olsen et al. 2017). A cement spool is connected directly on top of the XT and can be part of a well intervention rig up. The spool consists of a plug container body and is equipped with three plug release plungers and a manifold, Figure 2.11.

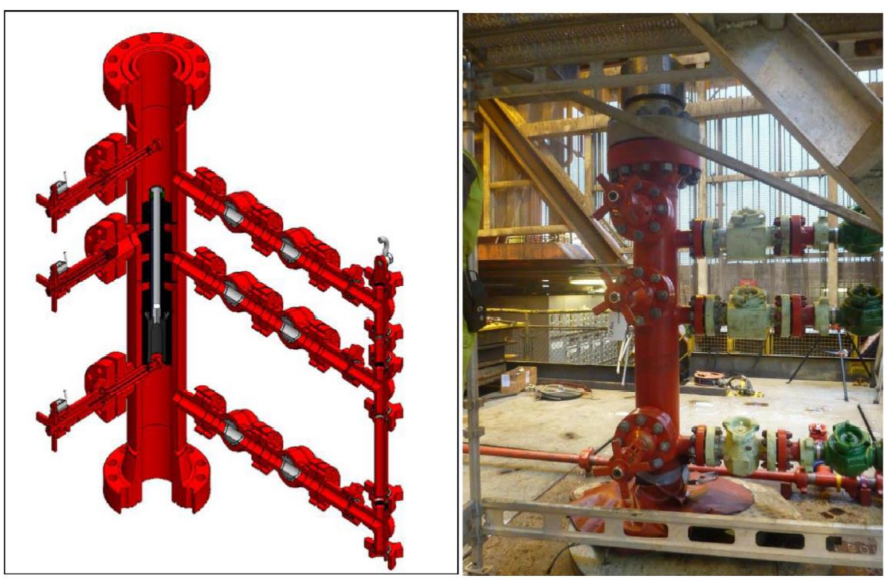
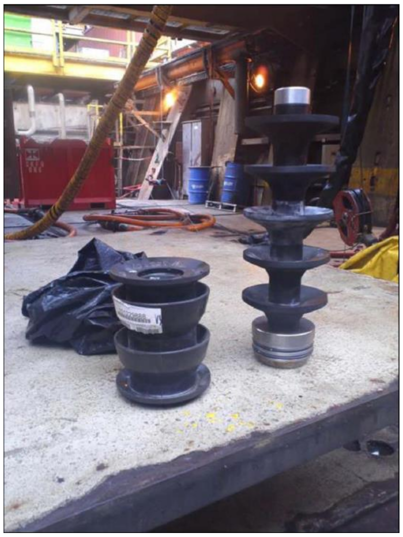


Figure 2.11: (Left) Schematic of cement spool; (right) Spool rigged up (Olsen et al. 2017)

A retrievable packer, set by wireline in the bottom of the desired plug setting area, has a seal bore landing profile in the top. This landing profile fits the lower dart, Figure 2.12, used in the concept and creates a seal acting as a base for the cement slurry above. The lower dart also has a burst disc installed that will burst if the cement plug does not hold a pressure test. The wiper darts, launched from the cement spool, are designed to separate the cement from the displacement fluid (Olsen et al. 2017). Pumping cement through XT also introduces the risk of cement settling in the XT numerous valves and cavities. To reduce this risk, a high-viscosity strongly cement-retarding post-flush pill is spotted inside the XT. The purpose of this fluid is to help remove any leftover cement slurry while also retarding any remaining cement (Olsen et al. 2017).

Operation step list summary after Olsen et al. (2017):

- Rig up cement spool and wireline equipment.
- Run the retrievable packer on wireline and set in tubing/liner.
- Install the lower dart and upper dart in cement spool.
- Mix cement slurry, release lower dart and pump slurry through manifold. Release upper dart once cement pumping complete and follow with displacement fluid.
- Monitor WHP while pumping.
- Pump retarder fluid to be spotted in XT.
- Land lower wiper plug in seal bore. The cement now sits at the desired plug area, Figure 2.12.
- WOC
- Pressure test cement plug, exceeding lower dart burst pressure to verify plug integrity.



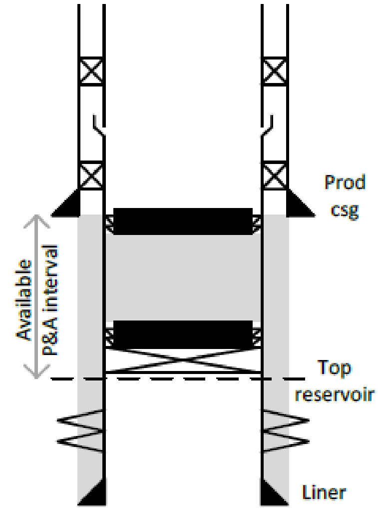


Figure 2.12: (Left) Upper and lower wiper plugs (Olsen et al. 2017); (Right) Illustration of cross-sectional barrier formed by the method (Courtesy of Statoil).

Table 2.10: Bullhead cement TT & XT using wiper plugs, advantages and limitations.

	Advantages	Limitations
Bullhead cement TT & XT using wiper plugs	• Less chance of cement contamination compared to conventional cement bullheading. • Better cement placeability	• Chance of cement settling in XT • Risk of stuck cement dart in well restrictions.

2.3 Coiled tubing

Coiled tubing (CT) can be defined as any continuously-milled tubular product manufactured in lengths that require spooling onto a take-up reel, during primary milling or manufacturing process (ICoTA 2005). The tube is usually straightened prior to entering the wellbore and is recoiled once spooled back on the reel. CT diameters range from 0.75” to 4” and steel tubes have yield strengths ranging from 55.000 to 120.000 psi. A CT unit consists of four basic elements (ICoTA 2005):

- Reel – for storing and transporting CT
- Injector head – to provide snubbing and pulling force, Figure 2.13
- Control Cabin – from which the equipment operator monitors and control the CT
- Power pack – to generate hydraulic and pneumatic power needed to operate

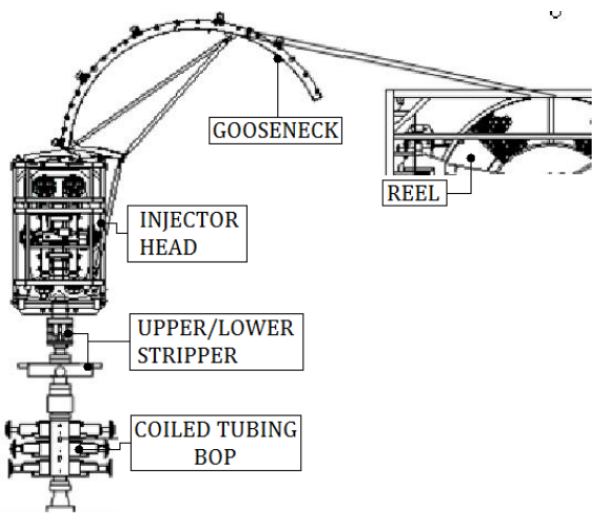


Figure 2.13: (Left) Typical coiled tubing rig up. Power pack, control cabin and safety head are not shown; (Right) Hydraulic power driven chain. Injector head consists of two chains clamping around the coil. (Nessa 2012)

CT operations on many offshore platforms are constrained by the lifting capacity of the rig cranes, as well as deck space and deck load limitations. A loaded reel is often the heaviest component (ICoTA 2005). A typical CT rig up is illustrated in Figure 2.13. Pressure control equipment (PCE) is another key component, as the majority of CT jobs are performed on live wells. A typical PCE setup from top to bottom can be; side door stripper, radial stripper, quick latch, CT BOP, risers and safety head. The strippers, containing elastomer seals, provide the primary seal around the slick tube.

Coiled tubing diameters have grown to keep pace with the strength requirements in new applications. CT up to 2-7/8” is common for routine use. The rigidity and strength of modern CT allows it to be pushed or pulled through highly deviated or horizontal wells (ICoTA 2005). This was a common application prior to introduction of WL tractor. Some of the present day major applications are well unloading, cleanouts, aziding/stimulation and fracturing. CT can also be fitted with internal electrical conductors or hydraulic conduits, which enables tool communication. Flow-activated or hydraulic tools are also common as it is possible to circulate with the CT (ICoTA 2005). Directly above the BHA a dual flapper check valve is situated. This valve will prevent well fluids from entering the CT (NORSOK 2013b). Flappers are used to allow ball drop operations as some of the flow-operated tools use balls to redirect flow.

Table 2.11: Coiled Tubing advantages and limitations

	Advantages	**Limitations**
Coiled tubing	• Pumping capabilities • Ability to circulate fluids also while running in and pulling out of hole. • High pulling force compared to WL • High deviation accessibility (limited need for tractor) • Rigless • Mobile • Relatively quick to rig up	• Fatigue issues related to the CT itself and mechanical failure. • Limited flow rate capacity compared to rig. Leading to poor solids/debris transportation: Cannot have high flowrates due to hydraulic friction. • High hydraulic friction loss due to the fluid needs to travel through whole CT length. • Production tubing wear in kick-off point on several consecutive runs. • No torque available without use of a positive displacement motor (PDM)

2.3.1 Cementing through Coiled Tubing

Cementing through coiled tubing is an operation that is conducted daily throughout the world. Typical CT cementing applications are small volume remedial jobs like (Portman 2004):

- Blocking off or squeeze perforations
- Wellbore isolation for abandonment purposes
- Cement placement through holes in completion string to produce “cement packers”
- Forming plugs for drilling sidetracks

The main goal for these operations is to place uncontaminated cement slurry at a desired point in the well. Sørgård et al. (1999) state that CT perhaps is the optimum way of setting cement plugs. It enables the cement to be pumped as the coil is pulled out of the hole, ensuring minimum contamination, as pictured in Figure 2.14.

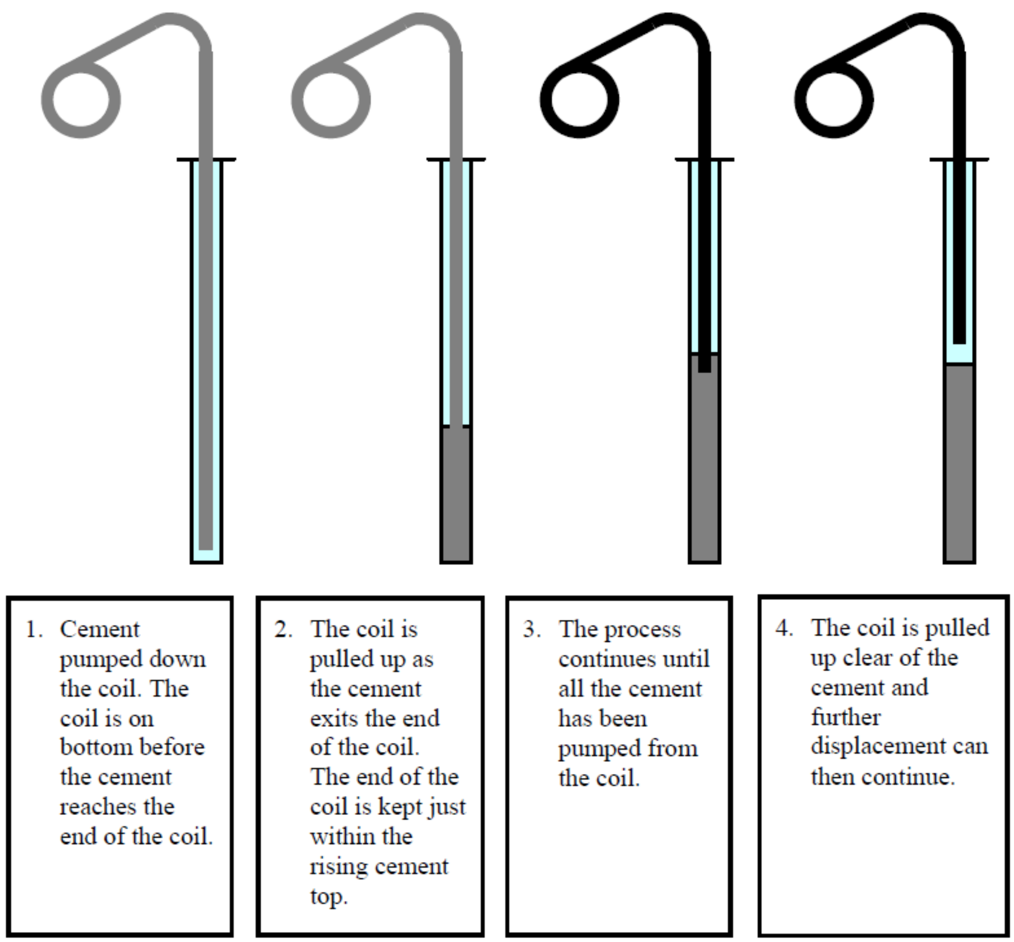


Figure 2.14: Idealized cement placement procedure (Portman 2004).

Some special considerations however have to be made when cementing through CT. First, a standard cement recipe cannot be used in CT cementing due to the limited inner diameter. A special cement slurry with longer thickening time, lower fluid loss and a lower viscosity is needed. Thickening time is a function of temperature, but could also be affected if the slurry is contaminated by brine used as spacer (Portman 2004). Secondly, a CT cement plug should be set on a base. Because cement typically has a higher density than the surrounding well fluid, it will not sit on top of a non-rigid substance. Well bottom, a cross-linked gel plug or a mechanical plug can form acceptable bases. Similar to cement bullheading through tubing (section 2.2) liquid freefall could be a challenge also in CT cementing, as listed in Table 2.12. Free-falling slurry will in most cases lead to it being contaminated. High pump rates or shearable cementing darts, as pictured in Figure 2.15, can be used as mitigating measures (Portman 2004).

Table 2.12: Typical freefall flow rates and velocities for cement and water in CT (Portman 2004).

Coiled Tubing Size (in)	Cement		Water	
	Freefall flow rate (bpm)	Freefall velocity (ft/sec)	Freefall flow rate (bpm)	Freefall velocity (ft/sec)
1¼	0.9	14	1.2	18
1½	1.5	16	2.0	21
1¾	2.2	17	3.0	23
2	3.1	19	4.2	25
2⅜	5.1	21	6.8	29
2⅞	9.0	25	12.0	33

Figure 2.15: Cement dart (Portman 2004)

In the late 1990s CT was used in a North Sea operation to create two temporary cement barriers in 10 3/4" Casing (9.66"ID). The barriers were placed to secure the well for BOP repairs. Two independent 100m+ cement plugs were placed through 2" CT, on a mechanical "umbrella" plug base. After BOP repairs, both plugs were drilled out by a rig, confirming hard cement over the intervals. Some of the key findings from this job were (Sørgård et al. 1999):

- CT is the most optimum way of setting cement plugs. Due to its ability to pull out of the hole while displacing, minimizing contamination and ensuring precise placement.
- It is possible to set gas tight cement plugs in large diameter holes (9.66") through a 2" CT even at low flow rates of 250 liters per minute (LPM) when the proper design is employed.
- Mechanical "umbrella" base used is excellent as base for cement, illustrated in Figure 2.16, and represents an improvement in cementing technology.
- Computer simulations used in cement displacement are essential for verifying the cement design.

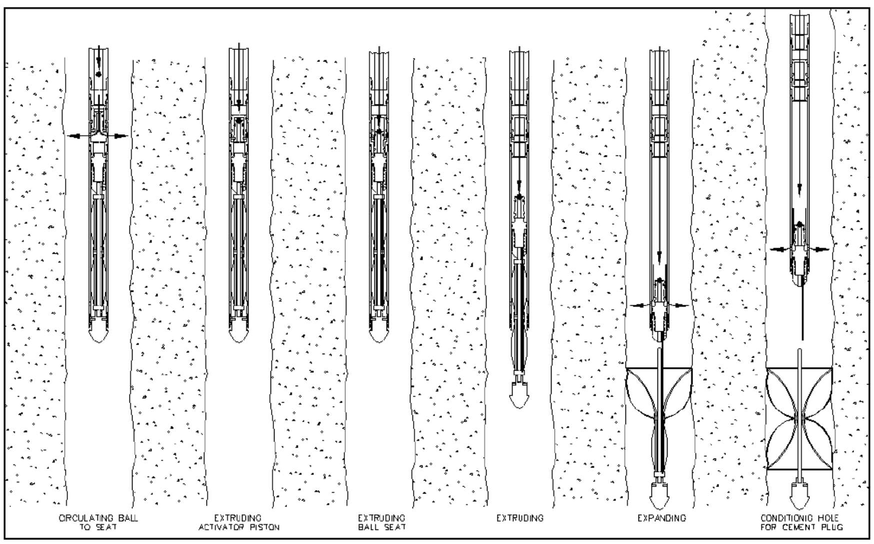


Figure 2.16: «Umbrella» Cement Base Operating Principle (Sørgård et al. 1999)

Table 2.13: Coiled Tubing cementing advantages and limitations

	Advantages	Limitations

Coiled tubing cementing	• Rigless
	• Time saving
	• Plug placement
	• Minimum contamination
		• Limited flowrate through CT
		  ○ More pumping time needed and adding of retarder to cement slurry which has a detrimental effect on cement properties
		  ○ Could lead to poor mud removal/displacement due to laminar flow in annulus
		• No possibility to dress off cement without motor
		• Tagging with minimum 10 T could be a challenge
		• Cement settling inside CT

2.3.2 Coiled tubing wellbore cleanout

Through tubing cleanout using fluids and tools conveyed by CT is considered standard industry practice. Different cleanout systems have been developed over the years employing several different techniques and approaches. Both forward and reverse circulation is used throughout the world for well cleanup. Stationary circulation, wiper trip, reverse circulation, sand vacuuming and various bailers are some of the methods available. This thesis will focus on wiper trip hole cleaning, as this technology has well proven large wellbore cleaning ability. It is therefore most relevant for NCS P&A applications. In conventional sand cleanout operations, severe loss to the perforations can be experienced in depleted reservoirs. This leads to low annulus velocity and related poor solids transportation (Li et al. 2008). In a P&A operation, loss to the reservoir would not be a problem as it could be isolated prior to the cleanout operation. The wiper trip method, illustrated in figure 2.17, is based on a specialized tool used in combination with a solid-transportation simulation for CT. The tool offers the option of downward facing high energy jetting nozzles or a positive displacement motor (PDM) to ensure sufficient energy for hard solids penetration (Li et al. 2008). Once the solids have been penetrated, the tool allows the cleanout fluid to be directed upwards in some low energy nozzles. This also stops the fluid flow to the PDM and jetting nozzles. Pumping through the upward facing nozzles, while carefully pulling out of hole, the solids will be “swept” out with almost 100% efficiency (Li et al. 2008). The constant upward facing nozzle flow will agitate the solids and entrain the particulates in suspension for transportation out of hole. Solids are always located directly above the BHA, and the correct wiper speed is extremely important. Common circulation fluids for sand cleanout is formation water, sea water, brine, diesel or crude oil, which all can be mixed with nitrogen to lower the hydrostatic head if necessary (due to low reservoir pressure and high fluid loss rate). Fluids with improved solids suspension capabilities, such as biopolymers and foam, are available but also have their advantages and disadvantages. One of the biopolymer disadvantages is that once a cutting bed is created on low side, it is very hard to agitate as the coiled tubing does not rotate. This makes the particles stick to each other.

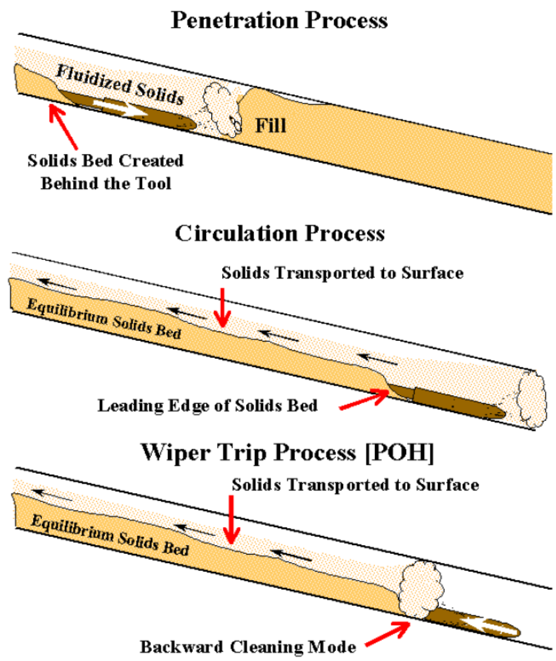


Figure 2.17: Typical stages of a wiper trip clean-out method (Li et al. 2008)

Li et al. (2008) presents a relevant case study from the Norwegian sector of the North Sea. A 1350m section of a wellbore, mostly 7" but also included a 341m 9-5/8" section, needed to be cleaned out. The reservoir was isolated by a kill pill preventing fluid losses, as the reservoir pressure was relatively low. The 9-5/8" section was successfully cleaned out using the wiper trip method and a tripping speed of 2-3 m/min. 2-3/8" CT and a sea water based cleanout fluid containing hydraulic friction reducer were used to obtain highest possible pump rates. 8-10 bottoms-up was pumped before any solids were confirmed at surface. This confirmed that circulation rates up to 850 LPM and CT stationary on bottom is not enough for solids removal. The solids must be suspended, and held suspended above BHA while pulling out. A total of 6000-8000kg of solids was recovered in this operation using the wiper method (Li et al. 2008)

Table 2.14: Coiled Tubing hole cleaning advantages and limitations

	Advantages	**Limitations**
Coiled tubing Hole cleaning	• Rigless • Proven for sand clean out in large wellbore ID • No need for mud	• Stationary circulation for hole cleaning is challenging • Limited flowrate • Slow progress on wiper trip method in large ID clean out

2.3.3 Abrasive cutter deployed via Coiled Tubing

The pumping capability of coiled tubing make it possible to use abrasive cutters. An abrasive cutter use cutting particles (such as sand or glass beads) mixed with water. This mixture is pumped through a rotating cutting head with nozzles, and the abrasion erodes the steel. A key component in the system is the *sealed bearing pack positive displacement motor (PDM)* (Loving et al. 2005). The PDM drives the rotating cutting head with its nozzles. A successful abrasive cut relies on proper nozzle selection and is determined by CT flowrate and hydraulic calculations. During testing a 2.875” 8.7 ppf P-110 tubing was cut in 4 minutes using a pump rate of 4 bpm (635 LPM). Successful multiple simultaneous casing cuts on 13-3/8” and 9-5/8” have been performed in P&A applications (Loving et al. 2005). In addition abrasive perforations, as illustrated in Figure 2.18, are possible using the same technology by removing the rotating head.

Figure 2.18: CT abrasive perforation head after completed job (Loving et al. 2005)

Table 2.15: Coiled Tubing abrasive cutter advantages and limitations

	Advantages	Limitations
Coiled tubing abrasive cutter	• No explosives • Cuts through several casings in same cut	• Abrasive cutting particles needed • Large surface spread required for abrasive particles • Tool washout • Time to clean out abrasives from well

2.4 Section milling

Section milling will not form part of the rigless approach to P&A, but it is an important technique used in conventional P&A and is addressed here for completeness. In addition, one of the emerging technologies presented in Chapter 3 is a new approach to section milling, a brief introduction is therefore provided below.

In the absence of an annular barrier, the conventional approach to create a cross-sectional barrier is to remove the casing by section milling, clean the open hole section, under-ream to expose virgin formation and set a balanced cement plug (Ferg et al. 2011). A mill is deployed to the desired depth. The section mill tool features several "knives" on pivots which swing out of the tool once a cone is actuated by hydraulics. Considerable force is exerted from the cone, acting on the knives to mill through the casing. Once milled through the casing wall and fully extended the knives are locked in position. Weight is applied from the surface to mill the desired interval of casing, exposing an open hole (Stowe and Ponder 2011). Downhole metal cutting is a challenge due to the high level of axial, lateral and torsional vibrations exhibited by a drill string. A typical P&A interval of 50m needs an average of 1.55 trips to complete using tungsten carbid knives, Figure 2.19 (Stowe and Ponder 2011).

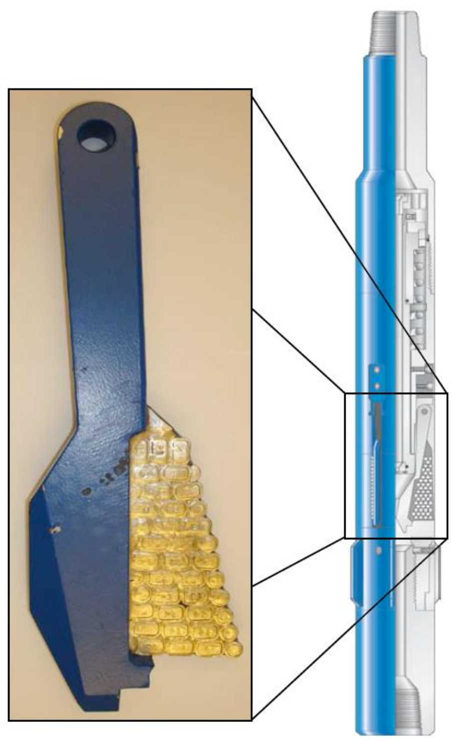


Figure 2.19: (Left) Cutter/"knife"; (Right) section mill tool (Stowe and Ponder 2011)

Section milling tools with active stabilizers to reduce vibrations have been introduced, reducing the total number of trips required (Ghegadmal and Ponder 2016). Fluids used with section milling need sufficient density to keep the open hole interval stable and a suitable viscosity to suspend and transport swarf (metal cuttings produced from mill) and debris. The equivalent circulating density (ECD) exerted by this fluid could lead to the exposed open hole section exceeding its fracture pressure (Ferg et al. 2011).

Table 2.16: Section milling advantages and limitations

	Advantages	Limitations
Section milling	• Will create a full radial rock-to-rock barrier plug • Continuous plug with no metal as part of Well Barrier Envelope	• Swarf handling downhole. • Swarf handling at surface. • Well control due to swarf handling. (BOP) • High ECD due to density and high viscosity fluid. • Time consuming.

2.5 Perforate, Wash and Cement

The Perforate, Wash and Cement (PWC) method was developed for wellbore barrier placement in un-cemented casing intervals, as an alternative to traditional section milling (Delabroy et al. 2017). The method is used by major operators on the NCS in conventional P&A. It could also be a viable rigless application using CT or snubbing unit in the future. The rigless PWC approach is not part of this thesis but the conventional approach will be briefly discussed below.

A bottom hole assembly (BHA) consists of perforation guns, a washing tool and a cement stinger. The concept allows placement of a cross-sectional barrier in an un-cemented casing in one trip. 50 m of drill pipe conveyed perforating guns, with 12 shots per foot (SPF) in 135/45-degree phasing, Figure 2.20, are placed at the desired intervals and drop when firing (Ferg et al. 2011). Once the guns are dropped, circulation and conditioning of the mud to account for the actual pore pressure can be done. After the desired fluid properties have been obtained a ball drop is conducted to re-direct the fluid flow out through two cups. These cups will direct the fluid through the perforations for a washing operation in a top-down direction (Ferg et al. 2011). After the washing sequence, a cement spacer is pumped before the washing assembly is disconnected by a ball drop, to function as a base for cement. Cement is pumped while rotating the string to agitate the cement for better displacement behind perforations. The BHA remains in hole during WOC for washing down and testing the plug (Ferg et al. 2011). A further development of the method is described by Arsalan et al. (2016) for improved washing and cementing using jetting tool, illustrated in Figure 2.21a and 2.21b. As PWC is not described in NORSOK D-010 (2013a), a qualification matrix has been developed and described by Delabroy et al. (2017).

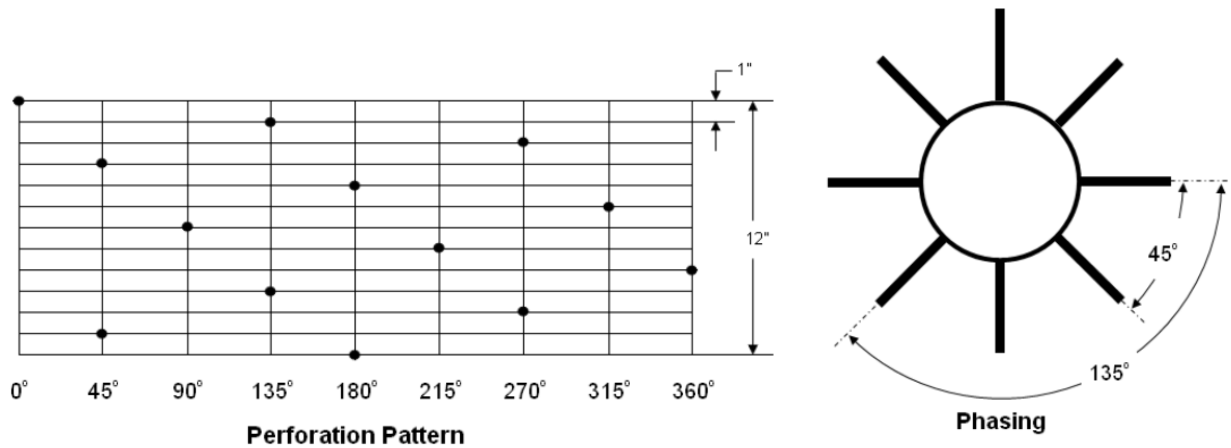


Figure 2.20: Perforation pattern and phasing (Ferg et al. 2011)

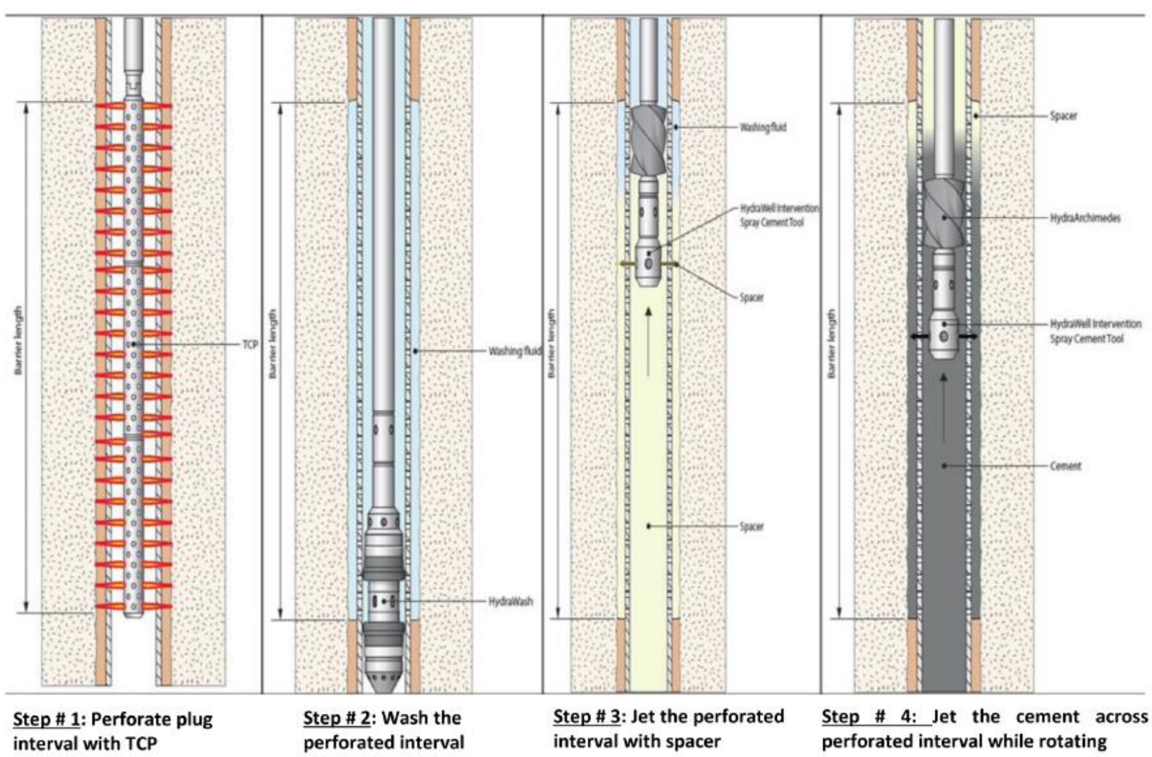


Figure 2.21(a): PWC using jet system and two trip approach. Step 1-4 (Arslan et al. 2016)

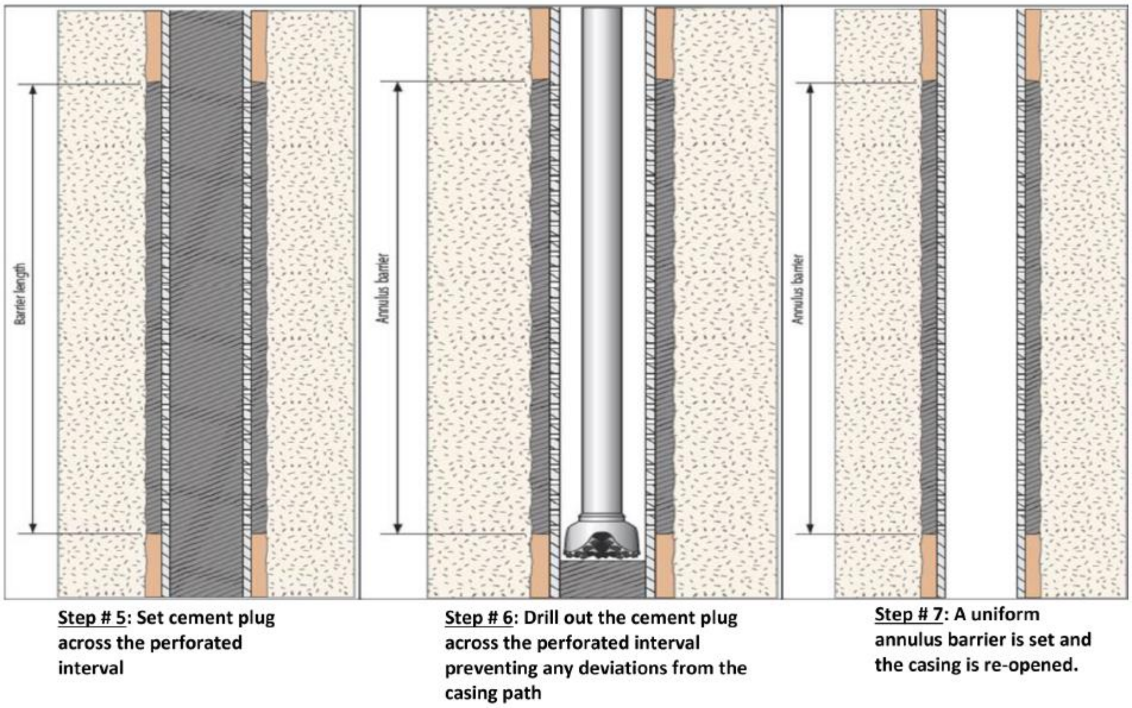


Figure 2.21(b): PWC using jet system and two trip approach. Step 5-7 (Arslan et al. 2016)

Table 2.17: Perforate, Wash and Cement advantages and limitations

	Advantages	**Limitations**
Perforate, Wash and Cement method	• Un-cemented casing annuli can be effectively isolated. • No swarf handling both downhole and on surface. • Well control enhanced. BHA at depth during operation and no swarf in BOP. • Significant time saving compared to section milling.	• Relatively new technology – needs implementation to regulations/guidelines/standards • Long cement plug placement in one run (in a plug verification perspective) • Removal of existing mud or settled barite behind csg. • Plug qualification method is not available in current NORSOK D-010 rev 4 (2013a)

Intentionally left blank

3. Emerging P&A technologies

In sections 3.1 and 3.2, two non-commercialized emerging P&A technologies will be presented. The aim is to perform a case study using these technologies in a rigless P&A approach to platform well plugging. The case study is presented in chapter 4.

3.1 Electric plasma miller

3.1.1 Electric plasma

Plasma is defined as: *"A highly ionized gas in which the number of free electrons is approximately equal to the number of positive ions. Sometimes described as the fourth state of matter, … "* (Oxford U. 2009)

The concept was initially meant as an innovative non-contact tool for accessing sources of geothermal energy (Kocis et al. 2015). A set of prototypes was built and the oil & gas industry showed interest. A joint industry project (JIP) was initiated in 2013 including operating companies and service providers to further develop the technology. The original scope of the JIP project was to develop a plasma based drilling solution, but during the years several other possible applications have emerged including steel and cement milling being one of the main focus areas today (Kocis et al. 2015).

Electric plasma brings some advances in comparison to conventional plasma torch and other thermal non-contact approaches (Kosic et al. 2015):

- The electric arc, with temperatures of more than 10,000 Kelvin (K), heats the surface of the disintegrated material directly with minimum heating of the intermediate gas (which reduces the effectiveness of heat transfer in conventional plasma torches).
- The heat flow is area-wide, shown in Figure 3.1, and relatively homogeneous by applying a long arc on the whole surface for a high-intensity disintegration process.
- The rotating spiral arc has a "built-in" centrifugal pump function for disintegrated material removal, in addition to the thermal influence.
- Direct electric arc plasma technology allows use of an electrohydraulic phenomenon that generates shock- and pressure waves for destruction and transportation of disintegrated materials away from the BHA. Conventional plasma torch does not have this ability.
- High intensity short current pulses generate pressure waves. These pulses are accumulated allowing an increase in instantaneous pulse disintegration effect with power pulses in megawatt (MW) scale.

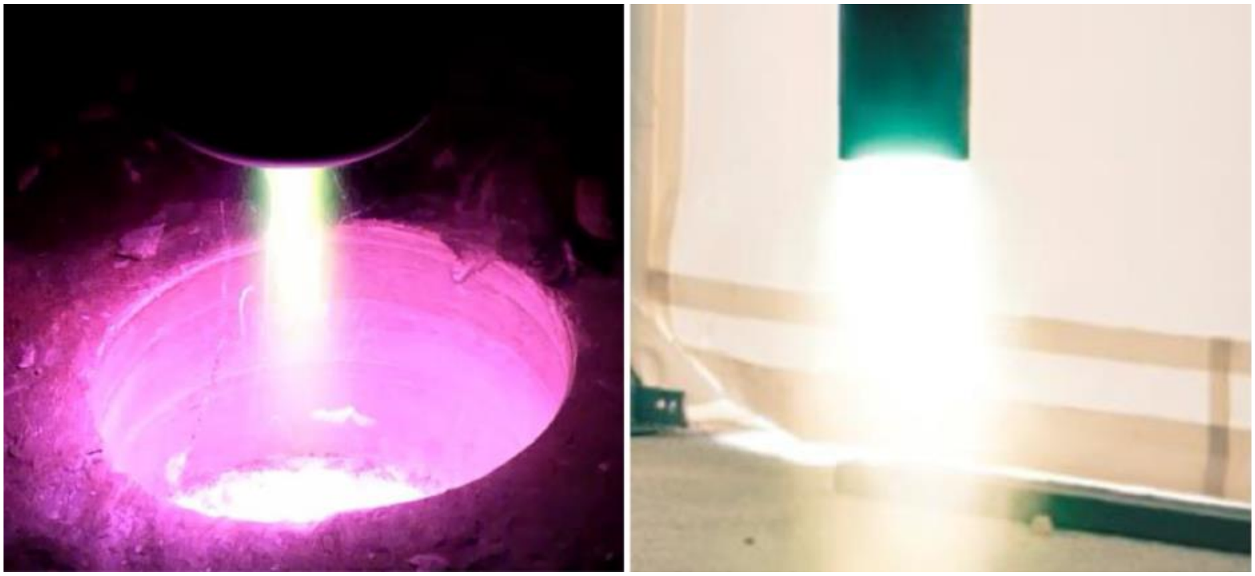


Figure 3.1: Difference in plasma shape, (Left) narrow conventional plasma flow – (Right) Electric arc area-wide plasma flow (Kocis et al. 2015).

Electric plasma for hard rock drilling is based on thermal rock disintegration in a non-contact process (Kocis et al. 2015). The thermal characteristics such as; boiling point, melting point and thermal conductivity of the rock will determine rate of penetration (ROP) in a given rock. Spallation, melting and evaporation are modes of disintegration and distinguishable by the plasma temperature. As melted and evaporated rock elements produce relatively high intensity radiation a real-time analysis through a spectroscope could be possible using the technology as shown in Figure 3.2.

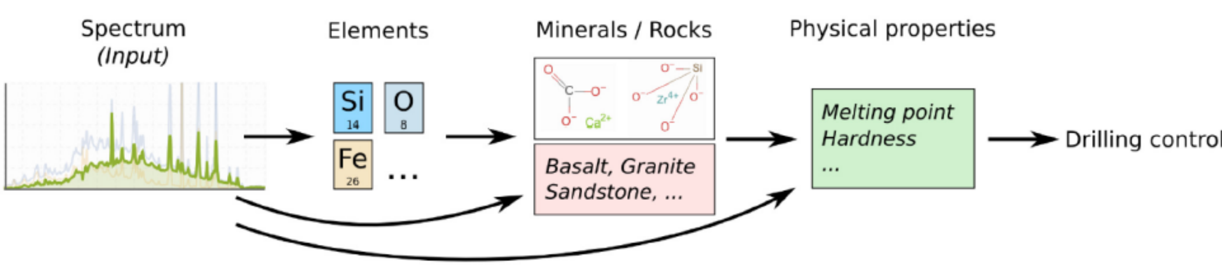


Figure 3.2: Spectra analysis hierarchy (Kocis et al. 2015).

Electric plasma for casing milling uses a similar approach (Kocis et al. 2015). Commercial available oxy-fuel flame cutters or high temperature plasma jets, using argon/hydrogen/oxygen plasma, could be used for casing milling. However these technologies have a narrow cross-sectional interaction area with the target metal surface, which is optimal for simple metal plate cutting. This does however impose a time and technical limitation for total metal removal. By combining a high temperature large cross-section plasma torch and a rotating electric arc a new generation of plasma generator was created, proving to be an effective tool for casing milling (Kocis et al. 2015). The technology is based on a hybridized plasmachemical and thermochemical process resulting in a fast metal degradation and removal in a water steam environment. The processes involved in steel removal are (Kocis et al. 2015):

- Oxidation
- Melting
- Evaporation

A necessary note is that oxidation is active in both melting and evaporation process for steel temperatures up to 3500K. Several studies on water steam and temperature in steel removal conclude that temperature and heat transfer play a key role in steel removal rate (Kocis et al. 2015). The proportional contribution of thermochemical and thermophysical processes resulting in steel removal effect therefore varies with changing temperature and brings the following basic features (Kocis et al. 2015):

- Oxidative part of steel structural degradation is an exothermic process leading it to supply additional energy for all steel removal sub-processes.
- Steel oxidation and evaporation rate rises with increasing plasma temperature, power density through the plasma-steel interface and plasma enthalpy.
- Oxidation and evaporation rate of steel is most efficient in water steam and air/steam mixtures (with regards to energy consumption).
- At a narrow temperature window, 3330-3660K, enthalpy liberated from the oxidative process is raised by the factor of three. I.e. three times more energy is supplied into the steel removal process without the increase of external power to the plasma generator. This window should be available for all alloys of steel since at these temperatures all compounds are in gaseous phase.
- Steel surface temperature in excess of 3660K will lead to a total dissociation and evaporation occurrence. Metal etching effect is the result from plasma particles (in form of active ionic atoms) impact to the steel surface. It is important not to forget that oxidation is still active during melting and evaporation process.

Cuttings from experiments done on carbon steel show a microstructure with clear dominant presence of iron(II) oxide. Analysis showed structural heterogeneity between oxidized and metallic layers in cuttings. The difference in thermal expansion coefficient of metal/oxide systems at the boarder of a metallic and oxide layer results in a hydrodynamic destruction of such weak multilayers, as illustrated in Figure 3.3a-b (Gajdos et al. 2015a). In the case of alloy steel, thermal expansion properties of steel/oxide differ even more, because of the higher grade of chemical heterogeneity in the microstructure.

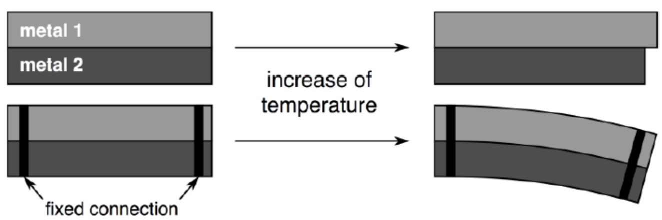


Figure 3.3a: Illustration of different volumetric thermal expansion of multilayered structures in a microstructural perspective (Al Furati 2016).

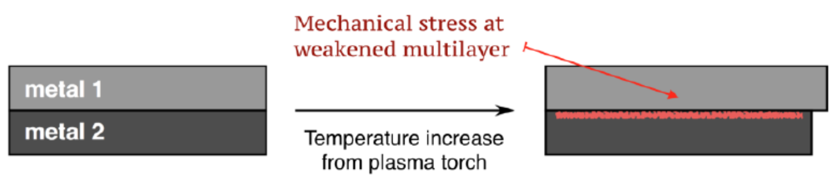


Figure 3.3b: Mechanical stress due to temperature increase on a microstructural level, leading to disintegration of metal, caused by difference in thermal expansion coefficient between layers (Al Furati 2016).

Metal disintegration has a high-energy consumption. During experiments at different boundary conditions metal cutting effectiveness could be categorized by one parameter, ε (Gajdos et al. 2015a). ε describes the energy needed to remove a mass of steel under certain conditions. The parameter describes the liberated energy coming from an exothermic iron oxidation process and real electric energy input to the plasma generator, where ε always is lower than consumed electric energy.

$$\varepsilon = \frac{U \cdot I \cdot t}{m} \tag{3.1}$$

where:

ε [J/kg] : net energy requirement per unit mass of steel removed

U·I [W] : electrical power to plasma generator ([V]·[A] = [W])

t [s] : time of process

m [kg] : mass of removed steel

A steel removal rate (SRR) could be estimated based on casing conditions in water environment at low temperatures. Gajdos et al. (2015a) estimates a SRR of 210 kg/h leading to a cutting rate of 2.0 – 4.5 m/h for a 9-5/8” casing section. This estimate is based on an ε of 3 MJ/kg, a power output of 250kW and plasma efficient of 70%. Expression 3.2 is the same as 3.1 solved for mass over time [kg/s], including plasma torch efficiency and converted to hours.

$$SRR = \frac{U \cdot I \cdot 3.6 \cdot 10^3}{\varepsilon} h \tag{3.2}$$

where:

SRR [kg/h] : steel removal rate

U·I [W] : electrical power to plasma generator ([V]·[A] = [W])

$3.6 \cdot 10^3$: seconds per hour

ε [J/kg] : net energy requirement per unit mass of steel removed

h : plasma torch efficiency (0→1)

Estimating a constant power output of 100kW during downhole operations, based on umbilical max constant power transfer of 150kW (Figure 3.5), the effective SRR will be 84 kg/h.

Cutting rate for a typical NCS 5-1/2” 20ppf (29.76 kg/m) tubing, using the estimated SRR input of 84 kg/h, will be 2.82 m/h.

$$Cutting\ rate = \frac{SRR\left[\frac{kg}{h}\right]}{tubing\ weight\left[\frac{kg}{m}\right]} = \frac{84}{29.76} = 2.82\ \left[\frac{m}{h}\right] \tag{3.3}$$

3.1.2 Plasma miller for P&A

A plasma miller could be a viable rigless alternative to pulling tubing and section milling once commercialized. The plasma miller is planned to be deployed using a CT unit as this will provide the ability for through XT and tubing operations. Gajdos et al. (2015a) presents a P&A case study where a plasma miller is proposed as an alternative solution to section milling. The conventional approach is similar to that presented in section 1.2. The alternative approach to cross-sectional barrier placement is presented below:

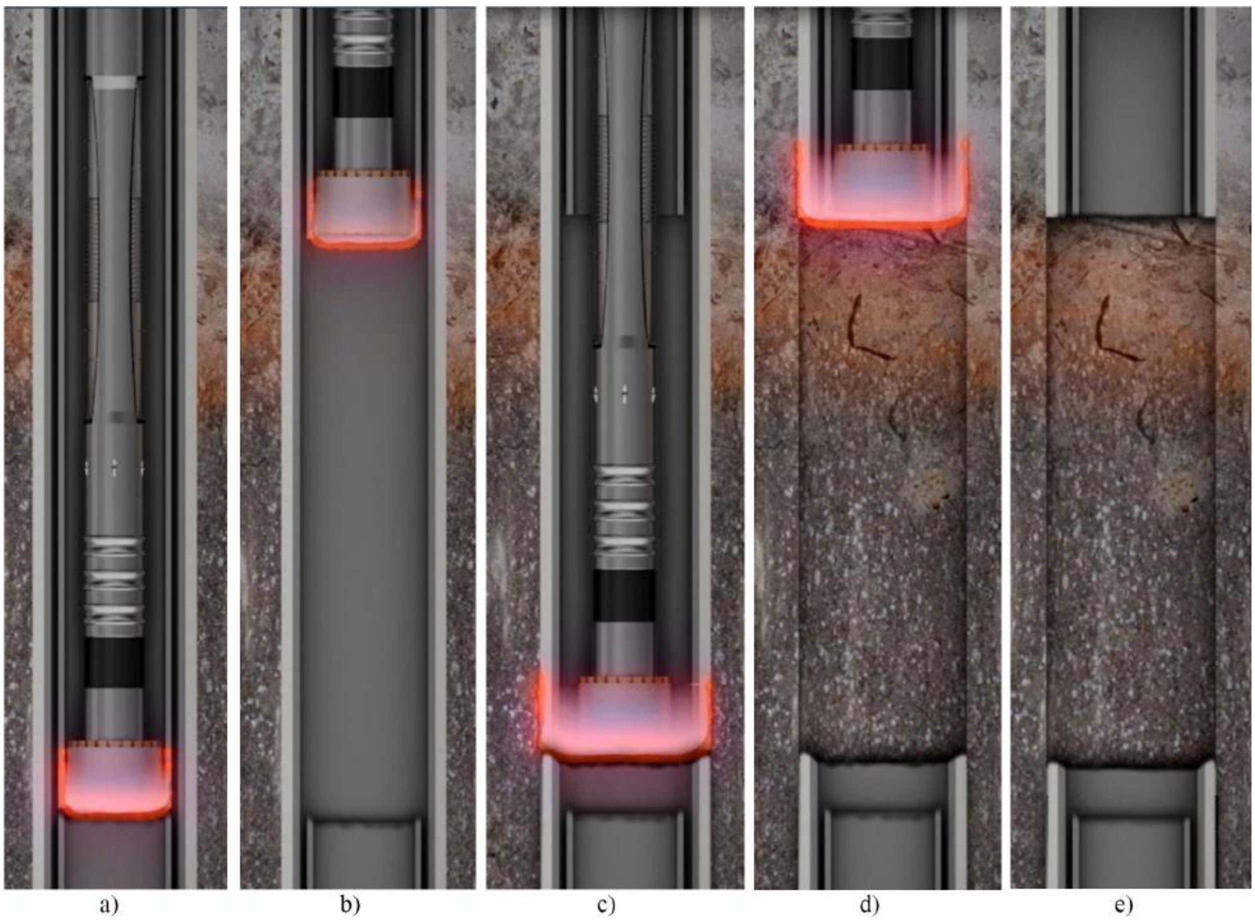


Figure 3.4: Alternative solution to section milling by use of plasma miller conveyed by CT (Gajdos et al. 2015a)

- Rig-up on well and set bridge plug as base for reservoir cement plug (allow for milling debris sump)
- RIH with plasma miller to mill desired window through tubing, Figure 3.4 a & b
- Run in on same trip to mill same interval of casing and cement, Figure 3.4 c & d
- Set reservoir barrier

- Set mechanical base for intermediate cement plug above permeable zone with potential
- RIH with plasma miller to mill desired window through tubing, casing and cement, Figure 3.4
- Set intermediate cement barrier
- Set environmental barrier
- Sever and retrieve tubulars and wellhead from below mudline.

If casing and cement have integrity, it would be possible to log (and verify) the casing cement, and not remove it. The verified annular barrier could form part of the cross-sectional barrier. Keeping the cement and casing in place would also simplify the operation. When removing casing and cement the formation is exposed. Several considerations have to be addressed while working with an open hole section. Hole-stability and pore pressure are some of the concerns, and dealt with through the use of drilling mud. By leaving the casing in place, use of mud and exposure to formation could be avoided.

Power supply is one of the main challenges related to the downhole operation of the plasma miller (Gajdos et al. 2016). A specialized umbilical, illustrated in Figure 3.5, is planned to supply the needed power in addition to fluids and data transferability. The umbilical is made for deployment using a CT unit, and could be compared with electrical submersible pump (ESP) installation using CT. In ESP installation an electric power umbilical lowered with CT enables fluid circulation and weight support of the power cable and ESP through an anchor to the coiled tubing (Gajdos et al. 2016). The choice of a coiled tubing approach also enables operations on live wells, TT and XT. A possible challenge using a CT umbilical will be weight limitations on cranes and deck. These limitations will not be part of the viability consideration in this thesis.

Parameter	Value
Cable length	up to 12 000 ft
Transferred Power	150kW (up to 500 kW)
Voltage	1kV (up to 4kV)
Current	up to 500A
Cooling water for PLASMABIT Milling	60 litres per min
Optical fibre for spectral information transport	250nm - 1500nm
Data line	4 wire data line

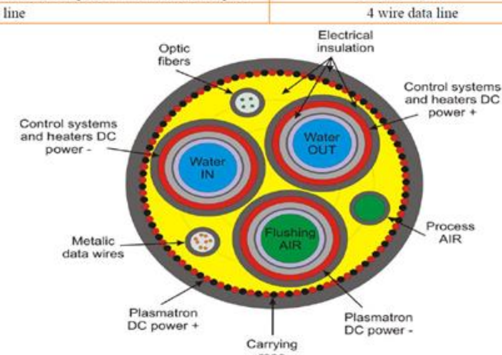


Figure 3.5: Umbilical for testing of plasma miller (Courtesy of GA Drilling)

Disintegration of eccentric tubing and the possible damage to the casing caused by heat during milling was researched in experiments (Kristofic et al. 2016). Two steel plates, electrically connected to the same potential, were set up with 1mm, 5mm and 10 mm space between them. This setup simulated different degrees of pipe eccentricity. Only a small amount of melting and low temperature oxidation was observed on the 1mm specimen while the 5mm and 10mm specimens had no melting and only minor oxidation on surface (Kristofic et al. 2016). This was according to expectations as the milling process using the electric arc is restricted to the active electrodes.

Cuttings size and shape produced by the plasma miller is a major benefit compared to section milling. Where section milling produces swarf, the plasma miller produces small particles with a majority of them smaller than 5mm. Cuttings from several experiments have been analyzed. Different milling environments produce different cutting distributions. Cuttings from tests done in fresh water, brine and in a high pressure brine environment are shown in Figure 3.6 a-c, respectively. The cuttings have a shape that will render possible collection in the sump/rat hole created above the cement base plug. Alternatively, they could be collected and brought to surface.

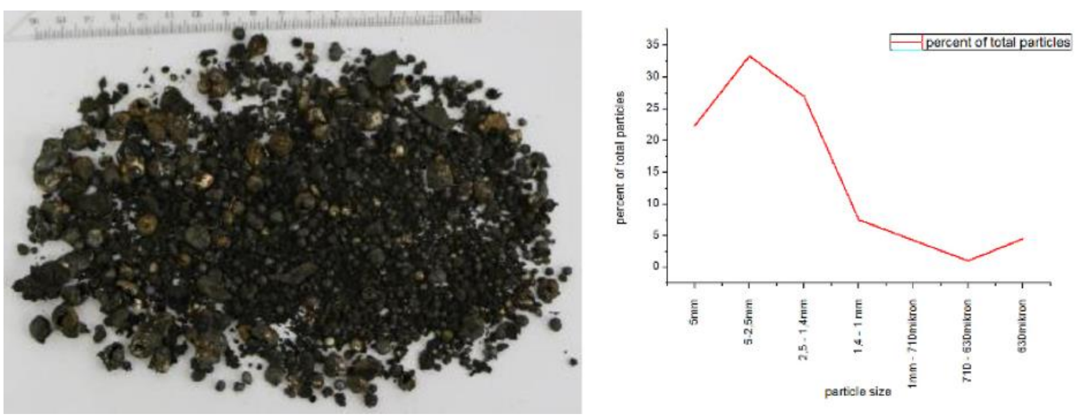


Figure 3.6a: (Left) Cuttings generated during plasma milling in water environment; (Right) Cuttings size distribution (Gajdos et al. 2015a).

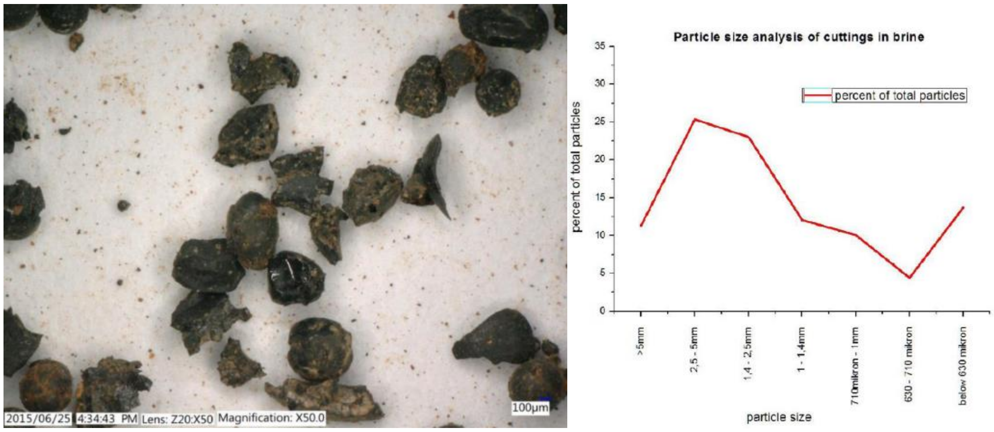


Figure 3.6b: (Left) Typical shape of cuttings in 0.7-1.0mm range (image from optical microscope); (Right) Cuttings distribution in brine environment (Gajdos et al. 2015b).

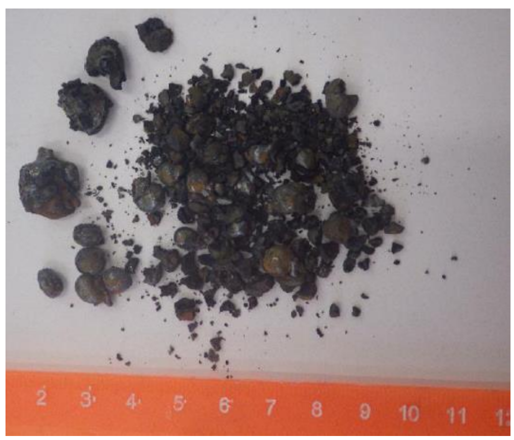


Figure 3.6c: Samples of cuttings after test done in high pressure (20MPa) brine environment. The irregularl shape large aggregates were found to be several cuttings clustered together (Kristofic et al 2016).

3.1.3 Research and development of electric plasma miller

The findings and progress during research and development (R&D) have been presented and published in papers throughout the period. A brief overview of the R&D and technology verification in different environments is presented below. The interested reader is referred to references.

- Kocis et al. (2015) presents tubular milling in air at atmospheric pressure, Figure 3.7.

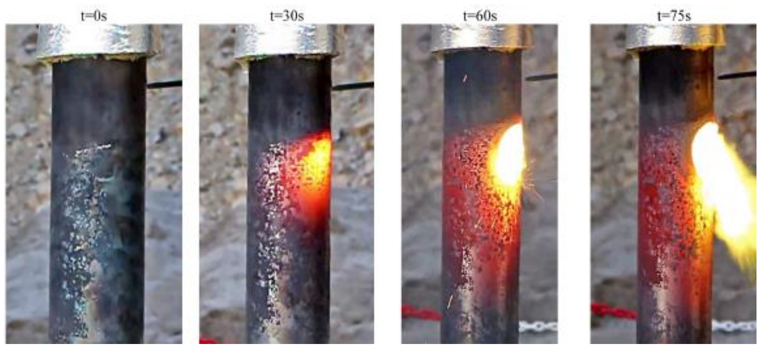


Figure 3.7: Time evolution of casing milling in air environment (Kocis et al. 2015)

- Gajdos et al. (2015a) presents tubular milling in a water environment at atmospheric pressure, Figure 3.8.

Figure 3.8: Water environment casing milling setup and results. During the same experiment it was shown that 3.5" tool was capable of milling 4.5" 5.5" and 7" casing (Gajdos et al. 2015a)

- Gajdos et al. (2015b) presents milling of casing and cement in a brine environment at atmospheric pressure, Figure 3.9.

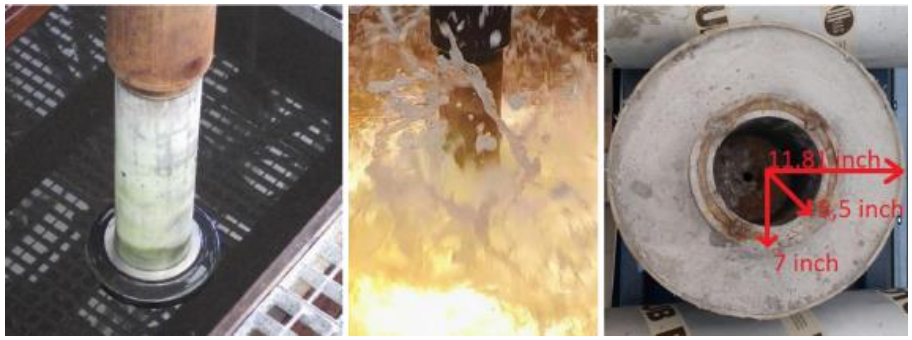


Figure 3.9: Plasma-based milling generator submerged in brine environment; milling specimen on far right (Gajdos et al. 2015b)

- Gajdos et al. (2016) presents experiments done in a pressurized (2 – 20 MPa) brine environment.

- Kristofic et al. (2016) presents the latest publication available. Tests of milling steel with mud contaminated cement behind and its effect on the process in a pressurized (25 – 42 MPa) brine environment.

An offshore field trial is scheduled for first half of 2018 (Kristofic et al. 2016). At the present time the main focus is testing of longer section milling as well as testing the complete system in high pressure environment. This will include full scale BHA and a test well.

Table 3.1: Electric plasma miller advantages and limitations

	Advantages	**Limitations**
Electric plasma miller	• Steel removal downhole • Casing access without pulling tubing • Rigless, well intervention setup • Advantageous cuttings size and shape compared to swarf • 3.5” tool capable of milling 4.5”, 5.5” and 7” tubular.	• Not commercialized • No field trials • High energy consumption • Transferability of energy to tool downhole could be challenging • Specialized umbilical needed for plasma milling operation • Heat-effect from milling on surrounding casing and cement not known • Weight of umbilical CT reel

3.2 Thermite plug

Using thermite for wellbore sealing by melting materials in the wellbore and its vicinity is a radical idea. A Norwegian company presented the idea for P&A purposes in 2012 with the aim for rigless operations. The purpose of the technology is to make an impermeable "man-made rock" with a smooth transition between formation and plug (Mortensen 2016). A JIP was initiated in 2014 including several major NCS operating companies and the Norwegian Research Council. Very little scientific data have been published on their approach and R&D progress. This thesis will therefore mainly focus on an American research company's approach for wellbore sealing using thermite for nuclear waste management (Lowry et al. 2015). Although nuclear waste is stored in granite rock the analogies to an oil & gas well are evident, as plug placement and interaction with formation will be based on the same principles.

3.2.1 Thermite

"Thermit" was first described by Hans Goldschmidt in 1908 as an exothermic reaction involving reduction of metallic oxides with aluminum to form aluminum oxide and metals (Wang et al. 1993). A large heat release that will heat the products above their melting point is what categorizes these reactions. Temperatures in excess of 3000°C (3273K) can be obtained during an aluminum and iron-oxide reaction, which is above the melting point for the products of this reaction. Originally used as a method for forming metal alloys in a carbon free environment, it has also been used in railroad welding, steel structure demolition and military applications (Lowry et al. 2015). Today *thermite* is used in a broader description and can be defined *as an exothermic reaction which involves a metal reacting with a metallic or non-metallic oxide to form a more stable oxide and the corresponding metal or non-metal of the reactant oxide* (Weng et al. 1993). It is a self-oxidizing reaction with high specific heat and the ability to react under water (Lowry et al. 2015). This oxidation-reduction reaction can be written in general form as:

$$M + AO \rightarrow MO + A + \Delta H \tag{3.4}$$

Where M is a metal, and A is either a metal or a non-metal. AO and MO are their corresponding oxides and ΔH describes the heat generated (enthalpy). Goldschmidts reaction, containing aluminum and iron-oxide is described below:

$$2Al + Fe_2O_3 \rightarrow 2Fe + Al_2O_3 + \Delta H \tag{3.5}$$

This reaction is the most relevant for wellbore sealing in a commercial and safety point of view as the reacting agent is readily available and the oxide is chemically and physically stable. The reaction (3.5), above, has an adiabatic combustion temperature of 3622K. The iron and aluminum-oxide products have melting points of 1809K and 2315K, respectively (Weng et al.

1993). This means that all elements included in the process will be in a melted state. The self-sustained nature of a thermite reaction can be adjusted by adding an inert diluent or salts of alkali metals. Alkali metals such as NaF or KCl or alkaline earth metals such as AlF_3 will effectively increase the combustion rate of the reaction (Weng et al. 1993). An inert diluent, such as Al_2O_3, will slow down the reaction and lead to a lower combustion temperature (Lowry et al. 2015). The adiabatic combustion temperature does not only give a quantitative measure of the exothermicity of the reaction, it also gives a quick determination of the reactions ability to self-propagate. A general rule is that an adiabatic temperature above 2000K will lead to a self-propagating thermite reaction (Weng et al. 1993). Once the reaction is complete a rigid hot plug of metal and oxide is formed, a ceramic-like material (Lowry and Dunn 2016).

Initiation. Weng et al. (1993) describes four different classifications for the physical and chemical stability of the reactant oxides. Oxides in the reaction, listed in equation 3.5 above, are classified as physical and chemical stable. "Stable" means it is one of the reactions needing the most energy for initiation, as illustrated in Figure 3.10. Thermite reactions can be initiated by a combustion wave from a chemical reaction, an electric current, radiation energy (laser) or mechanical impact. Sparks created by a hammer striking an aluminum residue on rusty mild steel have been blamed for initiating thermite reactions in chemical plants and mines (Weng et al. 1993).

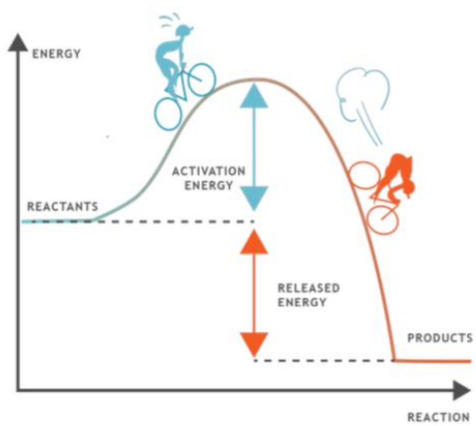


Figure 3.10: Illustration of the activation energy needed to initiate the thermite reaction (Mortensen 2016).

Combustion. Weng et al. (1993) state that *"The high exothermic energy associated with thermite reactions and, in general, the condensed nature of the reactants and products at the reaction temperature make many thermite systems examples of reactions in the gasless combustion regime".*

Gasless combustion defining criteria is:

$$P(T_c) \ll P_0 \quad (3.6)$$

Where P is the vapour pressure of the most volatile component at combustion temperature T_c, and P_0 is the external gas pressure. The reaction described in equation 3.5 diluted with its product (Al_2O_3) is an example of a gasless combustion. Experiments have been done showing the reactions combustion rate independence to inert gas pressure, Figure 3.11.

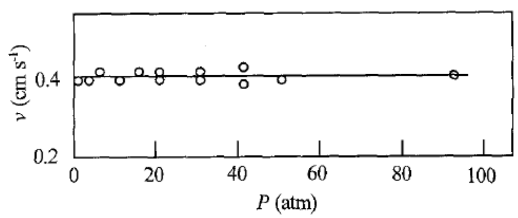


Figure 3.11: Combustion velocity of ($2Al + Fe_2O_3$) diluted with 30 weight% (Al_2O_3) as a function of inert ambient pressure (Weng et al. 1993).

Although the thermite reaction itself does not create gas during combustion the surrounding fluids in a well will be affected by the combustion temperature. Saturated water has a critical temperature (T_{cr}) of 374.14°C (648.29K) and a saturation pressure (P_{sat}) of 22,090 kPa (220.9 bar) (Çengel et al. 2012). Well fluids in close vicinity to the reaction will reach a *supercritical fluid* state on typical NCS reservoir barrier depths, illustrated in figure 3.12. At lower pressures (shallower depth) the well fluid in surrounding area to the reaction would still reach a *gaseous phase* also called superheated vapour.

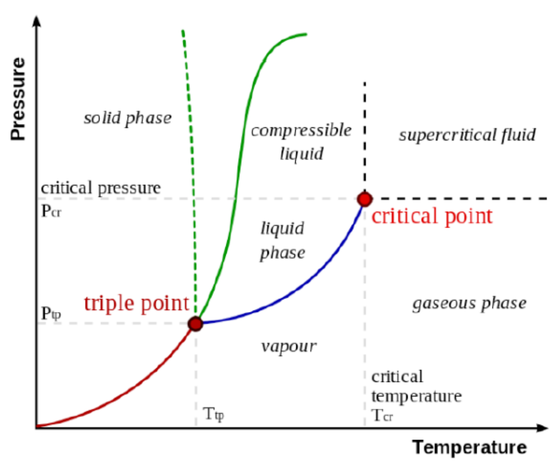


Figure 3.12: Pressure-temperature phase diagram showing the critical point and area of supercritical fluid (Mortensen 2016).

Solids from melts. Before trying to create a man-made rock barrier, one must understand how nature creates rock. Rock solidified from magma is called igneous rocks. One of the founding fathers of geology, James Hutton, discovered a granite layer cutting across and disrupting a sedimentary rock. The granite, which is an igneous rock, had somehow fractured and invaded the sedimentary rock, Figure 3.13. By closer investigation it became evident that the mineralogy of the sedimentary rock close to the granite was different. These changes he concluded were a result from great heat (Grotzinger and Jordan 2010).

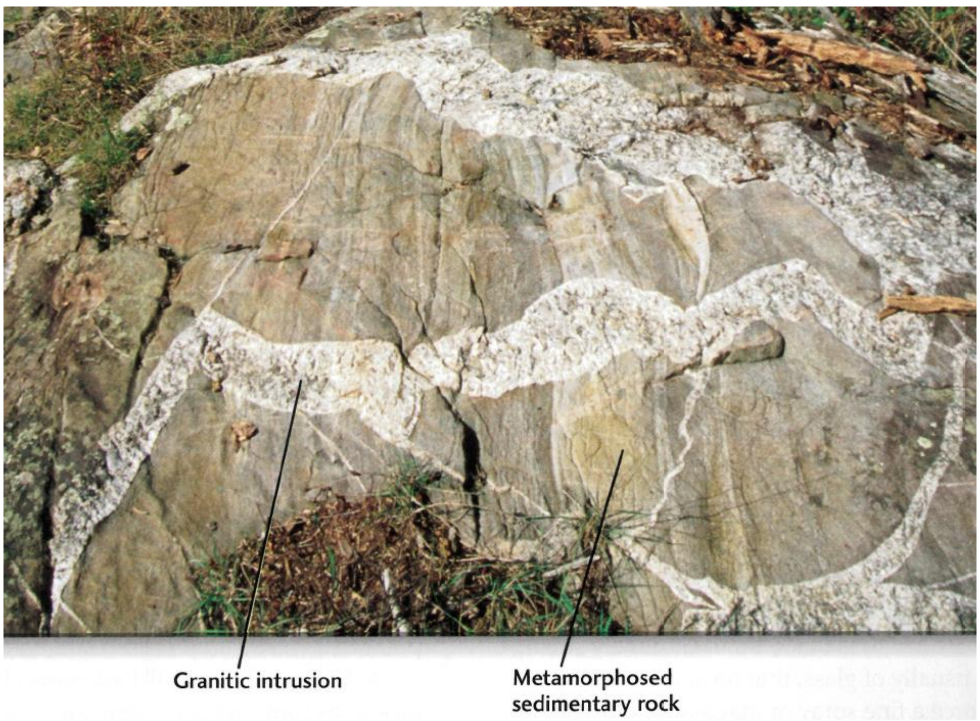


Figure 3.13: Granitic intrusion in a metamorphosed sedimentary rock (Grotzinger and Jordan 2010)

Magma is rock in fluid form. By lowering its temperature it starts to crystalize and solidify, much like water when it freezes to ice. The rate of solidification (cooling) will affect the crystal structure and size. The exact mechanisms of rock melting and solidification are not yet fully understood, but it is known that a rocks melting point depends on its chemical and mineral composition, and pressure and temperature (Grotzinger and Jordan 2010). A rock does not melt completely at once, its different minerals with its different melting points is leading to partial melting, illustrated in the crystallization process in Figure 3.14. It is also dependent on water content, which will lower its melting point, according to Figure 3.15. Water content is a significant factor in sedimentary rock melting, as it contains more water in its pores than igneous or metamorphic rocks (Grotzinger and Jordan 2010). Igneous rocks typically have a melting temperature of 700-1200°C (~1000-1500K), and sedimentary rocks will be in the same region depending on composition.

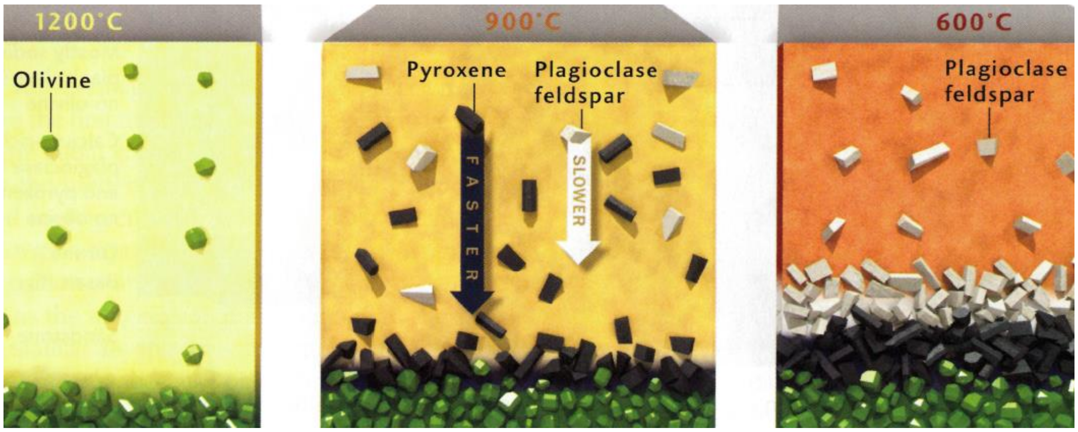


Figure 3.14: Fractional crystalization according to temperature. Crystallization settling rate can be calculated using Stoke`s law (Grotzinger and Jordan 2010).

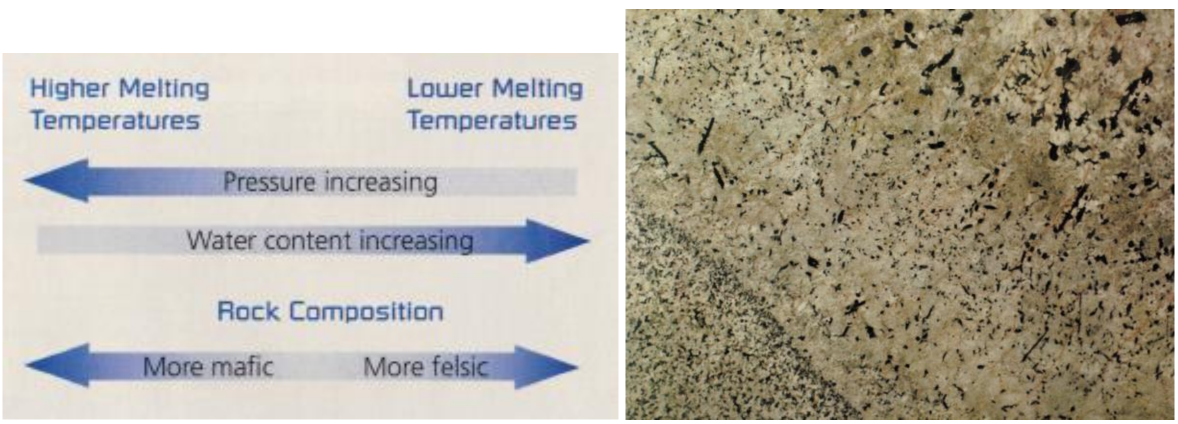


Figure 3.15: (Left) Factors affecting melting temperature of rocks. (Right) Granite pegmatite vein. The center of the intrusion (upper right) cooled more slowly and developed coarser crystals. The margin of intrusion (lower left) has finer crystals due to more rapid cooling (Grotzinger and Jordan 2010).

All of the above mentioned aspects need to be considered when aiming to create a cross-sectional barrier using thermite. A key area of research will be how to create a smooth interface between thermite plug and the surrounding rock.

3.2.2 Thermite for wellbore sealing in P&A

As described above the concept uses thermite as a means of restoring cap rock functionality. The reactants need to be placed adjacent to the formation in which it is supposed to form a seal with. The concept is to lower thermite powder in a container to desired depth by means of wireline or coiled tubing where it will rest on a pre-set heat-insulated platform, as illustrated in Figure 3.16 (Skjold 2013; Lowry and Dunn 2016). Upon reaction initiation, it will reach temperatures above its melting point and the material compacts into the borehole volume, where it sets and cools. Lowry et al. (2015) list some important factors that influence the performance of a thermal plug:

- The plug matrix formed is of low porosity and low permeability
- Effective bonding of plug to the borehole wall. Bonding both mechanical and sealing.
- Thermal/structural impact to the surrounding rock. Minimal or no impact is preferred.

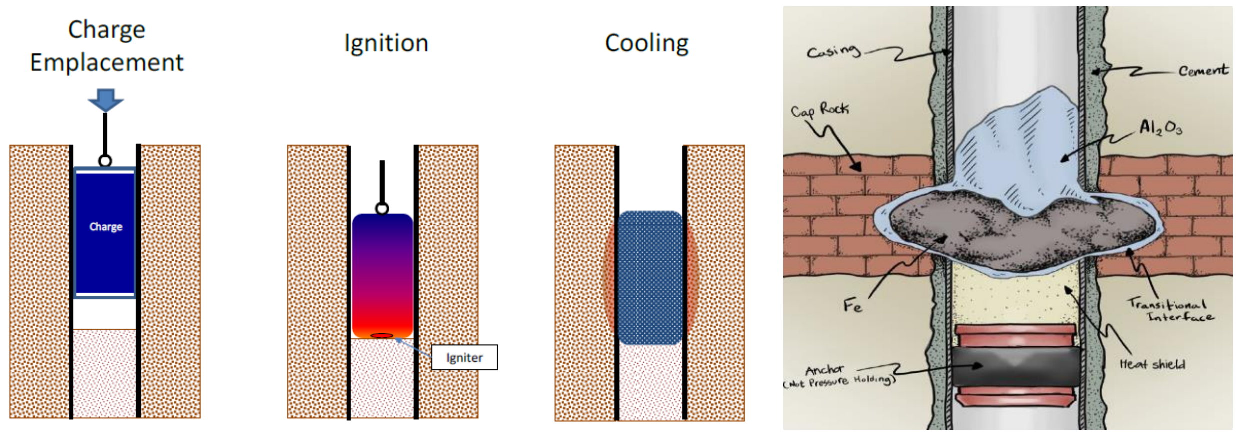


Figure 3.16: (Left): Plug emplacement technique (Lowry et al. 2015), (Right): Illustration of the resulting plug using a thermite reaction. The heat insulating material on top of plug is also shown (Log 2016).

For a TT and XT WL conveyance placing barrier plugs according to NORSOK D-010 (2013) several runs would be needed. Skjold (2013) estimate 1.85 m^3 of heat generating mixture is needed to form a 50m barrier in 9-5/8" (0.037m^3/m) casing. Estimating a WL container tool with internal diameter of 3" (0.0762m) and a length of 20m, approximately 20 runs would be needed to place the mixture. The length specifications in NORSOK (2013a) have been made with cement plugs in mind, so the need for 50m thermite plug could be discussed. In this thesis case study the plugs will be placed according to NORSOK D-010 (2013).

$$Number\ of\ runs = \frac{Volume\ of\ plug}{Volume\ of\ container} = \frac{V_{9-5/8''}}{\frac{\pi * D^2}{4} * L} = \frac{1.85m^3}{0.0912m^3} = 20.3\ runs \tag{3.7}$$

In the following section the techniques described by Lowry and Dunn (2016) and Skjold (2013) to place a thermite plug with the above mentioned factors will be reviewed.

Applying a vertical load on top of the reaction will lead to a less porous product. A weight of approximately 500-1500kg is resting on top of the thermite reaction, compressing it and assisting the melt forcing its way into well surface irregularities. A relatively high porous plug will reduce its potential strength and cause it to be permeable. By adding a diluent to the reaction, like metal oxides or eutectic materials, lowering the reaction temperature the plug will stay in a liquid or viscous state for longer. This will insure the plug being firmly pressed towards the surrounding rock (Lowry and Dunn 2016).

Diluting the thermite mixture will effectively reduce the peak reaction temperature. The stoichiometric mix of red iron oxide (Fe_2O_3) and aluminum powder is approximately 3:1 by mass, respectively (Lowry and Dunn 2016). This reaction will, in atmospheric conditions, have a relatively fast and violent reaction which could be difficult to contain. In wellbore sealing, containment is vital in creating a monolithic plug material. Dilution can reduce the above mentioned reaction peak temperature from 3000°C (3273K) to less than 1700°C (1973K). The dilution will lead to a lower burn rate of 0.1 cm/s in comparison to raw mixture 10-100cm/s. The lower temperature is also proposed in a layered thermite plug setup, where different dilutions are used for different purpose in the same plugging operation. The first mixture is set up to expand radially and effectively swage the casing outwards to the borehole wall in case of un-cemented annulus (Lowry and Dunn 2016). The next mixture in the layered setup creates the plug.

Radial expansion of the plug is preferred before axial expansion. A thermite reaction will expand in the direction of reaction propagation. An axial length expansion of 10-20% will occur on a cylindrical plug ignited in one end with very little expansion in the radial direction. By igniting the mixture by means of a hot wire running along the center axis of the cylindrical plug one would achieve radial expansion ensuring a tight fit inside the borehole (Lowry and Dunn 2016).

In addition, other means of ignition and placement are proposed in the literature. Lowry and Dunn (2016) presents a self-feeding reaction from a cylindrical container. As it is ignited in bottom, it will self-feed by gravity. Skjold (2013) also presents plug placement by fluid mixture and circulation. A fluid placement by CT would be preferred looking at the number of WL runs needed when working in accordance with NORSOK D-010 (2013). The mixture could also be ignited by a timer, regardless of it being circulated in place or not (Skjold 2013).

3.2.3 Research and development of thermite plug

Several aspects of the thermite plugs ability to create a seal in granite rock have been presented by Lowry et al. (2015). This research is mostly in regards to sealability in granite rock for nuclear waste disposal, but analogies can be drawn to oil & gas well sealing.

The effects of diluting a thermite mixture to obtain beneficial properties were a key aspect in the initial development phase. Dilutions by as much as 1:1 with silica and alumina proved to lower the peak temperature of the reaction, Figure 3.17. The mixture proved to be self-sustained in dilutions up to 51%, resulting in a slower and more controllable reaction. Compressive strength tests of the samples showed the effect of dilution, where silica proved to produce a relatively weaker matrix according to Table 3.2. On the other hand silica diluted matrix showed favorable results with regards to permeability, Figure 3.18. In addition simulations on radial temperature effects and the cooling have been done, showing that plug-rock interface cooled to 700-800°C (~1000-1100K), within an hour after the reaction (Lowry et al. 2015)

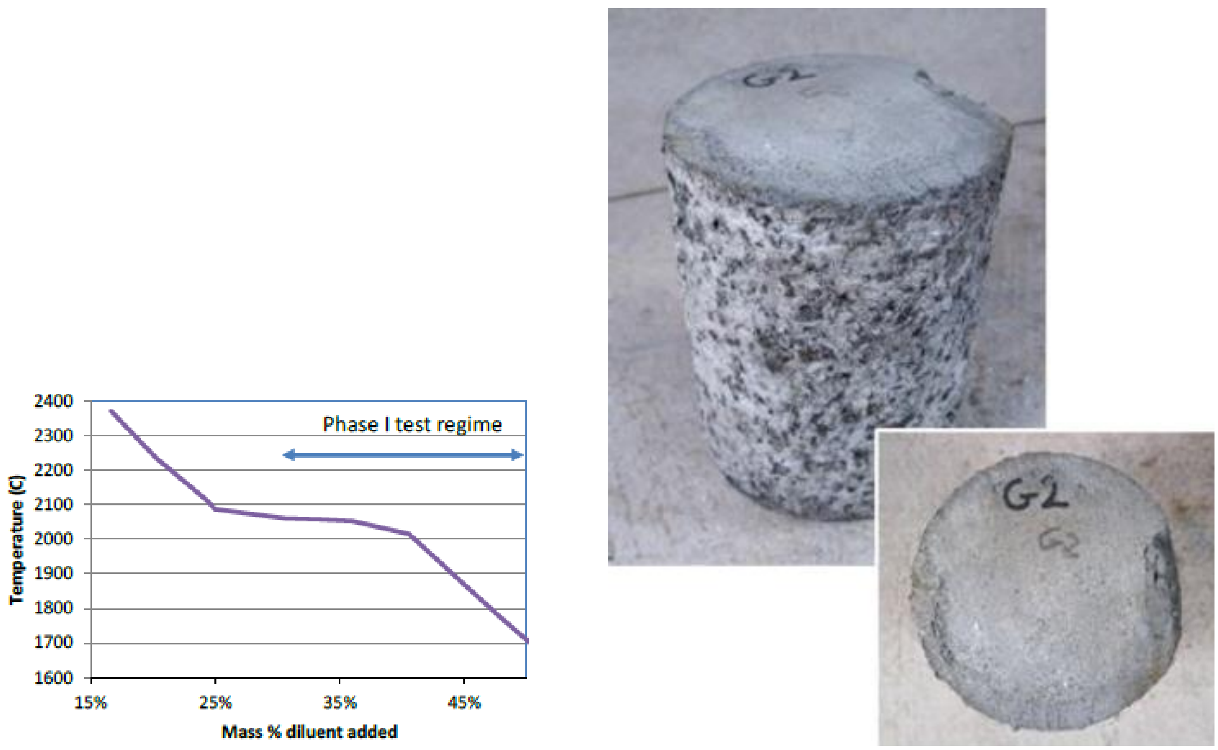


Figure 3.17: (Left) Adiabatic reaction temperature as a function of dilution by aluminum oxide. Plateau at 2100°C represents the melting temperature of aluminum. (Right) Thermal plug sample removed from granite block test very fine matric structure due to diluted mixture (Lowry et al. 2015)

Table 3.2: Ultimate unconfined compressive strength of thermite plug samples (Lowry et al. 2015).

Plug Reactants	Compressive Strength (MPa)
High dilution SiO_2 (1 sample)	46.21
Medium dilution Al_2O_3 (3 samples)	67.97 ($\sigma = 0.99$)
High dilution Al_2O_3 (1 sample)	75.89

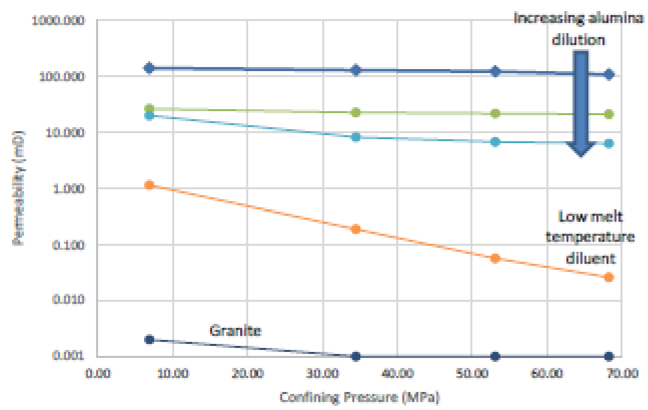


Figure 3.18: Increasing dilution of the system with a low melt temperature oxide (silica) yielded low permeability in confined tests (Lowry et al. 2015).

The R&D company developing thermite plug for oil & gas well P&A has also researched the effects of fluids reaching super critical state during the exothermic reaction in a pressurized wellbore. To better understand the reaction in wellbore environment a test cell was built, Figure 3.19, capable of reaching 100°C and 700 bar (Mortensen 2016). The cell was built with an integrated accumulator able to handle the gaseous superheated fluids. No results from these tests have been published.

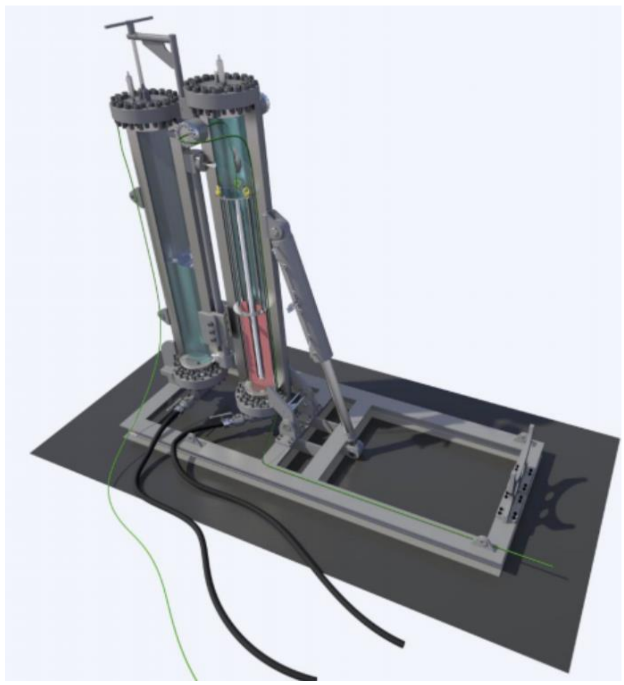


Figure 3.19: Pressure cell built to simulate wellbore environment to research reaction in well condition (Mortensen 2016)

In 2016, a field test on two land wells in Canada was performed. In these trial wells the tubing was pulled, using heavy equipment, to gain direct access to a cemented casing interval. This is a step in R&D towards setting the thermite mixture inside tubing and creating a rock-to-rock barrier. After the tubing was pulled, the thermite mixture was successfully placed and ignited, creating a solid barrier (Log 2016). The results were encouraging, as the plug was set in a controlled manner without incidents. In the first well, two consecutive plugs were set as the first was not holding pressure. A total of 3 plugs were set in two different wells. The verification methods and criteria are presented in Figure 3.20. The results are presented in Figure 3.21 (Log 2016). The future plan is to monitor the wells over a longer period and modify the tool for better control of internal pressure (Log 2016). Further test are also planned.

Test	Method	Acceptance
Plug location	Tag with tubing	5 tonne weight test
Plug integrity	Positive pressure test to 7000 kPa	15 mins +/- 350kPa stabilized
Plug integrity	Inflow (negative pressure) test minimum 7000 kPa diff	15 mins +/- 350kPa stabilized 60 day continous monitoring
Casing Inspection - Cement bond	Before and after Radial Bond & Casing Inspection log	Baseline comparison – independent log analysis
Casing and plug integrity	Visual inspection with video camera	No casing damage. No gap between plug and casing. Competent top surface of plug
Upper well integrity	Before and after Vent Flow & Gas Migration tests	No measurable gas at surface
Seismic Effect	Geophone Array on lease	No seismic response above background

Figure 3.20: Pilot well verification method and acceptance criteria (Log 2016)

	Barrier 1	Barrier 2	Barrier 3
Well	Whitehorse	Whitehorse	Benjamin
Depth	2157m	2150m	2132m
Pre-charge pressure	220	206	196
Tag	OK	OK	OK
+ve Pressure Test	Failed	Failed	OK
-ve Pressure Test	Failed	Failed but improving	OK
CBL	OK	OK	OK
Casing log	OK	OK	OK
Gas Migration	OK	OK	OK
Vent flow	OK	OK	OK
Seismic event	OK	OK	OK

Figure 3.21: Thermite plug field trial results as of October 2016 (Log 2016).

Table 3.3: Thermite plug advantages and limitations

	Advantages	Limitations
Thermite plug	• Possible to create a "man-made rock" for wellbore cross-sectional sealing • Can obtain a favorable plug design/properties by diluting thermite • WL based concept • Rigless, through tubing • Encouraging field trials	• Not commercialized • WL concept not practical when complying with NORSOK D-010 (2013a) • Uncertainty with regards to its ability to create a cross-sectional barrier in presence of fluid filled annulus, as concept aim for placement in tubing • Un-intended ignition on surface could lead to incidents • Not implemented in current P&A regulations

4. Case studies

In this chapter, three wells will be plugged as a case study. The candidate wells are provided by NCS operating companies, but anonymized for the purpose of this thesis. These wells have already been plugged, as part of batch P&A campaigns. Chapter 4 will present the wells and the conventional approach used for P&A purposes of each respective well. The conventional approach will only be presented briefly. The chapter will also investigate the possibility for a rigless through tubing P&A approach using some of the emerging technologies presented in Chapter 3 combined with the conventional technologies presented in Chapter 2. Well barrier schematics will be presented for the wells prior to and after P&A for a better visualization of the operations.

When aiming for a through tubing (TT) P&A approach several challenges arise. One obvious challenge is that the drilling rig with associated mud handling equipment is removed. Over-balanced mud and drilling BOP are often used as barriers during conventional P&A operations. In addition to its potential barrier function, mud contributes to hole stability and hole cleaning in open-hole operations. A rigless approach should aim to be mud-less using brine as well fluid instead of mud as mud handling equipment will use a lot of deck space. A mud-less operation should be performed in cased hole only, as hole stability and pore pressure will not pose the same challenge in a cased hole- as in an open hole operation. A TT P&A cased hole operation can utilize the existing XT in addition to well intervention pressure control equipment (PCE) as WBE.

In most cases, leaving the tubing in the well is not an option. The need for annular barrier verification, often in combination with control lines passing through the plug setting area, identify the need to remove the tubing. In a TT P&A perspective a section of the tubing will have to be removed somehow. By removing only a section of tubing, the tubing hanger and tubing with all of its components will form a restriction throughout the operation. All tool used in the TT P&A operation will have to pass these restrictions to reach the plug setting area. In Table 4.1 the challenges with regards to a rigless P&A operation and possible solutions are listed.

All depths in this chapter will be referring to measured depth (MD) rotary kelly bushing (RKB) unless otherwise specified. Phase 3 P&A, wellhead and conductor removal, will not be part of case study.

Table 4.1: Challenges with rigless P&A and possible solutions

	General challenges	Possible solution	Possible challenges with the proposed solution
Rigless P&A	• No drilling rig with associated equipment to supply mud as over-balanced fluid column during P&A operation. Mud need pits, pumps and shakers. NCS P&A operations are commonly run with over-balanced mud as well fluid. Mud will contribute to well control in addition to its functions with regards to hole stability and hole cleaning.	• Run operation with well intervention equipment as primary barrier and XT intact. • Well filled with brine/seawater. • Rigless P&A run as cased hole operation only (will not have to consider pore pressure and hole stability). • By keeping the operation cased hole (and mud free) a lot of deck space is saved.	• If a cased hole operation is not possible then a rigless approach should be reconsidered. • If annular barriers in desired plugging area are not in-place, it could be difficult to provide a cross-sectional barrier using a rigless approach. • Hole cleaning will be difficult due to relatively low circulation rate and low viscous fluid (brine). Hole cleaning in a "drilling perspective" (formation cuttings) not needed due to cased hole operation. Some hole cleaning in plug setting area might be beneficial.
Rigless through tubing P&A	• Not able to log annular barrier (cement) through tubing wall. Needs access to casing wall. • All tools used in rigless through tubing P&A must be able to pass tubing restrictions.	• Remove section of tubing to gain access to casing/cement in question, to log it.	• Tool OD vs. Tubing restrictions ID. • Centralization of tool in casing ID (centralizer to pass tubing ID and still centralize tool in csg. ID.) • Distance between csg. ID and slim logging tool OD (might affect logging quality). • Re-entering tubing while POOH with tools.

4.1 Plug and abandonment of well A-1

The well was completed as an oil producer. It was shut in because of high water-cut and decided to be plugged in a batch P&A operation. The well schematic is presented in Figure 4.1 and summarized in Table 4.2. The overburden formation (OBF) of A-1 consists of one formation with potential to flow and a water bearing zone. These formations are given numbers for an easier overview.

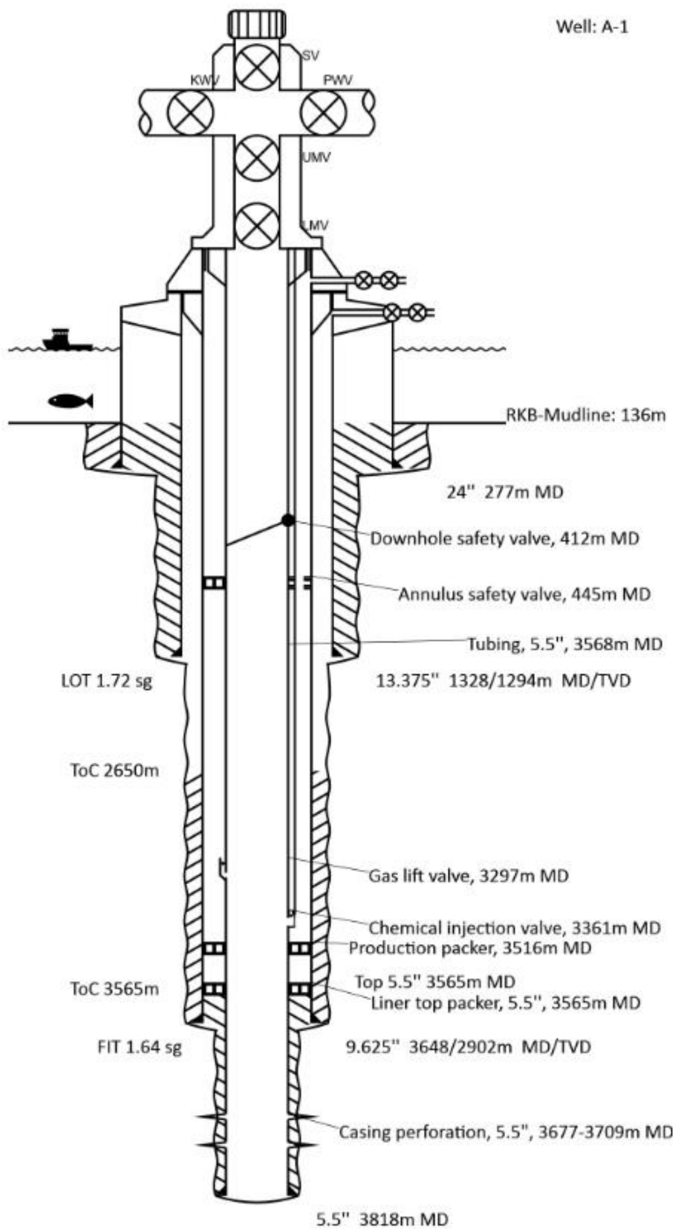


Figure 4.1: Well schematic A-1. Produced with *Wellbarrier* software.

Table 4.2: A-1 Well summary table

Description		Depth
13-3/8" csg.	Shoe @	1328m / 1294mTVD
	TOC @	136m
9-5/8" csg	Shoe @	3648m / 2902mTVD
	TOC @	2650m
5-1/2" Liner	Hanger @	3565m
	Shoe @	3818m
	TOC@	3565m
5-1/2" prod. tubing	DHSV @	412m
	ASV @	445m
	GLV @	3297m
	DHPG @	3329m
	CIV @	3361m
	Prod. Packer @	3516m
	WEG	3568m
Reservoir	top @	3677m / 2886mTVD
Perforation interval		3677 - 3709m
Formation (Fm) with potential in overburden.	Fm top @	
OBF #1		3320m / 2540mTVD
Formation without potential, but water bearing.	Fm top @	
OBF #2		1070m
Estimation of minimum setting depth based on:		
Gas density	0.23 s.g	
LOT	1.72 s.g	1294mTVD
FIT	1.64 s.g	2902mTVD

Gradient curves showing pore pressure and fracture pressure were not available as part of the data package received for well A-1. Minimum setting depth was estimated based on available information. Pore pressure in OBF #1 was estimated from reservoir pressure, minus hydrostatic head of seawater.

Estimated minimum setting depth for base of secondary reservoir barrier:

$$Reservoir\ pressure - hydrostatic\ head\ of\ gas\ \leq Formation\ fracture\ pressure$$

$$320bar - 0.23sg * 0.0981 * (2886mTVD - X) \leq 1.64sg * 0.0981 * X$$

$$X\ \geq 1872.8m\ TVD$$

Estimated minimum setting depth for base of secondary intermediate barrier:

$$Pore\ pressure - hydrostatic\ head\ of\ gas\ \leq Formation\ fracture\ pressure$$

$$285bar - 0.23sg * 0.0981 * (2540mTVD - X) \leq 1.64sg * 0.0981 * X$$

$$X\ \geq 1646.2m\ TVD$$

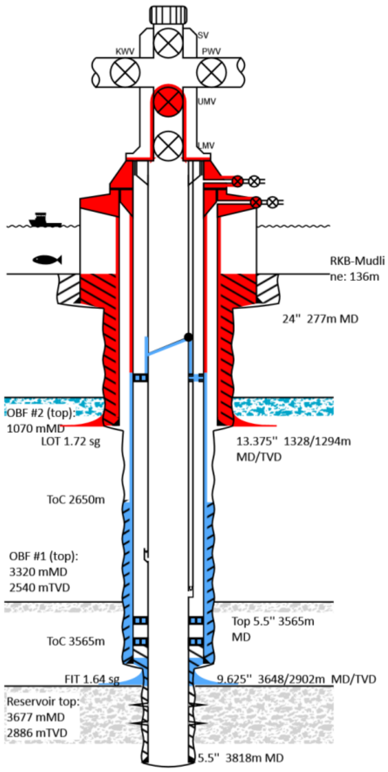
Well status pre-P&A:

- Oil/water/gas in tubing, injection gas in annulus-A
- Downhole safety valve (DHSV) tested OK
- Annulus safety valve (ASV) tested OK
- Downhole pressure gauge (DHPG) and chemical injection valve (CIV) with no control line issue.
- Side pocket mandrel (SPM) with gas lift valve (GLV) installed.
- Reservoir temperature: 127°C
- Reservoir pressure: 320 bar
- No sustained casing pressure (SCP) observed.
- Injectivity test performed OK

The well status is illustrated in the well barrier schematic (WBS) Figure 4.2.

Universitetet i Stavanger

Field : Wittberg	Well design pressure 345 Bar
Well : A-1	Reservoir pressure 320 Bar
Schematic : US.P 4.1-a2 rev. 1	Prepared By : Stian Wittberg
Date : 18.May.2017	Verified By :



Producer

Producer

Planned - Current

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test to 70 bar	Tubing pressure
Annulus safety valve	Inflow test to 70 bar	Periodic inflow testing
Tubing	Pressure test to 345 bar	A-annulus pressure
Production packer	Pressure test to 345 bar	A-annulus pressure
Liner top packer	Pressure test to 265 bar	A-annulus pressure
Production casing	Pressure test to 265 bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production liner cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Suspension x-mas tree	Pressure test to 345 bar	Pressure tested to 345 bar
Spool wellhead A with access valve	Pressure test to 265 bar	External observation
Spool wellhead	Pressure test to 265 bar	External observation
Casing hanger	Pressure test to 265 bar	A-annulus pressure
Production casing	Pressure test to 265 bar	B-annulus pressure
Surface casing	Pressure test to 265 bar	B-annulus pressure
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:

Initial qualification test pressures not available in data package. All pressures estimated based on relevant EAC and given well data.

Depth reference is RKB Jack up rig

Depth correlation RKB - MSL 52.2 m

Prepared by Universities

Figure 4.2: WBS of A-1 prior to P&A operation. Produced with Wellbarrier software.

4.1.1 Conventional approach to P&A A-1

As part of a batch P&A campaign it is common to prepare the well for P&A using stand-alone well intervention. This pre-P&A phase include temporarily plugging the well to be able to remove XT and installing drilling BOP. The pre-P&A operation step list will be as follow:

- Rig up wireline equipment
- Drift well
- Bullhead tubing to seawater
- Install deep set bridge plug in 5.5" liner above top reservoir and pressure test same
- Punch ASV and pressure up to release
- Run tubing cutter and cut tubing above production packer
- Install hold open sleeve in DHSV
- Install shallow set "pump open" bridge plug and test same.
- Rig down wireline equipment
- Displace well to kill mud

The well is now secured and the XT can be removed. A "pump open" bridge plug could either be set up to open at a given pressure, or with a smart sub opening and closing at certain pressure cycles. The following sequence is rig based and in this case performed by a jack-up rig. A step list with an associated time estimate is presented in Appendix E. Phase 1 and 2 for reservoir and intermediate permanent plugging will for A-1 be as follows:

- Skid rig, nipple down XT and nipple up BOP
- Retrieve tubing down to P&A depth
- Clean out run in 9-5/8" casing. Clean plug setting area.
- Run ultrasonic cement bond log
    - Confirm TOC and Check for creeping shale above cement.
- Set a continuous (back-to-back) cement plug above tubing cut to act as primary and secondary barrier for reservoir and overburden formation number one (OBF #1). TOC to be minimum 100m above top of OBF #1
- Dress off and tag cement. Pressure test plug to LOT + 70bar.
- Cut 9-5/8" casing in area above 13-3/8" csg. shoe.
- Set casing bridge plug in 13-3/8" and pressure test same
- Displace well to seawater
- Set a cement plug above 13-3/8" bridge plug to act as primary barrier for OBF #2 and as open hole to surface barrier. TOC to be minimum 50m above top OBF #2
- Pressure test plug to LOT + 70bar.

The well status after P&A operation is showed in WBS Figure 4.3.

Universitetet i Stavanger

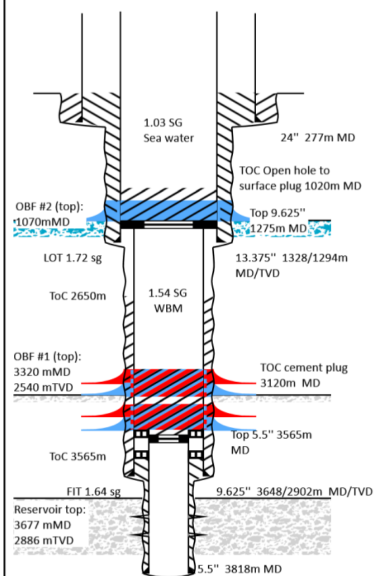
Field : Wittberg
Well : A-1
Schematic : US.P 5.7-a1 rev.1
Date : 18.May.2017

Well design pressure 345 Bar
Reservoir pressure 320 Bar
Prepared By : Stian Wittberg
Verified By :

Permanent abandonment

Jack up rig P&A operation

Draft



Primary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 180 bar	Pressure above plug
Cement plug	Pressure test to 180 bar	Pressure above plug
Cement plug	Pressure test to 145 bar	Pressure above plug
Production casing	Pressure test to 180 bar	B-annulus pressure
Production casing	Pressure test to 180 bar	B-annulus pressure
Surface casing	Pressure test to 145 bar	B-annulus pressure
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 180 bar	Pressure above plug
Cement plug	Pressure test to 180 bar	Pressure above plug
Production casing	Pressure test to 180 bar	B-annulus pressure
Production casing	Pressure test to 180 bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:
Pressure test cement plugs to LOT + 70 bar

Depth reference is RKB Jack up rig
Depth correlation RKB - MSL 52.2 m

Prepared by Universities

Figure 4.3: WBS of A-1 after jack-up rig plugging operation. Produced using Wellbarrier software

4.1.2 Rigless approach to P&A A-1 using emerging technologies

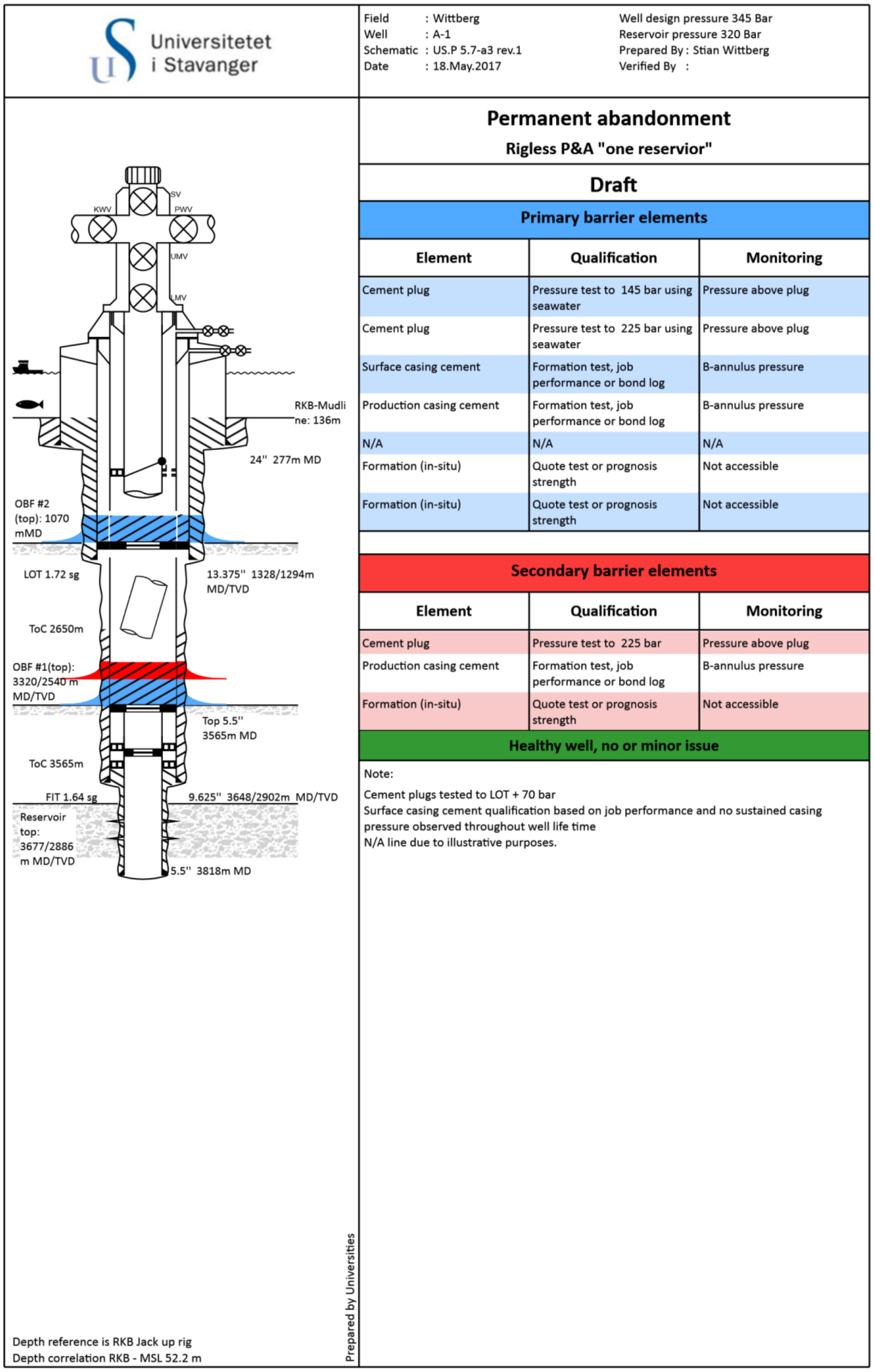
In this section, an operational step list will be presented using well intervention equipment and plasma miller. The aim is to plug the well according to NORSOK D-010 (2013a) requirements. Status prior to P&A will be exactly the same, as presented in Figure 4.2. In this approach, there is no need for a pre-P&A temporary plugging activity as all operations are run through XT. The surface equipment for this operation will consist of: wireline package, CT unit and a cement unit with associated pits. The CT unit must be set up with both conventional CT reel and a reel for plasma bit umbilical.

Operational step list for rigless TT P&A approach on A-1:

A more detailed step list and calculations performed are attached in Appendix F

1) Rig up wireline
2) Drift well for bridge plug and plasma bit
3) Bullhead tubing to seawater
4) Set bridge plug in 5-1/2” Liner above perforations. Pressure and inflow test plug.
    a. Alternatively bullhead cement into reservoir up to liner hanger.
5) Punch tubing above production packer
6) Displace annulus gas (lift gas) to seawater
7) Disintegrate tubing using plasma bit. Remove minimum 100m tubing above top of OBF #1.
8) Jet wash plug setting area using CT.
9) Run ultrasonic bond log with multifinger caliper for cement evaluation
10) Set inflatable plug to act as base for cement plugs, and test same.
11) Set 50m cement plug acting as primary barrier for reservoir and OBF #1.
12) Tag and pressure test primary cement plug to LOT + 70 bar.
13) Set a 50m cement plug, on top of primary cement plug, to act as secondary barrier for reservoir and OBF #1.
14) Tag and pressure test secondary cement plug to LOT + 70 bar.
15) Disintegrate minimum 50m of 5-1/2” tubing in area above top of OBF #2.
16) Disintegrate minimum 50m of 9-5/8” production casing in same area.
17) Jet wash plug setting area
18) Set inflatable plug to act as cement base in 13-3/8” casing.
19) Set a 50m cement plug to act as both primary barrier for OBF #2 and open hole to surface plug.
20) Tag and pressure test plug to LOT + 70 bar
21) Rig down equipment

The well barrier schematic in Figure 4.4 shows the well status after the operational sequence listed above.



Field : Wittberg
Well : A-1
Schematic : US.P 5.7-a3 rev.1
Date : 18.May.2017

Well design pressure 345 Bar
Reservoir pressure 320 Bar
Prepared By : Stian Wittberg
Verified By :

Permanent abandonment

Rigless P&A "one reservior"

Draft

Primary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 145 bar using seawater	Pressure above plug
Cement plug	Pressure test to 225 bar using seawater	Pressure above plug
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
N/A	N/A	N/A
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to 225 bar	Pressure above plug
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:
Cement plugs tested to LOT + 70 bar
Surface casing cement qualification based on job performance and no sustained casing pressure observed throughout well life time
N/A line due to illustrative purposes.

Figure 4.4: WBS of A-1 after rigless P&A operations. Produced using Wellbarrier software

4.1.2.1 Discussion on rigless approach to P&A A-1

Some of the operations and possible challenges or decisions to be made will be further discussed below.

Plasma miller. The plasma miller is the key component in the rigless approach presented for A-1. The radial reach of the plasma is possible to control to some extent, but heat will affect the production casing, laying on low side, as shown in lab experiments presented in Chapter 3. In addition, the casing cement may be deteriorated due to the generated heat. The production casing and the casing cement used as WBE in the case study should be affected as little as possible. Undesired disintegration of production casing and heat induced cracks in annulus cement could be the result from this approach, and should be investigated further. In addition, metal disintegration is a time consuming operation, and with a steel removal rate of 84 kg/h the tool will have to operate several days to remove the required sections. As plasma milling produce cuttings which are meant to drop into a sump or rat-hole, the volume of such sump should be estimated. A-1 estimates are available in Appendix F. The porosity of both the disintegrated material and the porosity of the cuttings bed are conservative estimates, and needs to be further researched. Calculations show that the cuttings bed height is a factor to be taken into account. In operations with a limited impermeable formation interval for plug setting, cuttings may have to be removed. The preferred solution would be to circulate out most of these cuttings to be able to set cement plugs at desired depth. Lift calculations should be made with more accurate input data to check the possibility to lift cuttings using CT and normal circulation. The wiper method could be a possibility if simulations show it is possible. Reverse circulation using CT could also be a solution, but NORSOK (2013b) specifies that the CT shall include check valves. Venturi baskets or bailers are also possibilities, but time consuming considering the calculated cuttings volumes.

Cement evaluation. The tubing hanger and tubing leaves a major restriction that the tools need to pass before entering the logging interval. In A-1, these tools need to pass the DHSV ID of 4.56”. In addition to limiting the choice of desired ultrasonic bond tool rotating head, the key challenge is tool centralization. The lower density well fluid will somewhat compensate for the smaller rotating head chosen to pass the tubing. Associated centralizers, on the other hand, are not meant to pass restrictions smaller than the ID to be logged. More rigid centralizers will hinder the tools while running in through the tubing, and weaker centralizers will affect centralization once the casing to be logged is reached. Jobs have been performed running through 7” tubing to log 9-5/8” casing, but tubing sizes of 5-1/2” and smaller could be a challenge.

Alternative tools, like the Segmented Bond Tool (SBT), are available and would not have the same issues with regards to centralization and rotating head OD. SBT might not give as accurate log results with regards to cement channeling, but could be a viable alternative in TT P&A applications. The SBT has a 3-3/8” OD and will log casing size in range of 4-1/2” to 13-3/8” with same tool setup.

An alternative to cement logging could be to perforate and pressure test in steps. Coiled tubing with two packers could be used for this purpose, although not presented in this thesis. Another solution could be to run the thermite plug in the interval, creating a cross-sectional barrier without the need of annular WBE.

Cement barrier and formation definitions. As listed in Table 1.3, a single cement barrier needs to be minimum 100m unless set on a mechanical/cement plug. In the case study an inflatable plug is considered a tested mechanical plug. An alternative to the inflatable plug could be either a shorter cement interval, or possibly a thermite plug to act as a base. A continuous (back-to-back) plug is not regarded a possibility on this rigless approach as it needs to be drilled to hard cement for verification (NORSOK D-010 2013a). A CT drilling motor (PDM) could be an option, but drilling cuttings will have to be managed. The relatively low circulation rates of CT and large casing ID will make hole cleaning difficult. Drilling debris collection at depth could be an alternative, although not presented in this thesis.

In the rigless approach to P&A A-1, OBF#1 and the reservoir are regarded as one reservoir. According to NORSOK D-010 (2013a), two reservoirs in the same pressure regime could be regarded as one. In case of pressure differences, a cross flow barrier shall be set. Depending on these definitions, A-1 could be plugged with two, three or four cement plugs. The least time consuming would be to set primary and secondary cement plug above overburden formation #1, as done in the case study.

Surface equipment. Although stated that this thesis would not look into the surface equipment issue of a rigless approach to P&A, some aspects are worth mentioning. The suggested approach would need a wireline package in addition to CT unit and cementing pump and pits. The proposed step list includes a lot of rigging back and forth between the different technologies, as clarified in detailed step list in Appendix F. A more streamlined surface setup would make the proposed solution more efficient. In addition to deck space, accommodation for well intervention crew must be considered. On bigger NCS platforms this might not be an issue at all, but on smaller wellhead platforms it could be factor to take into account. Shuttling personnel to and from these wellhead platforms/normally unmanned installations (NUI) will result in a lower operational efficiency compared to platforms with accommodation.

4.2 Plug and abandonment of well A-2

The well was shut in and plugged as part of a batch P&A operation. The well schematic is presented in Figure 4.5 and summarized in Table 4.3. As the data package received on A-2 was incomplete, some of the well data is estimated while other data is collected from the Norwegian Petroleum Directorate (NPD) fact page for the relevant field (NPD 2017).

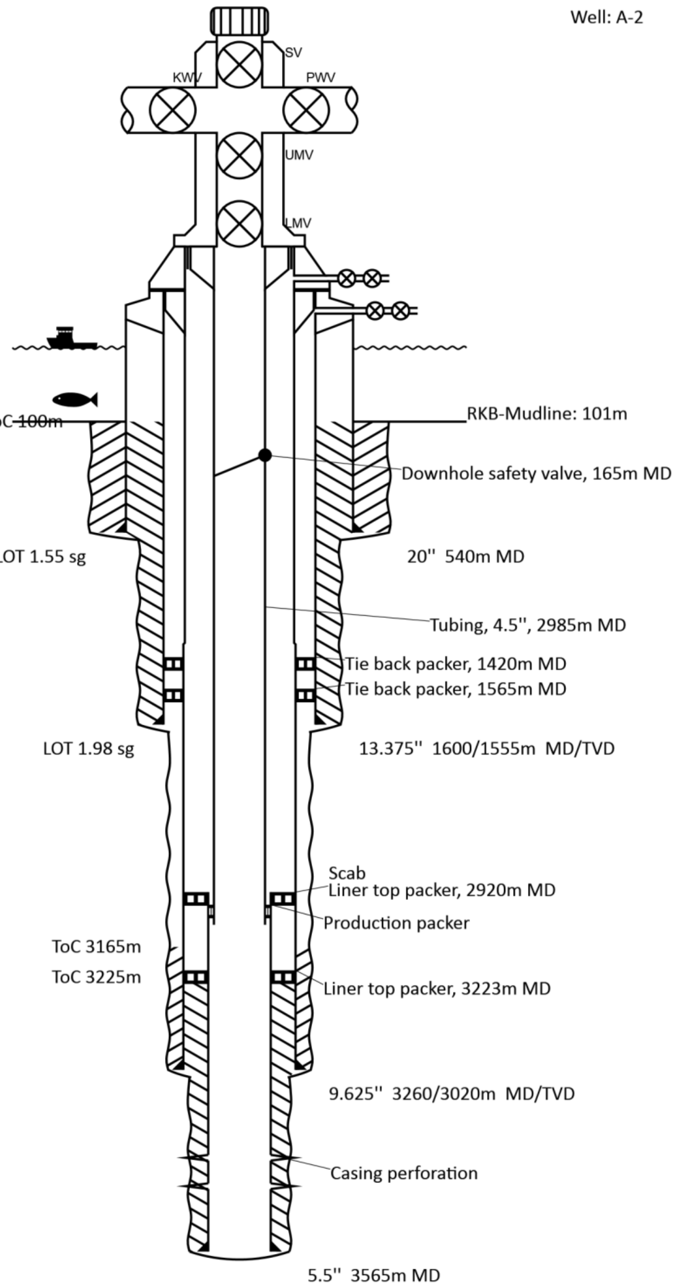


Figure 4.5: Well schematic A-2. Produced with Wellbarrier software.

Table 4.3: A-2 Well summary table

Description		Depth
13-3/8" csg.	Shoe @	1600m / 1555mTVD
	TOC @	wellhead
9-5/8" csg	Shoe @	3260m / 3020mTVD
	TOC @	3165m
5-1/2" Liner	Hanger @	2920m
	Shoe @	3565m
	TOC @	2920m
4-1/2" prod. tubing	DHSV @	165m
	Prod. Packer @	2960m
	WEG	2985m
Reservoir	top @	3265m /3030mTVD
Perforation interval		3290 - 3510m
Formation (Fm) with potential in overburden.	Fm top @	
OBF #1		1765mTVD
Estimation of minimum setting depth based on:		
Gas density	0.23 s.g	Overburden
Oil density	0.662 s.g	Reservoir
LOT	1.98 s.g	1555mTVD
Estimated formation strength	1.86 s.g	3020mTVD

Data in minimum setting depth Table 4.4 have been extracted from gradient curves showing pore- and fracture pressure. The presented depths are estimated using oil gradient for reservoir and gas gradient for OBF#1.

Table 4.4: A-2 Pore pressure and fracture pressures given in equivalent mud weight. Minimum setting depth calculated, as for A-1, and given in table.

Formation	*Depth*	*Pore pressure*	*Fracture pressure*	*Minimum setting depth*
Reservoir	3030 mTVD	1.67 sg	1.86 sg	2550 mTVD
OBF #1	1765 mTVD	1.65 sg	1.86 sg	1538 mTVD

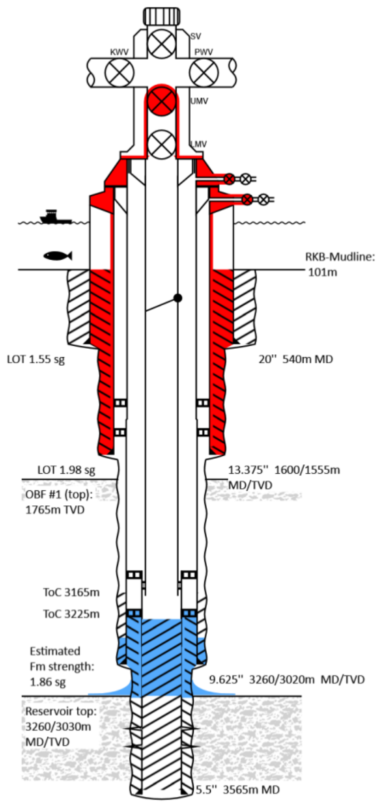
Well status pre-P&A:

- Perforations squeezed by bullheading cement through tubing. Cement plug tested and qualified as temporary primary barrier.
- Displacement fluid from cement squeeze in tubing
- Completion fluid in annulus-A
- WL retrievable downhole safety valve installed.
- Reservoir temperature estimate: 133°C
- Reservoir virgin pressure: 483 bar
- Sustained casing pressure observed in annulus-B, between 13-3/8” and 9-5/8” csg.

The well status is illustrated in the WBS in Figure 4.6.

Universitetet i Stavanger

Field : Wittberg	Well design pressure 690 Bar
Well : A-2	Reservoir pressure 482 Bar
Schematic : US.P 5.6-a1 rev.1	Prepared By : Stian Wittberg
Date : 18.May.2017	Verified By :



Depth reference is Unspecified reference

Prepared by Universities

Temporary abandonment

Temporary plug

Draft

Primary barrier elements

Element	Qualification	Monitoring
Liner top packer	Pressure test to 345 bar	A-annulus pressure
Cement plug	Pressure test to 180 bar	Pressure above plug
Production liner	Pressure test to 345 bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production liner cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Suspension x-mas tree	Pressure test to 690 bar	Pressure tested to 345 bar
Spool wellhead A with access valve	Pressure test to 345 bar	External observation
Spool wellhead	Pressure test to 345 bar	External observation
Production casing	Pressure test to 345 bar	B-annulus pressure
Surface casing	Pressure test to 345 bar	B-annulus pressure
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure

Healthy well, no or minor issue

Note:

Initial qualification test pressures not available in data package. All pressures estimated based on relevant EAC and given data.

Figure 4.6: WBS for status of A-2 prior to P&A operation. Produced using Wellbarrier software.

4.2.1 Conventional approach to P&A A-2

Similar to A-1, A-2 was part of a batch P&A and preparation for rig activities were done by a stand-alone wireline operation. The pre-P&A phase includes the following steps:

- Rig up wireline equipment
- Pull DHSV
- Drift well to hold up depth (HUD)
- Punch hole in tubing for tubing cutter
- Cut tubing in area above production packer/below scab liner hanger.
- Set shallow bridge plug with "pump open" sub in area below wellhead.
- Rig down wireline equipment
- Displace well to kill mud

The well is at this stage secured, and barriers are in place for nippling. A jack-up rig is used for the remaining operation, including P&A phase one and two.

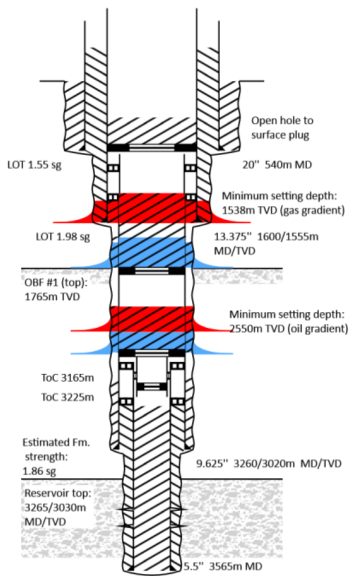
- Skid rig. Nipple down XT, nipple up and test drilling BOP
- Retrieve tubing down to P&A depth
- Run ultrasonic cement bond log including MFC
    - Confirming no cement above scab liner top packer
    - No creeping formation found in overburden
- Clean out run in 9-5/8" csg. Clean plug setting area.
- Set a 100m continuous (back-to-back) cement plug, using PWC, to act as primary and secondary barrier for reservoir.
    - Set on top of tested mechanical base
- Dress off and tag cement. Pressure test plug to LOT + 70 bar.
- Set 50 m cement plug using PWC, to act as primary barrier for OBF #1.
    - Set on top of tested mechanical bridge plug
- Tag and pressure test cement plug to LOT + 70 bar.
- Set secondary cement plug in 13-3/8" shoe area using PWC.
    - Ref. minimum setting depth 1538m TVD for secondary intermediate barrier.
- Tag and pressure test cement plug to LOT + 70 bar.
- Cut and pull 9-5/8" casing from required surface plug depth.
- Set surface cement plug.
    - Set on top of tested mechanical bridge plug.
- Tag and pressure test cement plug to LOT + 35 bar.

The above sequence places two primary and secondary barriers in a well with missing annular barrier elements in plug setting area. Status after the operation is illustrated in WBS Figure 4.7.

Universitetet i Stavanger

Field : Wittberg
Well : A-2
Schematic : US.P 5.7-a1 rev.1
Date : 18.May.2017

Well design pressure 690 Bar
Reservoir pressure 482 Bar
Prepared By : Stian Wittberg
Verified By :



Depth reference is Unspecified reference

Prepared by Universities

Permanent abandonment

Jack up rig P&A operation

Draft

Primary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:

Figure 4.7: WBS of A-2 after jack-up rig plugging operation. Produced using Wellbarrier software.

4.2.2 Rigless approach to P&A A-2 using emerging technologies

On first review this well looks as a complex plugging operation and might not be a rigless candidate. A-2 does not have the desired 9-5/8" TOC in sufficient height above production packer. In A-1 this annular cement was used as a well barrier element for the reservoir plugs. The lack of this WBE will make a rigless operation more challenging. The aim of this rigless approach is to stay in a cased hole environment, but A-2 is a typical section mill/PWC candidate to create a rock-to-rock barrier. Lowry and Dunn (2016) proposed a diluted thermite mixture to swage the casing outwards into the un-cemented annulus, in combination with setting a thermite plug internally in the casing. The amount of thermite needed for compliance with NORSOK D-010 (2013a) results in the rigless approach presented below. A more practical use of thermite for well plugging is presented in section 4.2.2.1, although not NORSOK D-010 (2013a) compliant. The status prior to P&A will be same as for the conventional approach. The surface equipment needed for the rigless approach will be the same as A-1, and all operations are performed using CT or WL.

Operational step list for rigless TT P&A approach on A-2:

A more detailed step list and calculations performed are attached in Appendix H

1) Rig up wireline
2) Drift well for plasma bit
3) Punch tubing above production packer.
4) Displace well to seawater
5) Disintegrate tubing using plasma bit. Remove minimum 100m tubing above scab liner top packer.
6) Set inflatable plug and heat insulating material above scab liner packer in 9-5/8" csg. Pressure test plug.
7) Place diluted thermite to swage casing into formation and create a 50m cross-sectional primary reservoir barrier.
8) Tag plug and pressure test primary thermite plug to LOT + 70 bar.
9) Place diluted thermite to create a 50m cross-sectional secondary reservoir barrier.
10) Tag plug and pressure test secondary thermite plug to LOT + 70 bar.
11) Disintegrate minimum 100m of tubing in area above OBF #1.
12) Set and pressure test an inflatable plug with heat isolating material to act as base for thermite mixture.
13) Place diluted thermite to swage casing into formation and create a 50m cross-sectional primary intermediate barrier.
14) Tag plug and pressure test to LOT + 70 bar.

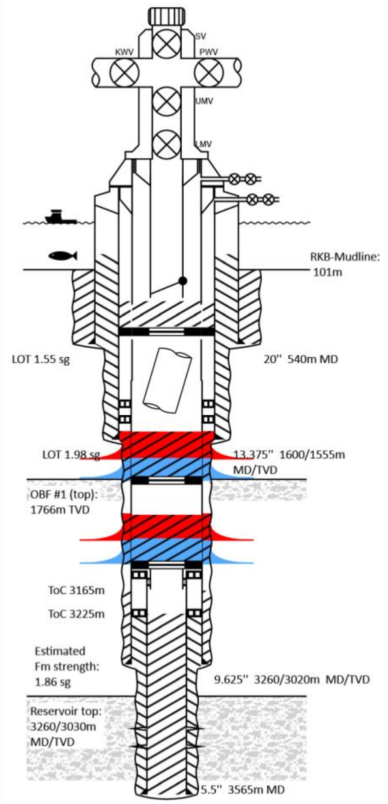
15) Place diluted thermite to swage casing into formation and create a 50m cross-sectional secondary intermediate barrier
16) Tag plug and pressure test to LOT + 70 bar
17) Disintegrate minimum 50m of tubing using plasma bit in area above 20” csg. shoe.
18) Disintegrate 9-5/8” production casing in same area using plasma bit.
19) Set and pressure test an inflatable plug with heat insulating material to act as base for thermite mixture.
20) Place thermite to create a 50m cross-sectional barrier in 13 3/8” casing. This will act as open hole to surface barrier.
21) Tag plug and pressure test to LOT + 35 bar
22) Rig down equipment

Figure 4.8 illustrates the well barrier status after the rigless P&A approach listed above.

Universitetet i Stavanger

Field : Wittberg
Well : A-2
Schematic : US.P 5.7-a2 rev.1
Date : 18.May.2017

Well design pressure 690 Bar
Reservoir pressure 482 Bar
Prepared By : Stian Wittberg
Verified By :



Permanent abandonment

Rigless P&A

Draft

Primary barrier elements

Element	Qualification	Monitoring
Thermite plug	Pressure test to 198 bar	Pressure above plug
Thermite plug	Pressure test to 292 bar	Pressure above plug
N/A	N/A	N/A
N/A	N/A	N/A
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Thermite plug	Pressure test to 198 bar	Pressure above plug
Thermite plug	Pressure test to 292 bar	Pressure above plug
N/A	N/A	N/A
Casing cement	N/A	N/A
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:
N/A lines due to illustrative purposes.

Depth reference is Unspecified reference

Prepared by Universities

Figure 4.8: WBS of A-2 after rigless P&A operation. Produced using Wellbarrier software.

4.2.2.1 Discussion on rigless approach to P&A A-2

Some aspects of the operation and possible challenges are further discussed below.

Diluted thermite to swage casing. The concept of using thermite to plastify the casing, making it extend radially and swage against the borehole wall, was presented by Lowry and Dunn (2016). No research has been published on the matter, and it could perhaps not be possible at all. The production casing annulus would most likely consist of settled mud at the desired depth, and the proposed swaging operation might not be needed. Verifying settled material in this annular space by logging would be difficult due to the small tubing ID.

Assuming that swaging the casing using thermite is not possible, and that the casing will be in a molten state after thermite initiation, then creation of a cross-sectional barrier can be difficult. Internally in the casing the thermite mixture is set on top of a plug with a heat insulating material placed between the plug and thermite, as illustrated in Figure 3.16. This plug will act as a base and will not be affected by the thermite reaction heat. If the un-cemented casing is molten and not plastified then the molten plug material might be displaced to a lower depth in the annulus. This displacement may occur due to the lower density annular fluid in the un-cemented void space and the higher density molten thermite mixture. The desired cross-sectional barrier interval would not be achieved if such a displacement occurs.

A fluid filled annulus might not be as great a challenge as assumed in this thesis, and should be investigated further. This investigation might also provide some answers to whether it will be possible to place thermite directly in the tubing, creating a cross-sectional formation to formation barrier (with a fluid filled annulus A and B).

Thermite placement. In the above sequence, thermite placement is proposed done by circulating, as presented by Skjold (2013). Both companies researching thermite plugs are planning for WL conveyed thermite placement. When setting barriers according to current NORSOK (2013a) regulations it would lead to several dozen runs, as briefly estimated in Chapter 3. If circulation is a viable solution for thermite placement then the plasma milled section might be redundant. A possibility could be to circulate the slurry through big hole perforations in tubing thereby placing the thermite slurry in the annulus-A and tubing, much like a PWC operation. The total concept of pumping thermite must be thoroughly researched with risk in mind. An un-intended ignition of thermite in pumps etc. could be catastrophic. By conveying thermite by WL in a concealed container, ignition will be easier to control.

Supercritical fluids due to thermite combustion heat. As described in Chapter 3 well fluids in close vicinity of the thermite reaction will reach a supercritical state on typical NCS reservoir barrier depths. Tests have been performed in a test cell to simulate well conditions, as described in section 3.2.3, but these results have not been published. The effect of igniting thermite downhole should be investigated further to identify if the superheated vapour will reach surface, and how to deal with it.

Thermite plug height. The requirement of placing nearly $7m^3$ of thermite to create a total of 100m primary and secondary reservoir barrier seems excessive. The product of a thermite reaction, when diluted, has favorable sealing properties, as presented in Chapter 3. Further research and tests should be done on sealability, and with favorable results the NORSOK D-010 (2013a) height specifications can be challenged. This also seems to be the approach chosen by the R&D company developing the thermite P&A plug. A reduced plug height will make the intended WL conveyance approach more viable.

Rigless P&A of A-2. As mentioned above, A-2 might not be the optimum candidate for a rigless P&A approach. The well design makes P&A a complex operation. An option could be to perform phase 1, reservoir abandonment, using a rigless approach. The intermediate plugging operations, phase 2, would be performed by a rig. By doing these operations in batches, the rig scope could be reduced significantly. An alternative WBS showing status after reservoir P&A of A-2 using thermite plugs conveyed by WL are presented in Figure 4.9. The approach illustrated in the figure assumes thermite plug height requirements less than 50 m in future NORSOK D-010 (2013a) revisions. A step list of this approach is presented in Appendix I.

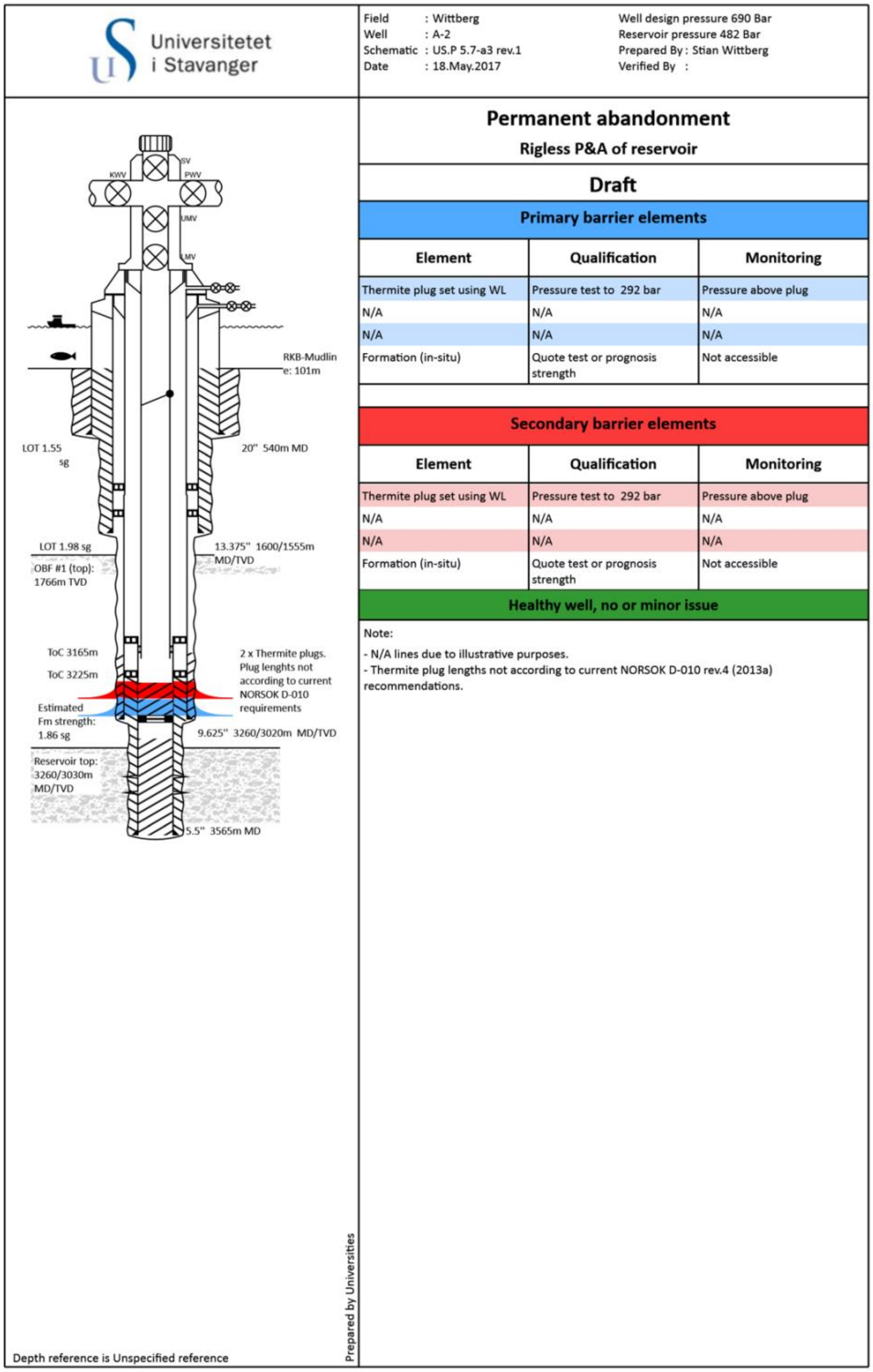


Figure 4.9: Rigless approach to plug reservoir using thermite plug set on WL. Assuming thermite plug length requirement will be less than for cement in future NORSOK D-010 (2013a) revisions. Produced using *Wellbarrier* software.

4.3 Plug and abandonment of well A-3

The well was initially completed as a horizontal oil producer, and shut-in to be part of a batch P&A operation. The well schematic is presented in Figure 4.10 and summarized in Table 4.5. A-3 has a complex overburden with several formations to be sealed off during P&A. The overburden formations (OBF) that have a potential to flow and/or are water/hydrocarbon (HC) bearing have been given numbers, for a more systematic approach.

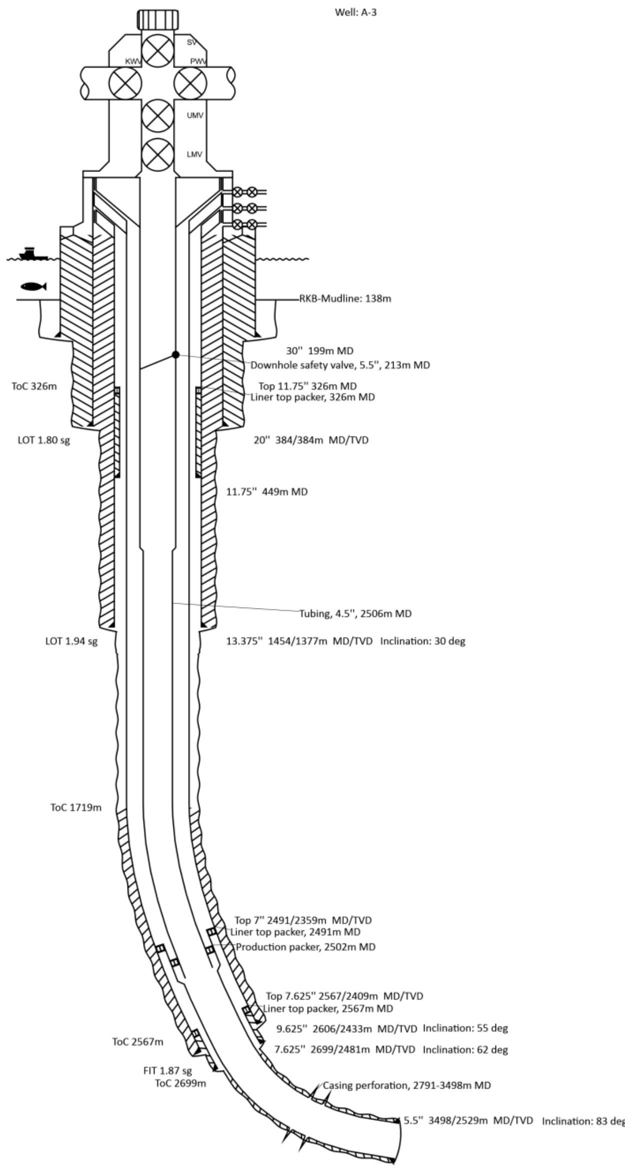


Figure 4.10: Well schematic of A-3. Produced with *Wellbarrier* software.

Table 4.5: A-3 well summary table

Description		Depth
20" csg.	Shoe @	384m
	TOC @	wellhead
13-3/8" csg.	Shoe @	1454m / 1377mTVD
	TOC @	wellhead
9-5/8" csg	Shoe @	2606m / 2433mTVD
	TOC @	2106m
7-5/8" Liner	Hanger @	2567m / 2409mTVD
	Shoe @	2699m / 2481mTVD
	TOC @	2567m
7" x 5-1/2" Liner	Hanger @	2491m / 2359mTVD
	Shoe @	3498m / 2529mTVD
	TOC @	2700m
5-1/2" x 4-1/2" prod. tubing	DHSV @	213m
	X-Over @	631m
	Prod. Packer @	2502m
	WEG	2506m
Reservoir	top @	2699m / 2481mTVD
Perforation interval		2805m - 3413m
Formations (Fm) with potential in overburden.		
OBF #1	Fm top @	2288m / 2188mTVD
OBF #2	Fm top @	1529m / 1444mTVD
OBF #3	Fm top @	946m / 929mTVD
Formations (Fm) with normal pressure.		
OBF #4	Fm top @	697m / 692mTVD
OBF #5	Fm top @	539m / 538mTVD
OBF #6	Fm top @	494m / 493mTVD
OBF #7	Fm top @	424m / 424mTVD
Formation (Fm) without potential, but water bearing.		
OBF # 8	Fm top @	224m / 224mTVD
Estimation of minimum setting depth based on:		
Gas density	0.16 s.g	
Oil density	0.67 s.g	
LOT @ 20" shoe	1.80 s.g	384mTVD
LOT @ 13-3/8" shoe	1.94 s.g	1377mTVD
FIT @ 9-5/8" shoe	1.87 s.g	2433mTVD

Minimum setting depth estimated based on pore- and fracture pressure given for the overburden formation, using gas density. Results are presented in Table 4.6.

Table 4.6: A-3 Pore pressure and fracture pressures given in equivalent mud weight. Minimum setting depth calculated, as for A-1, and given in table.

Formation	*Depth*	*Pore pressure*	*Fracture pressure*	*Minimum setting depth*
Reservoir	2481 mTVD	1.70 sg	1.90 sg	2196 mTVD
OBF #1	2188 mTVD	1.58 sg	1.90 sg	1786 mTVD
OBF #2	1444 mTVD	1.68 sg	1.90 sg	1262 mTVD
OBF #3	929 mTVD	1.06 sg	1.90 sg	480 mTVD

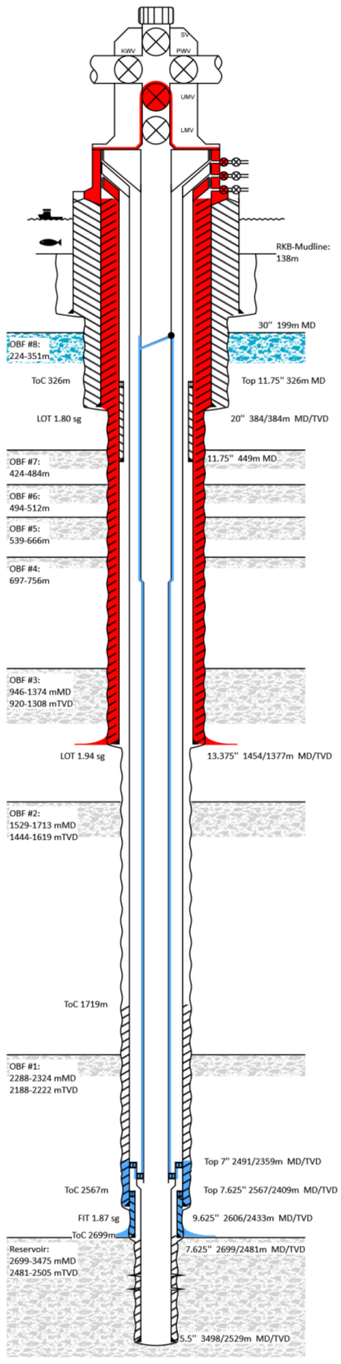
Well status pre-P&A:

- Oil/water/gas in tubing
- Completion fluid in annulus-A
- DHSV tested OK
- Reservoir temperature: 92°C
- Reservoir pressure: 414 bar
- Sustained casing pressure observed in annulus-B, between 13-3/8" and 9-5/8" csg.
- Injectivity test performed OK

The well status is illustrated in WBS, Figure 4.11.

Universitetet i Stavanger

Field : Wittberg	Well design pressure 450 Bar
Well : A-3	Reservoir pressure 414 Bar
Schematic : US.P 4.1-a2 rev.1	Prepared By : Stian Wittberg
Date : 16.May.2017	Verified By :



Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

Producer

Production

Draft

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test to 70 bar	Tubing pressure
Tubing	Pressure test to 375 bar	A-annulus pressure
Production packer	Pressure test to 375 bar differential	A-annulus pressure
Liner top packer	Pressure test to 375 bar differential	A-annulus pressure
Liner top packer	Pressure test to 375 bar differential	A-annulus pressure
Production liner	Pressure test to 375 bar differential	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Drilling liner cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Suspension x-mas tree	Pressure test to 450 bar	Pressure tested to xxx bar
Wellhead annulus access valve	Pressure test to 375 bar	Periodic pressure testing
Wellhead	Pressure test to 375 bar	External observation
Casing hanger	Pressure test to 375 bar	A-annulus pressure
Intermediate casing	Pressure test to 375 bar	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:

Initial qualification tests for well components not available in data package. All pressures are estimated using reservoir pressure and gas gradient.

Figure 4.11: WBS of A-3 prior to P&A operation. Produced with Wellbarrier software.

4.3.1 Conventional approach to P&A A-3

Similar to the two previous wells A-3 was part of a batch P&A campaign. The pre-P&A phase were done as a stand-alone well intervention operation, using CT and wireline. The pre-P&A phase include the following steps:

- Rig up CT unit
- Drift well to plug setting depth.
- Run MFC including pressure and temperature logs.
- Set cement plug above perforations using CT.
- Tag and inflow/pressure test cement plug.
- Cut tubing above production packer.
- Displace well to brine through tubing cut.
- Lock open/set wear sleeve in DHSV
- Set shallow "pump open" bridge plug above DHSV and pressure test same.
- Rig down equipment
- Displace well to kill mud

The well is at this stage secured, with barriers in place for nippling. A jack-up rig is used for the remaining P&A operations:

- Skid rig, nipple down XT, nipple up BOP and pressure test.
- Retrieve tubing down to P&A depth
- Clean out run in 9-5/8" casing. Clean out plug setting area.
- Run ultrasonic cement bond log in 9-5/8" casing.
    - Confirm TOC.
    - Check for creeping shale above cement.
- Set a continuous (back-to-back) plug to act as primary and secondary barrier for reservoir and OBF #1. TOC plug to be 100m above OBF #1.
    - Set on tested mechanical base
- Dress off, tag and verify cement plug by pressure test
- Set a continuous cement plug using PWC to act as primary and secondary barrier for OBF #2. TOC plug to be 100m above OBF #2.
    - Set on tested mechanical base.
- Dress off, tag and verify cement plug by pressure test
- Cut and pull 9-5/8" casing from top of OBF #3 depth.
- Clean out run in 13-3/8" casing. Clean out plug setting area.
- Run ultrasonic cement bond log in 13-3/8" casing.

- Set a continuous cement plug to act as primary and secondary barrier for OBF # 3
    - Set on top of a tested mechanical base.
- Dress off, tag and verify cement by pressure test
- Set a continuous cement plug to act as primary and secondary barrier for OBF # 4,#5,#6 and #7
    - Set on top of a tested mechanical base.
- Dress off, tag and verify cement by pressure test
- Recover 13-3/8” csg from top of OBF #8 depth.
- Clean out 20” csg
- Run ultrasonic cement bond log in 20” casing.
- Set surface cement plug and test same
    - Set on top of tested mechanical base

The above sequence places four primary and secondary barriers in a well where one of the OBF was missing an annular barrier element. The plugs are acting as barriers for the reservoir and 8 overburden formations.

Status after the above P&A operation is illustrated in WBS Figure 4.12.

Universitetet i Stavanger

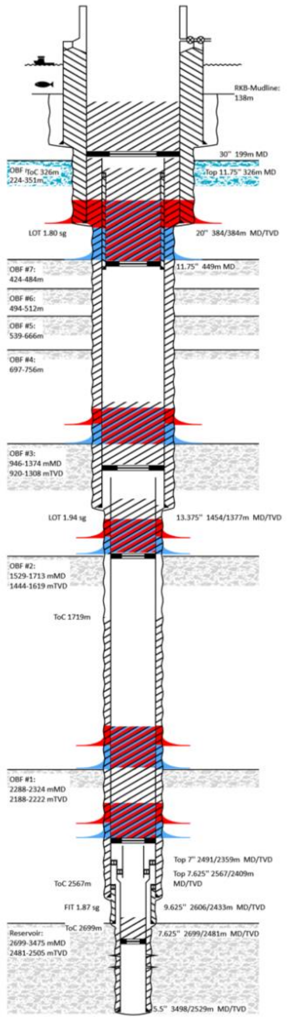
Field : Wittberg
Well : A-3
Schematic : US.P 5.7-a1 rev.1
Date : 18.May.2017

Well design pressure 450 Bar
Reservoir pressure 414 Bar
Prepared By : Stian Wittberg
Verified By :

Permanent abandonment

Jack up rig P&A

Draft



Primary barrier elements

Element	Qualification	Monitoring
Reservoir Cement plug	Pressure test to 100 bar	Pressure above plug
OBF#2 Cement plug	Pressure test to 97 bar	Pressure above plug
OBF#3 Cement plug	Pressure test to 83 bar	Pressure above plug
OBF#7 Cement plug	Pressure test to 83 bar	Pressure above plug
OBF#1 Cement plug	Pressure test to 100 bar	Pressure above plug
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Drilling liner cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Reservoir Cement plug	Pressure test to 100 bar	Pressure above plug
OBF #2 Cement plug	Pressure test to 97 bar	Pressure above plug
OBF #3 Cement plug	Pressure test to 83 bar	Pressure above plug
OBF #7 Cement plug	Pressure test to 83 bar	Pressure above plug
OBF #1 Cement plug	Pressure test to 100 bar	Pressure above plug
Surface casing cement	Formation test, job performance or bond log	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Drilling liner cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:

Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

Figure 4.12: WBS of A-3 after jack-up rig plugging operation. Produced using Wellbarrier software.

4.3.2 Rigless approach to P&A A-3 using emerging technologies

A-3 has a complex overburden with several formations to be sealed off. The overburden formation #2 is in an area where 9-5/8" casing is un-cemented, leading to the need of PWC or section milling in conventional rig P&A. In addition it is completed with a 5.5" x 4.5" tubing. The small ID of a 4.5" tubing could make annular barrier verification a challenge in all rigless TT P&A. Similar to A-2, this well would not be the optimum candidate for a fully rigless P&A approach due to its small tubing, lack of annular barrier for OBF#2 and its complex overburden. For the purpose of the thesis, a partial rigless P&A approach is presented below. As ultrasonic cement logging tools presently available will not pass the tubing restrictions of this well, a segmented bond tool (SBT) is assumed to provide sufficient log quality for the annular barrier verification. The approach is chosen to demonstrate diversity between the three case studies. The below step list could be regarded as an alternative pre-P&A operational approach. All operations in the sequence are performed using wireline or coiled tubing.

Operational step list for a partial rigless TT P&A approach on A-3:

A more detailed step list and calculations performed are attached in Appendix K.

1) Rig up CT unit
2) Drift well to top of perforations.
3) Set cement plug from top perforations to top of reservoir. Set on cement retainer.
4) Tag cement plug, pressure and inflow test.
5) Disintegrate minimum 50m of 5-1/2" Liner using Plasma bit to expose the 7-5/8" cemented liner.
6) Log 7-5/8" Liner cement using SBT
7) Set an inflatable plug to act as base for cement plug, and test same.
8) Set 50m cement plug in 7-5/8" liner to act as primary barrier for reservoir
9) Tag and pressure test barrier plug
10) Disintegrate minimum 50m of 5-1/2" liner in area below tubing WEG to expose 9-5/8" cemented production casing.
11) Clean out plasma bit cuttings bed to gain 50m plug setting interval.
12) Log 9-5/8" casing cement in plug setting interval using SBT
13) Set inflatable plug to act as base for cement plug, test same.
14) Set 50m cement plug in 9-5/8" csg. to act as secondary barrier for reservoir.
15) Tag and pressure test secondary barrier plug
16) Disintegrate minimum 100m tubing using plasma bit in area above OBF #1.
17) Log 9-5/8" csg. cement in same area using SBT
18) Set inflatable plug to act as base for cement plug, test same.

19) Set 50m cement plug to act as primary barrier for OBF #1
20) Tag and pressure test primary barrier plug
21) Set 50m cement plug to act as secondary plug for OBF #1
22) Tag and pressure test secondary barrier plug
23) Set hold open/wear sleeve in DHSV
24) Set shallow "pump-open" bridge plug and pressure test same
25) Rig down equipment
26) Displace well to kill mud.

The well status after the proposed rigless P&A operations is presented in Figure 4.13. The well is secured and ready for nippling. After BOP installation a rig could pull tubing and continue the plugging operation from OBF #2 and upwards.

4.3.2.1 Discussion on rigless approach to P&A A-3

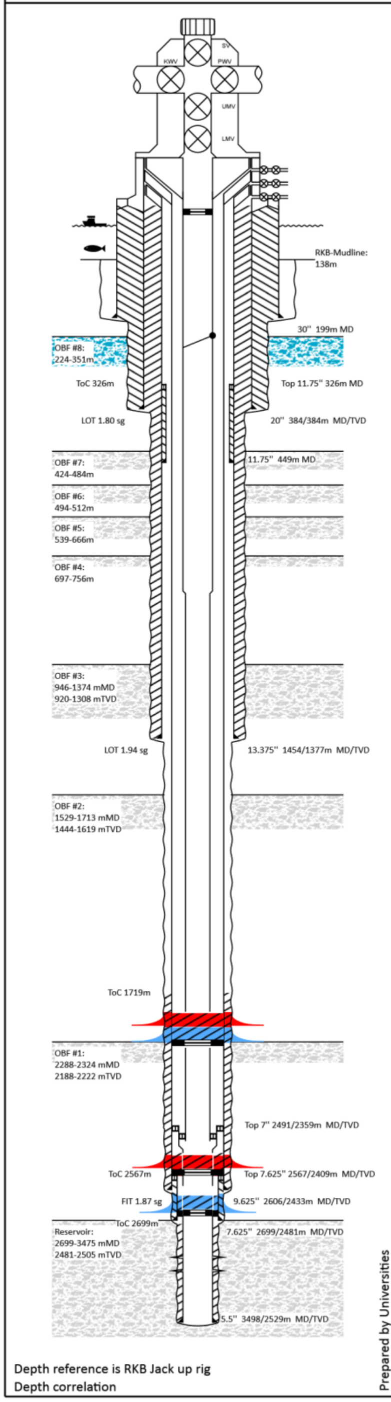
Some aspects of the operation and possible challenges are further discussed below.

Rigless batch P&A. The proposed solution would save several rig-days. For A-3 nearly 5.5 days were estimated to clean out and log 9-5/8" csg and installing reservoir and OBF #1 barriers. Assuming a CT unit cost to be a fifth of rig rate, the above rigless sequence should be completed within twenty-seven days to be competitive. The main time consuming activities in the proposed rigless P&A would be to change CT reels back and forth, as the plasma bit uses a special umbilical CT, while other applications use conventional CT.

Cement evaluation tools. As discussed for A-1, some compromises might have to be made with regards to cement bond logging data. The 4.5" tubing (4.5" 15.2ppf: 3.826" ID) could result in the desired size ultrasonic rotating head not passing the restrictions. To run two different logging tools in combination, ultrasonic azimuthal bond log and CBL/VDL, is often done to confirm the bonding results and gain confidence in the annular barrier quality. In rigless P&A operations run through small tubing, the ultrasonic rotating head might have to be deleted from the string. According to NORSOK D-010 (2013a) *"The measurement shall provide azimuthal/segmented data"*. This means that the SBT can be used as an alternative to the ultrasonic tool. Only creeping formation WBE qualification requires two independent tools where azimuthal log is specified as one of them.

Universitetet i Stavanger

Field	: Wittberg	Well design pressure 450 Bar	
Well	: A-3	Reservoir pressure 414 Bar	
Schematic	: US.P 4.1-a2 rev.1	Prepared By : Stian Wittberg	
Date	: 16.May.2017	Verified By :	



Producer

Production

Draft

Primary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Drilling liner cement	Formation test, job performance or bond log	B-annulus pressure
N/A	N/A	N/A
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Cement plug	Pressure test to LOT + 70 bar	Pressure above plug
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
N/A	N/A	N/A
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:
N/A lines due to illustration purposes.

Figure 4.13: WBS of A-3 after rigless P&A of reservoir and OBF #1. Produced using Wellbarrier software.

5. Results and Discussion

Several challenges with the rigless P&A approach using emerging high-energy technologies have been discussed in the case studies. These challenges will also be discussed briefly in this section, in addition to other aspects of the rigless P&A approach to provide an overall picture.

5.1 Electric plasma miller

Metal disintegration. The tool is in the research and development (R&D) stage. Field trials have not been performed, and it is therefore difficult to identify all the possible challenges. The A-1 case study well was plugged using a plasma miller to remove tubing and gain access to the cemented casing. The company developing the Plasma Bit appears to be aiming for a different approach than that proposed in the case study. Their approach includes removing both the tubing and the casing with the associated cement to gain access to formation, much like a conventional section mill (Gajdos et al. 2015; Gajdos et al. 2016). The alternative method presented in this thesis will have to be further researched before concluded viable. Casing and cement integrity after exposure to heat from the plasma miller will be an important issue to be clarified. In addition, its ability to remove control lines and larger completion components, such as side pocket mandrels should be investigated.

Through tubing cement bond logging. One of the key elements in the proposed approach is the ability to run cement logging tools through tubing. These logging tools are designed to run directly in casing, not to pass a tubing ID before reaching the intended logging interval. Preferred centralizers for these tools are rigid slip-over centralizers, while through tubing conveyance would require softer in-line centralizers. In-line centralizers could have trouble centralizing the tools in highly deviated sections. In addition the preferred size azimuthal ultrasonic rotating head for 9-5/8" csg. will not pass tubing of 5-1/2" and smaller. Alternative tools are available and selection will be dependent on well configuration and logging data requirement.

Surface equipment. An aspect of the proposed approach that may not be highlighted in the case study is the surface equipment and changeover between WL, CT and plasma miller. The Plasma Bit requires a purpose built CT-reel conveyed umbilical, while other operations utilize WL or conventional CT. Changing reels back and forth, or setting up both reels for simultaneous operation could impose challenges. Deck space and deck load capacity should be investigated in a feasibility study for the specific platform, while crane and weather also must be taken into account during operation. Smaller wellhead platforms, or "normally unmanned installations" (NUI), with limited deck space and no accommodation would lead to an ineffective operation. Personnel would need shuttling or temporary accommodation. Equipment might have to be rigged down, and removed to clear deck space, before rigging up new equipment for next step in the operation.

Plasma Bit cuttings. Disintegrating tubing, using Plasma Bit, produces high porosity cuttings. The cuttings are intended to drop into a sump (rat-hole) below the plug setting area. Not all well configurations will allow a large enough rat-hole, as seen in A-3. This would also be an issue in A-1, depending on the two lower zones defined as one or two reservoirs. If defined as two reservoirs, then three or four cement plugs should to be set, and the cuttings height would push plug setting depth shallower than desired. Estimations done in the case study show it is a factor to take into account. Disintegrating one meter of 5-1/2" tubing inside a 9-5/8" csg will produce a 0.4m high cuttings bed, given the estimated porosities. As each meter removed tubing will leave only 60 cm of exposed casing for plug setting, cuttings removal should be evaluated. Further research on the cuttings matrix porosity/density and the possibility to circulate out and clean rat-hole area should be done.

Cement plug verification. Setting permanent P&A cement plugs and verifying them is conventionally done by drill pipe on the NCS. NORSOK D-010 (2013a) reflects this, as tagging and drilling to hard cement are common methods for verification. Setting a continuous (back-to-back) plug was not regarded an option during the rigless approach proposed. Such a plug must be drilled to hard cement for verification, and hole cleaning could be an issue in a mud-less well environment using CT. Verification by tagging is not further specified in NORSOK D-010 (2013a). Setting down weight on drill pipe can provide significantly more tagging force than when tagging with CT or WL. Tagging with CT was considered sufficient during the case studies, although the plugs were also pressure tested.

5.2 Thermite plug

Plugging material placement. Placing enough thermite to comply with NORSOK D-010 (2013a) plug height requirements could be a challenge. Both R&D companies are aiming for a WL conveyed plug placement technique. The R&D company developing a thermite plug for P&A purposes is promoting it as an option where no tubing removal is required. Not removing the tubing before igniting the thermite could compromise its ability to create a cross-sectional barrier. No research has presently been published on the matter. An annular base for the plug material should be in place to conceal thermite while plastified. Tools providing a base in the annular void space are available on the market (Gunnarsson et al. 2016). Assuming a 3" ID and 20m long WL conveyed container an estimated thermite plug height would be 1.43m if set in a 4-1/2" tubing, sitting in an un-cemented 9-5/8" csg in a 12-1/4" borehole. This calculation includes tubular steel as part of the plug volume. In addition to setting only 2.86% of the required plug length, rigging in a 20m WL tool will be a challenge in a stand-alone operation. Stacking several containers, similar to stackable straddles (Agayev et al. 2016), or running several containers by use of deployment BOP, could be an option to supply sufficient plug height.

Qualifying minimum thermite barrier height. Sufficient plug height made of new plugging materials like thermite is not specified in NORSOK D-010 (2013a). The element acceptance criteria (EAC) for a "material plug" are equal to that of cement plug, with plug length and verification methods in mind. Oil & Gas UK (2012b) *Guidelines on qualification of materials for the suspension and abandonment of wells* specify acceptance criteria for mass transportation properties in the qualification process of new materials: "*Since the permanent barrier is effectively reinstating the caprock, the acceptance criteria are based on performance of the caprock. Specifically, the length and permeation characteristics (permeability or diffusion properties) of the barrier should be such that the rate of release of fluids in the well should be equal or lower than that of the caprock once breakthrough has occurred".* Based on Oil & Gas UK (2012b) guidelines, and experiments as presented by Lowry et al. (2015) on thermite plug permeability, a minimum plug height could be estimated. In addition, it is worth mentioning that NORSOK D-010 (2013a) is an industry standard, and not regulation. Other approaches are allowed as long as the operating companies can document that a chosen solution is as good as or better than current regulations.

Thermite placement by circulation. Depending on the results on minimum plug height the viability of a WL conveyed or circulation plug placement technique could be decided. As briefly discussed in Chapter 4, circulation of thermite must be thoroughly investigated to confirm that no un-planned ignition can occur.

Superheated well fluids. All well fluids in close vicinity of the thermite combustion reaction will reach a supercritical state. The effects that these superheated fluids have downhole, and if reaching surface, should be investigated further. Tests have been done to better understand the reaction in wellbore conditions, as described in section 3.2.3, but these test results are not public.

Proposed area of application. Assuming the qualification of a single run WL conveyed thermite plug, it will be a lean method for reservoir P&A, similar to the alternative rigless approach on A-2 (Figure 4.9 and Appendix I). By placing thermite in a cemented 7" or 5-1/2" liner a single WL run could possibly provide sufficient plug height. The same WL tool as described above will provide a 5m thermite plug once set in a 7” liner, which might be sufficient depending on results from qualification testing.

5.3 Rigless P&A using Well Intervention equipment

Well configuration and choice of technology. As seen in the case study, different well configurations require different tools for P&A. While the electric plasma miller was a lean tool for plugging A-1, the same method could not be used for A-2. A-2 was plugged using thermite, due to its un-cemented casing in desired plug interval. While the proposed A-2 approach might be a possibility in the far future, the alternative approach seems more viable with the current R&D results. The complex overburden and un-cemented casing make A-2 and A-3 significantly more challenging to P&A using a rigless approach.

Batch Rigless P&A. A rigless P&A approach must be based on the well configuration complexity. As seen in the Case Study, increasing P&A complexity will shift operations towards rig based P&A. Several NCS wells might be plugged using a rigless approach from start to completion, if they have an advantageous well configuration and relatively simple overburden. Other wells could be candidates for a rigless P&A of the reservoir only. After the reservoir is plugged the overburden zones can be plugged using a rig. Case Study well A-3, and the alternative approach on A-2, are examples of such wells. An estimated six rig-days can be saved on each of these wells utilizing a rigless approach for reservoir abandonment. Significant savings could be obtained utilizing batch rigless reservoir P&A, followed by batch conventional P&A of the overburden. Estimating a platform with 20 wells to be plugged, a total of 120 rig-days could be saved using the approach.

Rigless P&A could potentially take longer time than conventional P&A. The viability of rigless P&A is dependent on its ability to plug a well at lower cost than a rig. As estimated in the Case Study for A-3, the rigless approach should be completed within five days per rig-day to be competitive, based on coiled tubing unit cost being one fifth of rig cost.

NORSOK D-010 rev.4 (2013a). As seen in the case studies, compliance with NORSOK D-010 (2013a) can be a challenge in rigless P&A. A qualification guideline for plugging materials, similar to Oil & Gas UK (2012b), should be considered as a supplement to NORSOK D-010 (2013a). By qualifying new plugging materials, design and verification methods for the specific material could be specified. In addition, NORSOK D-010 (2013a) will need a revision to implement rigless P&A and new technology, as it is presently written with conventional P&A in mind. Verification methods for cement/material plugs, especially for continuous (back-to-back) plugs, should be reconsidered to include rigless P&A technology. Next revision of NORSOK D-

010 (2013a) should open for new approaches to P&A without compromising on barrier integrity. As Case Study of A-2 showed, it is not practical to plug wells using rigless P&A methods while complying with current industry standards.

Well intervention equipment. Several of the technologies presented in Chapter 2 were never included in the case study. Some of these technologies could provide additional information to be used in the P&A design.

The multifinger caliper log, presented in section 2.1.1.1, could provide a status of the casing internal surface condition after the plasma milling operation. The MFC can be run in combination with the cement bond logging tools, verifying that the casing has not been disintegrated or affected by plasma miller heat. This combination was proposed in the A-1 case study.

The annular flow detection tool, presented in section 2.1.1.2, could be run in an investigation WL run prior to any P&A operation. This would give valuable information if there is a suspicion of an annular flow (leading to SCP) in the intended plugging area. By verifying, or locating the flow, the P&A design could be adjusted accordingly. Cost of starting a P&A operation and having to re-assess the approach could potentially be saved.

Similarly an electromagnetic defectoscope for corrosion detection, presented in section 2.1.1.3, could be run in a pre-P&A investigation WL run. Casing condition can be logged through tubing, providing information that could be used in the P&A design.

The abrasive cutter, presented in section 2.3.3, could potentially be used to sever conductors for phase 3 of the P&A. Phase 3 has not been covered as part of the rigless approach. By cutting several pipes using the abrasive cutter, these could be pulled by means of a jacking unit or similar. Although multiple cuts on 13-3/8” and 9-5/8” casings have been done using the technology, tests needs to be conducted to verify its ability to cut typical NCS conductors in range of 20” to 30”.

Intentionally left blank

6. Summary

The objective of this thesis was to investigate the viability of a rigless approach to P&A. By combining conventional well intervention technologies with some emerging high-energy P&A technologies, potential rigless P&A approaches was proposed in a case study. All rigless operations throughout the case study were run through production tubing and X-mas tree in a cased hole environment, without the use of mud.

The rigless P&A approach proposed in case study of A-1 was possible by use of an electric plasma miller, used to disintegrate steel downhole. By removing production tubing, and gaining access to cemented casing, annular barrier verification was possible. A cross-sectional barrier was obtained by setting a cement plug in the logged interval by use of coiled tubing.

Well A-2 in the case study had a more complex well configuration with regards to P&A. This well did not have the desired top of cement in sufficient height above production packer, to utilize the same approach as done on A-1. In the case study of A-2 thermite was used to create a cross-sectional barrier, in areas lacking annular well barrier element. The required volume of thermite, to comply with current NORSOK D-010 plug height specifications, introduced challenges in plugging material placement. The thermite was placed by means of pumping it as slurry. An alternative approach was proposed by use of wireline, although not according to current NORSOK D-010.

The last well in the case study had both a complex overburden and well configuration with regards to P&A. A total of nine formations were to be isolated, and one of them were missing annular barrier in the desired plug setting area. A partial rigless P&A approach was suggested to seal of the two lower zones by use of a similar methodology as on A-1. The remaining formations were left to be plugged by a drilling rig. This extended “pre-P&A” phase could potentially save several rig-days.

The case study showed that different well configurations identified the need for different approaches and technology for P&A. Not all wells are suited for a rigless P&A for the complete work scope, however parts of the plugging could be done without the use of a rig. The major part of the studied wells had a complex well configuration with lack of annular barrier in desired plug setting interval as main contributor to the complexity. Minor changes to NORSOK D-010 could open up for a leaner rigless P&A methodology by specifying design/length requirements and verification methods for new plugging materials. Cement plug verification methods should also be evaluated to include rigless P&A technology. Wells with a complex overburden and well configuration could utilize rigless P&A for batch reservoir abandonment, leaving the overburden to be plugged using a rig. Significant savings could be realized if one, or both, of these technologies are qualified for P&A operations.

Proposed focus areas for rigless P&A viability confirmation can be summarized as:

General findings:

- Modification of NORSOK D-010 to implement new P&A technology and rigless P&A
- Implement plugging material qualification guidelines in NORSOK D-010, similar to Oil & Gas UK *Guidelines on qualification of materials for the suspension and abandonment of wells*. Length requirements/design and verification methods of material plug for P&A purpose should be specified based on qualification results.
- Categorize wells based on P&A complexity, to identify potential rigless P&A candidates.

Electric plasma miller:

- Radial reach of plasma. Confirming that casing and cement integrity are not affected by plasma miller or heat.
- Plasma miller umbilical. Confirm that it is possible to supply sufficient power at typical NCS reservoir barrier depth.
- Through tubing cement bond logging. Confirming alternative tools for bond logging provide sufficient logging data, and verifying in-line centralizer ability to centralize tool string in deviated wells.

Thermite plug:

- Qualify thermite plug according to Oil & Gas UK *Guidelines on qualification of materials for the suspension and abandonment of wells*. Document results and define a minimum plug height based on worst case permeability during experiments.
- Based on findings, confirm the viability of WL conveyance. Investigate possibilities of stacking or running several thermite containers in single run if needed.
- Confirm the thermites ability to create a cross-sectional barrier once set in tubing, with a fluid filled annulus.

7. Future research

This thesis has investigated the possibility to plug platform wells using well intervention equipment in combination with some emerging high energy technologies. This section will propose several aspects that could, or should, be further researched.

Cost and time analysis of case study. This thesis has not provided a thorough time (and cost) analysis of the rigless approach compared to a conventional P&A approach. If sufficient data can be sampled, the case studies could be analyzed and a more decisive conclusion could be made on the viability of a rigless P&A approach.

Surface equipment on rigless P&A. Surface equipment, weight and deck load capacity, crane and accommodation has not been thoroughly investigated in this thesis. A study could be conducted to check how many NCS platforms are candidates to host a rigless P&A operation, with the associated equipment and personnel.

Subsea rigless P&A. As this thesis only investigate platform well P&A, a similar study could be conducted for subsea wells, using Light Well Intervention vessels and emerging technologies. Confirming the viability of subsea rigless P&A operation could be a game changer, even if the approach only could complete parts of the P&A scope.

8. Reference list

(2009), Plasma, In a Dictionary of Physics: Oxford University Press. Retrieved 10 Apr. 2017, from http://www.oxfordreference.com/view/10.1093/acref/9780199233991.001.0001/acref-9780199233991-e-2355

Agayev, F., Gathman, B., Bonnet, T. et al., 2016, Electric Line Deployment of a Stackable Straddle System for Gas Zone Shutoff in a Highly Deviated Extended Reach Borehole, Presented at SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, 22-23 March, Houston, Texas, USA, SPE-179092-MS, https://doi.org/10.2118/179092-MS

Al Furati, M., 2016, A Robust Well Design for Cost-Effective P&A Operation, Master thesis, University of Stavanger, Stavanger, Norway (December 2016)

Al-Dhufairi, M.A., Ghamdi, A.R.A., Lewis, D.R. et al., 2008, Pushing the Wireline Operation to new frontiers, Presented at SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, 1-2 April, The Woodlands, Texas, USA, SPE-113655-MS, https://doi.org/10.2118/113655-MS

Ansari, A.A., Libdi, Z., Kahn, N., 2015, Triple-Barrier Thickness Scanning Using Through-Tubing Ansari, A.A., Libdi, Z., Kahn, N., 2015, Triple-Barrier Thickness Scanning Using Through-Tubing Pulse-Magnetic Logging Tool, Presented at SPE Russian Petroleum Technology Conference, 26-28 October, Moscow, Russia, SPE-176655-MS, https://doi.org/10.2118/176655-MS

Arsalan, A., Ringrose, D., Libdi, Z. et al., 2016, A Novel Strategy for Restoring the Well Integrity by Curing High Annulus-B Pressure and Zonal Communication, Presented at SPE Russian Petroleum Technology Conference and Exhibition, 24-26 October, Moscow, Russia, SPE-181905-MS, https://doi.org/10.2118/181905-MS

Bigelow, E.L., Domangue, E.J. and Lester, R.A., 1990, A New and Innovative Technology for Cement Evaluation, Presented at SPE Annual Technical Conference and Exhibition, 23-26 September, New Orleans, Louisiana, SPE-20585-MS, https://doi.org/10.2118/20585-MS

Camesa, 2016, Electromechanical Cable Catalog, http://www.camesaemc.com/Resource_/PageResource/Camesa%20EMC%20Catalog-Form%201091H-2016.pdf , July 2016, (accessed 12 June 2017).

Çengel,Y.A., Cimbala, J.M. and Turner, R.T., 2012, Appendix,In Fundamentals of Thermal-Fluid Sciences,4th edition, Table A-15, pp.998, New York, NY, McGraw-Hill

Delabroy, L., Rodrigues, D., Norum, E. et al., 2017, Perforate, Wash and Cement PWC Verification Process and an Industry Standard for Barrier Acceptance Criteria, Presented at SPE Bergen One Day Seminar, 5 April, Bergen, Norway, SPE-185938-MS, https://doi.org/10.2118/185938-MS

Farina, H.N., Hafiz, A., Safwan, A. et al., 2015, An Innovative Approach for Tubing Integrity Monitoring With the Application of Electromagnetic Tool and Caliper Tool in Tandem, presented at International Petroleum Technology Conference, 6-9 December, Doha, Qatar, IPTC-18510-MS, https://doi.org/10.2523/IPTC-18510-MS

Ferg, T.E., Lund, H-J., Mueller, D.T., et al. 2011. Novel Approach to More Effective Plug and Abandonment Cementing Techniques. Presented at SPE Arctic and Extreme Environments Conference and Exhibition, 18-20 October, Moscow, Russia, SPE-148640-MS, https://doi.org/10.2118/148640-MS

Fjågesund, T., 2017, What is a barrier?, Oral presentation given at Experimental P&A research for the North Sea Conference, Trondheim, Norway, 20 March.

Gajdos, M., Kocis, I., Mostenicky, I. et al. 2015b, Non-contact Approach in Milling Operations for Well Intervention Operations, Presented at Abu Dhabi International Petroleum Exhibition and Conference, 9-12 November, Abu Dhabi, UAE, SPE-177484-MS, https://doi.org/10.2118/177484-MS

Gajdos, M., Kristofic, T., Jankovic, S. et al., 2015a, Use Of Plasma-Based Tool For Plug And Abandonment, Presented at SPE Offshore Europe Conference and Exhibition, 8-11 September, Aberdeen, Scotland, UK, SPE-175431-MS, https://doi.org/10.2118/175431-MS

Gajdos, M., Mostenicky, I., Kocis, I. et al., 2016, Plasma-Based Milling Tool for Light Well Intervention, Presented at SPE/IADC Middle East Drilling Technology Conference and Exhibition, 26-28 January, Abu Dhabi, UAE, SPE-178179-MS, https://doi.org/10.2118/178179-MS

Ghegadmal, T. and Ponder, A., 2016, Reduce P&A Cost with Section Milling Technology, Presente at IADC/SPE Drilling Conference and Exhibition, 1-3 March, Fort Worth, Texas, USA, SPE-178827-MS, https://doi.org/10.2118/178827-MS

Grotzinger,J. and Jordan,T., 2010, Igneous rocks: Solids from melts. In Understanding Earth, Sixth edition, Rossignol, R.B. and Palmiotto, A., Chapter 4, pp.89-111. New York, NY, W.H. Freeman and Company

Gundersen, J., 2017, Regulations and standards for PP&A, Oral presentation given at Experimental P&A research for the North Sea Conference, Trondheim, Norway, 20 March.

Gunnarsson, B., Tønnesen, S.H., Olsen, E. et al., 2016, Technology Update: New Tool and Sealant Technology Expedites Annular Isolation Tasks, Journal of Petroleum Technology, Volume 68, Issue 07, p.20-21, July, SPE-0716-0020-JPT, https://doi.org/10.2118/0716-0020-JPT

Hemmingsen, P.V., 2017, The importance of experimental P&A research. Oral presentation given at Experimental P&A research for the North Sea Conference, Trondheim, Norway, 20 March.

Hovda, L., 2017, With an operator`s eye: What is P&A?, Oral presentation given at Experimental P&A research for the North Sea Conference, Trondheim, Norway, 20 March.

ICoTA, 2005, International Coiled Tubing Association, An Introduction to Coiled Tubing, History, Applications and Benefits, Texas, U.S.A., rev 102505, Available from: http://www.icota-europe.com/technical/coiled-tubing

Jain, S., Al Hamadi, M.A., Alghasra, A.M. et al., 2016, Well Integrity Management: Analysis of Multi-Barrier Corrosion in Mature Wells Using Advanced Magnetic Impulse Technology, Presented at Abu Dhabi International Petroleum Exhibition & Conference, 7-10 November, Abu Dhabi, UAE, SPE-182968-MS, https://doi.org/10.2118/182968-MS

Johns, J.E., Blount, C.G., Dethlefs, J.C. et al. 2006, Applied Ultrasonic Technology in Wellbore Leak Detection and Case Histories in Alaska North Slope Wells, Presented at SPE Annual Technical Conference and Exhibition, 24-27 September, San Antonio, Texas, USA, SPE-102815-MS, https://doi.org/10.2118/102815-MS

Khalifeh, M., 2016, Materials for Optimized P&A Performance, Potential Utilization of Geopolymers, Doctoral thesis, University of Stavanger. http://hdl.handle.net/11250/2396282

Kocis, I., Kristofic, T., Gajdos, M. et al., 2015, Utilization of Electric plasma for Hard Rock Drilling and Casing Milling, Prenented at SPE/IADC Drilling Conference and Exhibition, 17-19 March, London, England, UK, SPE-173016-MS, https://doi.org/10.2118/173016-MS

Kristofic, T., Kocis, I., Balog, T. et al., 2016, Well Intervention Using Plasma Technologies, Presented at SPE Russian Petroleum Technology Conference and Exhibition, 24-26 October, Moscow, Russia, SPE-182120-MS, https://doi.org/10.2118/182120-MS

Li, J., Misselbrook, J.G. and Seal, J., 2008, Sand Cleanout With Coiled Tubing: Choice of Process, Tools, or Fluids?, Presented at Europec/EAGE Conference and Exhibition, 9-12 June 2008, Rome, Italy, SPE-113267-MS, https://doi.org/10.2118/113267-MS

Log, O., 2016, Centrica Experience with Cap Rock Barriers on Canadian Land Wells, Presentation given at the Norwegian Oil and Gas Association Norwegian Plug & Abandonment Forum (PAF) Workshop, Sola, Norway, 19 October.

Loving, S.W., Ferguson, A. and Hart, R., 2005, Abrasive Cutting Technology Deployed Via Coiled Tubing, Presented at PE/ICoTA Coiled Tubing Conference and Exhibition, 12-13 April, The Woodlands, Texas, SPE-92866-MS, https://doi.org/10.2118/92866-MS

Lowry, W., Dunn, S., Coates, K. et al., 2015, High Performance Ceramic Plugs For Wellbore Sealing, Presented at 15th International High-Level Radioactive Waste Management Conference (IHLRWM 2015), Charleston, SC, April 12-16, pp. 407-413.

Lowry, W.E. and Dunn, S.D, 2016, Well Sealing Via Thermite Reactions, US Patent No. US 9,494,011 B1

Mandal, B. and Quintero, A, 2010, A New Monocable Circumferential Acoustic Scanner Tool (Cast-M) For Cased-Hole And Openhole, Presented at SPWLA 51st Annual Logging Symposium, 19-23 June, Perth, Australia, SPWLA-2010-55460

Moeinikia, F., Fjelde, K.K, Saasen, A., et al., 2014, Evaluating Cost Efficiency of Rigless P&A for Subsea Multiwell Campaign, Presented at IADC/SPE Drilling Conference and Exhibition, 4-6 March, Fort Worth, Texas, USA, SPE-167923-MS, https://doi.org/10.2118/167923-MS

Mortensen, F.M., 2016 A New P&A technology for setting the permanent barriers, Master thesis, University of Stavanger, Stavanger, Norway (June 2016)

Myrseth, V., Perez-Valdes, G. A., Bakker, S.J. et.al. 2017. Development of a Norwegian Open-Source Plug-and-Abandonment Database with Applications. Presented at the SPE Bergen One Day Seminar, Grieghallen, Bergen, 20 April 2016, SPE-180027-PA, https://doi.org/10.2118/180027-MS

National Research Council, 1996, Assessment of cutting techniques, An assessment of techniques for removing offshore structures, Chapter 2, pp. 24-25, Washington DC, U.S.A., National Academy Press

Nessa, J.O., 2012, Setting Plug & Abandonment Barriers with minimum Removal of Tubulars, Master thesis, University of Stavanger, Stavanger, Norway (2012). http://hdl.handle.net/11250/183353

Norsok Standard, 2013a, D-010: Well Integrity in Drilling and Well Operations, Rev. 4, June 2013, Lysaker, Norway: The Norwegian Oil Industry Association.

Norsok Standard, 2013b, D-002: Well Intervention equipment, Rev. 2, June 2013, Lysaker, Norway: The Norwegian Oil Industry Association.

Norwegian Petroleum Directorate (NPD), 2017, Fact page, http://factpages.npd.no/factpages/Default.aspx?culture=no (accessed 12 June 2017)

Oil & Gas UK, 2012a, Guidelines for the suspension and abandonment of wells, Issue 4, July 2012.

Oil & Gas UK, 2012b, Guidelines on qualification of materials for the suspension and abandonment of wells, Issue 1, July 2012.

Oil & Gas UK, 2016, Decommissioning Insight 2016 – Facts and Figures, http://oilandgasuk.co.uk/wp-content/uploads/2016/11/Decommissioning-Insight-Infographics-2016.pdf

Olsen, M., Sætre, T., Hanssen, R. et al., 2017, Improved Through-Christmas-Tree P&A Plug Placement with New Innovative Cementing Methodology, Presented at SPE/IADC Drilling Conference and Exhibition, 14-16 March, The Hague, The Netherlands, SPE-184653-MS, https://doi.org/10.2118/184653-MS

Padilha, S.T.C.dS. and Araju, R.G.dS., 1997, New Approach on Cement Evaluation for Oil and Gas Reservoirs Using Ultrasonic Images, Presented at Latin American and Caribbean Petroleum Engineering Conference, 30 August-3 September, Rio de Janeiro, Brazil, SPE-38981-MS, https://doi.org/10.2118/38981-MS

Portman, L., 2004, Cementing Through Coiled Tubing: Common Errors and Correct Procedures, Presented at SPE/ICoTA Coiled Tubing Conference and Exhibition, 23-24 March, Houston, Texas, SPE-89599-MS, https://doi.org/10.2118/89599-MS

Sawaryn, S.J., Pattillo, P.D., Brown, C., et al. 2015, Assessing Casing Wear in the Absence of a Baseline Calliper Log, Presented at SPE/IADC Drilling Conference and Exhibition, 17-19 March, London, England, UK, SPE-173143-MS, https://doi.org/10.2118/173143-MS

Scanlon, E., Garfield, G. L., Brobak, S. 2011. New Technologies to Enhance Performance of Section Milling Operations that Reduces Rig Time for P&A Campaign in Norway, Presented at SPE/IADC Drilling Conference and Exhibition, 1-3 March, Amsterdam, The Netherlands, SPE-140277-MS, https://doi.org/10.2118/140277-MS

Schwanitz, B. and Henriques, K., 2009, the development of Wireline-Tractor Technology, The Way Ahead, 05, 02, June 2009, SPE-0209-018-TWA, https://doi.org/10.2118/0209-018-TWA

Skjold, M., 2013, Method Of Well Operation, International (PCT) Patent No. WO 2013/135583 A2

Sørgård, E., Østvik, E., Grønnerød, N. et al., 1999, Coiled Tubing Milling and Temporary Plug and Abandonment Operations, Presented at SPE/ICoTA Coiled Tubing Roundtable, 25-26 May, Houston, Texas, SPE-54472-MS, https://doi.org/10.2118/54472-MS

Spieler, J.O. and Monge Øia, T. 2015. P&A – Well statistics. Presentation given at the Norwegian Oil and Gas Association Norwegian Plug & Abandonment Forum (PAF) Workshop, Sola, Norway, 29 October.

Stowe, C. and Ponder, A., 2011, Performance Advance In Section Milling Technology, Presented at SPE Annual Technical Conference and Exhibition, 30 October-2 November, Denver, Colorado, USA, SPE-145957-MS, https://doi.org/10.2118/145957-MS

Straume, M., 2012, Introduction to Plug & Abandonment Forum (PAF), Oral presentation given at Plug and abandonment workshop, Sola, Norway, 14 June.

Straume, M., 2015, P&A in the past, present & in the future, Oral presentation held at PAF Seminar, Sola, Norway, 29 October.

Straume, M., 2016, Possible to increase rigless P&A scope?, Oral presentation held at PAF Seminar, Sola, Norway, 19 October.

Tyndall, J.H., 1990, Segmented Bond Tool - A New Generation Cement Bond Logging Device, Presented at CIM/SPE International Technical Meeting, 10-13 June, Calgary, Alberta, Canada, SPE-21596-MS, https://doi.org/10.2118/21596-MS

Wang, L.L., Munir, Z.A. & Maximov, Y.M., 1993, Thermite reactions: their utilization in the synthesis and processing of materials, Journal of Materials Science, Vol.28(14), pp.3693-3708, http://dx.doi.org/10.1007/BF00353167

Williams, S.M., Carlsen, T., Constable, K.C. et al., 2009, Identification and Qualification of Shale Annular Barriers Using Wireline Logs During Plug and Abandonment Operations, Presented at SPE/IADC Drilling Conference and Exhibition, 17-19 March, Amsterdam, The Netherlands,
SPE-119321-MS, https://doi.org/10.2118/119321-MS

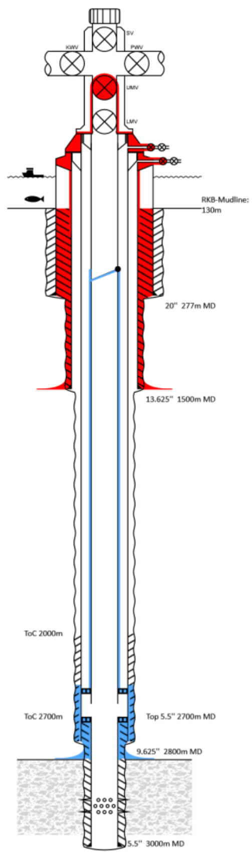
Zakaria, M., Al-Shehri, A., Tammar, H., 2010, The Application of Precision Ultrasonic Technologies to Diagnose and Identify Crossflow between Formations, Flow behind Pipe and Casing Leaks, Presented at SPE/DGS Saudi Arabia Section Technical Symposium and Exhibition, 4-7 April, Al-Khobar, Saudi Arabia, SPE-136922-MS, https://doi.org/10.2118/136922-MS

Appendix

Appendix A: WBS status prior to P&A

Universitetet i Stavanger

Field : Wittberg	Well design pressure 345 Bar
Well : Example	Reservoir pressure 345 Bar
Schematic : US.P 4.1-a1 rev. 1	Prepared By : Stian Wittberg
Date : 22.May.2017	Verified By :



Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

Producer

Production

Draft

Primary barrier elements

Element	Qualification	Monitoring
Downhole safety valve	Inflow test to xxx bar	Tubing pressure
Tubing	Pressure test to xxx bar	A-annulus pressure
Production packer	Pressure test to xxx bar	A-annulus pressure
Liner top packer	Pressure test to xxx bar	A-annulus pressure
Production liner	Pressure test to xxx bar	B-annulus pressure
Production casing	Pressure test to xxx bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production liner cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Suspension x-mas tree	Pressure test to xxx bar	Pressure tested to xxx bar
Spool wellhead A with access valve	Pressure test to xxx bar	External observation
Spool wellhead	Pressure test to xxx bar	External observation
Intermediate casing	Pressure test to xxx bar	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

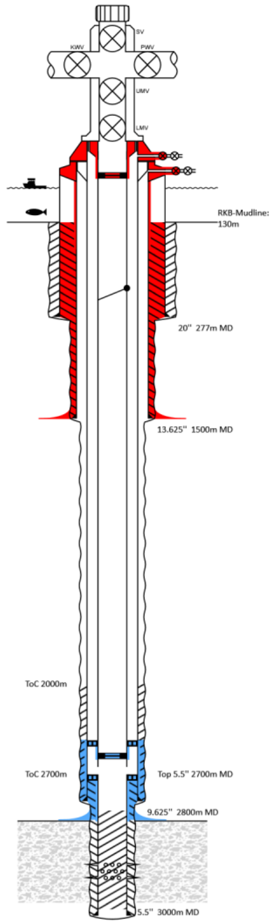
Note:

Appendix A: Well Barrier Schematic of example well prior to pre-P&A phase (during production). Produced using *Wellbarrier* software

Appendix B: WBS status after pre-P&A operation

Universitetet i Stavanger

Field : Wittberg	Well design pressure 345 Bar
Well : Example	Reservoir pressure 345 Bar
Schematic : US.P 5.1-a1 rev.1	Prepared By : Stian Wittberg
Date : 22.May.2017	Verified By :



Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

P&A preparation

Pre P&A

Draft

Primary barrier elements

Element	Qualification	Monitoring
Deep set tubing plug	Inflow test to xxx bar	Pressure above valve
Tubing	Pressure test to xxx bar	A-annulus pressure
Production packer	Pressure test to xxx bar	A-annulus pressure
Liner top packer	Pressure test to xxx bar	A-annulus pressure
Production liner	Pressure test to xxx bar	B-annulus pressure
Production casing	Pressure test to xxx bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production liner cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Tubing hanger	Pressure test to xxx bar	A-annulus pressure
Deep set tubing plug	Inflow test to xxx bar	Pressure above valve
Tubing	Pressure test to xxx bar	A-annulus pressure
Spool wellhead A with access valve	Pressure test to xxx bar	External observation
Spool wellhead	Pressure test to xxx bar	External observation
Intermediate casing	Pressure test to xxx bar	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

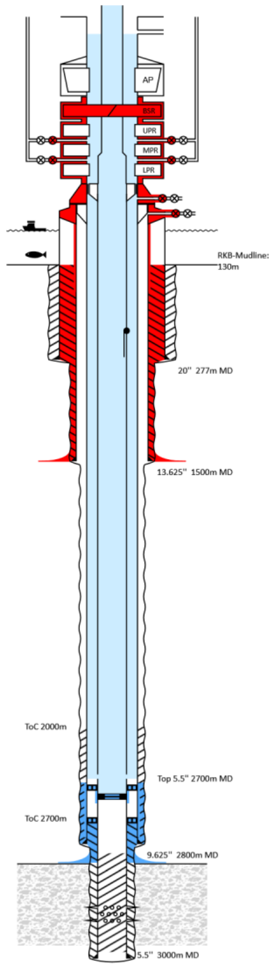
Note:

Appendix B: Well Barrier Schematic of example well after pre-P&A phase. X-mas tree can be removed and drilling BOP installed. Produced using *Wellbarrier* software.

Appendix C: WBS status prior to P&A, BOP installed

Universitetet i Stavanger

Field : Wittberg	Well design pressure 345 Bar
Well : Example	Reservoir pressure 345 Bar
Schematic : US.P 5.7-a1 rev.1	Prepared By : Stian Wittberg
Date : 22.May.2017	Verified By :



Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

Permanent abandonment

Pre- Phase 1 P&A

Draft

Primary barrier elements

Element	Qualification	Monitoring
Production packer	Pressure test to xxx bar	A-annulus pressure
Shallow set plug	Pressure test to xxx bar	Pressure above plug
Liner top packer	Pressure test to xxx bar	A-annulus pressure
Production liner	Pressure test to xxx bar	B-annulus pressure
Production casing	Pressure test to xxx bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Production liner cement	Formation test, job performance or bond log	B-annulus pressure
Wellbore fluid	Fluid sg control based on expected pore pressure	Triptank level and fluid sg control
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Drilling BOP	Pressure test to xxx bar	Frequent pressure testing to xxx bar
Spool wellhead A with access valve	Pressure test to xxx bar	External observation
Spool wellhead	Pressure test to xxx bar	External observation
Intermediate casing	Pressure test to xxx bar	B-annulus pressure
Intermediate casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:

Appendix C: Well Barrier Schematic of example well after installation of BOP, while pulling tubing. Produced using *Wellbarrier* software.

Appendix D: WBS status permanent P&A completed

Universitetet i Stavanger

Field : Wittberg
Well : Example
Schematic : US.P 5.7-b1 rev.1
Date : 13.Jun.2017

Well design pressure 345 Bar
Reservoir pressure 345 Bar
Prepared By : Stian Wittberg
Verified By :

Permanent abandonment

P&A Complete

Draft

Primary barrier elements

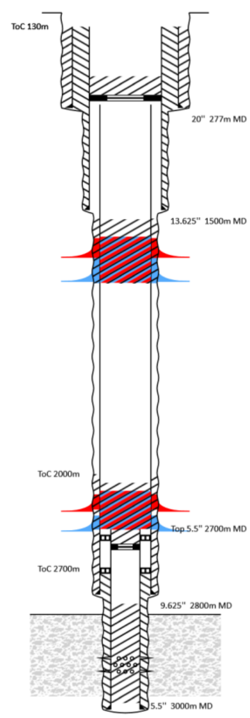
Element	Qualification	Monitoring
Cement plug	Pressure test to xxx bar	Pressure above plug
Cement plug	Pressure test to xxx bar	Pressure above plug
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Secondary barrier elements

Element	Qualification	Monitoring
Cement plug	Pressure test to xxx bar	Pressure above plug
Cement plug	Pressure test to xxx bar	Pressure above plug
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Healthy well, no or minor issue

Note:



Depth reference is RKB Jack up rig
Depth correlation

Prepared by Universities

Appendix D: Well Barrier Schematic after completion of permanent plug and abandonment operations. Produced using *Wellbarrier* software

Appendix E: Time estimate A-1 Jack-up rig operation

A-1 Conventional P&A approach - Step-list		*Ref Section 4.1.1*		
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
	Prepare well for nippling (WL and kill well)			
	Rig Up Wireline Equipment			1,2
	Run Drift Run - Included equalising DHSV.			0,7
	Bullhead well to seawater			0,5
	Run and install deep set bridgeplug. Test same			0,6
	Punch ASV. Pressure up tbg to release ASV			0,3
	Cut tubing above the production packer			0,4
	Install DHSV hold open sleeve			0,3
	Circulate tubing and annulus to seawater			0,2
	Run and install shallow set bridgeplug			0,1
	Rig down wireline equipment.			0,9
	Sum			**5,2**
	Jack-up ops			
	Skid rig, N/D X-mas tree and NU and test BOP			1,3
	Retrieve tubing down to P&A depth			2,1
	9 5/8" Clean Out Run			0,7
	Cement log			0,8
	Set Reservoir plug			1,6
	Cut and pull 9 5/8" casing from required surface plug depth			2,2
	13 3/8" Casing Clean Out			0,4
	Set EZSV and establish surface plug			1,9
	Sum			**11,0**
	Phase 3: Pull conductor			
	Cut and Pull casing/conductor to subsea			4,6
	Sum			**4,6**

Appendix F: Detailed step list for A-1 Rigless P&A approach

A-1 Rigless Through Tubing P&A approach - Detailed step-list				Ref Section 4.1.2
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
1	Rig up wireline			1,2
2	Drift well for bridge plug and plasma bit	3670		0,7
3	Bullhead tubing to seawater			0,5
3.1	2 x tubing volume of 39 m3			
4	Set bridge plug in 5-1/2" liner above perforations	3600		0,6
4.1	Pressure test plug to 53 bar. Inflow test plug to max differential pressure of 26,5 bar.			
5	Punch tubing above production packer	3510		0,3
5.1	Keep 10 bar over-pressure on tubing side at TD to confirm punch			
5.2	An option could be to pull GLV and circulate through SPM	3297		
6	Displace annulus gas (lift gas) to seawater			0,2
6.1	Annulus volume estimated to 76 m3			
6.2	Evaluate to punch and release ASV for better circulation. Should be done prior to step 5.			
6.3	Rig over to CT with Plasma bit umbilical reel			?
7	Disintegrate minimum 100m of 5-1/2" 20ppf tubing in area above OBF #1	3320-3210		
7.1	Control radial reach of plasma to not damage 9-5/8" casing and cement.			
7.2	Estimated rat-hole fill in the below 5,5" tubing and liner: Assuming a tubing cuttings structure porosity of 50% and 50% cuttings bed porosity. Total of 0,42 m3 disintegrated steel will produce 0,83 m3 of cuttings and need a 1,62 m3 rat hole. This equals a total of 152m of 5,5" 20ppf liner. Top of fill will be at 3448m			
7.3	Estimated time consumption on steel disintegration		39	1,6
7.4	Rat-hole area has a maximum well deviation of <30 degree. Cuttings will settle on top of bridgeplug from 3600m upwards.			
7.5	Rig over/Change reel to conventional CT			?
8	Jet wash cement plug setting area	3320-3210		1
8.1	Evaluate to tag rat-hole cuttings, to confirm top of cuttings depth	3448		
8.2	Evaluate to clean out rat hole if plug needs to be set deeper. Average cuttings density estimated to 4,44sg. Most cuttings in range of 1mm to 5mm, as described in Chapter 3. Lift calculations of cuttings not performed as part of thesis.			
8.3	Rig up wireline equipment on top of CT pressure control equipment.			0,5

9	Run ultrasonic bond log with MFC for cement and casing evaluation	3320-3210	18	0,75
9.1	Tool to pass 4,56"ID DHSV and centralize in 8,53"ID of 9-5/8" csg. Preferred USI rotating head not able to pass restrictions. Well fluids (brine instead of mud) will somewhat compensate for the smaller rotating head. Preffered slip over centralizers are not buildt to pass tubing restrictions, in-line centralizers available, but not optimal for tool lift.			
9.2	Might have to remove larger section of tubing to identify 2 x 30m MD of cement bond			
9.3	Alternative tools that will not have same ID/OD challenge are available and can be used depending on required logging data. Segmented Bond Tool could be an option for TT P&A			
10	Set inflatable packer to act as base for cement plug, Test to 70 bar	3315		0,5
10.1	Rig down WL from CT stack-up.			0,25
11	Set a 50m cement plug using CT, to act as primary barrier for reservoir and OBF#1	3315-3265		?
11.1	WOC			?
12	Tag and pressure test cement plug. Pressure test to LOT + 70 bar: 222bar using 1,03sg seawater			?
13	Set a 50m cement plug using CT, to act as secondary barrier for reservoir and OBF#1	3265-3215		?
13.1	Set directly on top of primary cement plug			
13.2	WOC			?
14	Tag and pressure test cement plug. Pressure test to LOT + 70 bar: 222bar using 1,03sg seawater			?
14.1	Change reel/rig over to plasma bit umbilical			?
15	Disintegrate minimum 50m of 5,5" 20ppf tubing in area above OBF #2	1070-1010		
15.1	Estimated cuttings height in 5,5" tubing based on same assumptions as for previous section: 83m			
15.2	Estimated time consumption on steel disintegration		21,3	0,9
16	Disintegrate minimum 50m of 9-5/8" 53,5ppf production casing in area above OBF#2	1070-1010		
16.1	Estimated cuttings height in 5,5" tubing based on same assumptions as for previous section: 220m			
16.2	Estimated time consumption on steel disintegration		56,2	2,3
16.3	Rig over/change reel to conventional CT			?
17	Jet wash cement plug setting area.			1
18	Set inflatable packer to act as base for cement plug, Test to 70 bar	1065		0,5
19	Set a 50m cement plug to act as both primary barrier for OBF#2 and as an open-hole to surface plug.	1065-1015		?
19.1	WOC			?
20	Tag and pressure test cement plug. Pressure test to LOT + 70 bar: 142 bar using 1,03sg seawater			?
21	Rig down equipment			0,9

step list point	A-1 Rigless P&A. Well calculations appendix to detailed operational step list.					
3)	**Tubing volume estimate**					
	Di in	Area m2	length m	volume m3		
	4,653	0,01097	3568	**39,1**		
	Pressure test calculations					
4)	Plug depth m	TVD estimate m	Formation pressure bar	Hyd head of seawater bar	Diff pressure bar	**surface pressure needed bar**
	3600	2900	320	293,0	27,0	**54,0**
6)	**Annulus volume estimate**					
	Di in	Do in	Area m2	length m	volume m3	
	8,535	5,5	0,0215838	3510	**75,8**	

step list point			
7.2)	**Rat hole fill estimation**		
	meters of 5,5 20# removed	110	m
	Top of milled window	**3210**	m
	Bottom milled window	**3320**	
	Estimated plug setting interval	**110,0**	m
	steel volume m3 of 5,5 20# pr meter	0,003774	m3
	volume m3 of disintegrated steel	0,42	m3
	Disintegrated material volume including material porosity of 50%	0,83	m3
	Estimated volume of cuttings bed including 50% bed porosity	1,66	m3
	Area (volume per meter) of 5,5 tubing/liner	0,01097	m2
	Volume of rat hole above plug in 5,5" liner and tubing	3,07	m3
	Length of 5,5" available	280,00	m
	Remaining volume of cuttings to fill 9-5/8" rat hole	0,00	m3
	Area (volume per meter) in 9-5/8 casing	0,036912	m2
	Estimated height of cuttings bed in 5,5	151,3746	
	Estimated height of cuttings bed in 9-5/8	0,0	m
	Estimated depth of top cuttings bed (cut at 3510m	**3448,6**	m

7.3)	**Estimated time used on disintegrating**		
	Length of disintegrated tubing	110,0	m
	Weight pr meter of tubing	29,8	kg/m
	Total mass to disintegrate	3278,0	kg
	Estimated steel removal rate	84,0	kg/h
	Estimated time consumed	39,0	hours

8.2)	**Average cuttings density**			
	Steel density	**pore fluid density**	**porosity**	**Average density**
	7,85	1,03	0,5	4,44

Cement plug pressure test calculations

	Plug base mMD	TVD estimated m	FIT/LOT EMW s.g	Formation LOT pressure bar	Test pressure bar	Hyd head of seawater bar	**surface pressure needed bar**
12)	3315	2540	1,64	408,6	478,6	256,6	**222,0**
14)	3265	2540	1,64	408,6	478,6	256,6	**222,0**
20)	1065	1065	1,72	179,7	249,7	107,6	**142,1**

15.1)	**Rat hole surface plug**		
	meters of **5,5 20#** removed	60	m
	Top of milled window	**1010**	m
	steel volume m3 of 5,5 20# pr meter	0,003774	m3/m
	volume m3 of disintegrated steel	0,23	m3
	Disintegrated material volume including material porosity of 50%	0,45	m3
	Estimated volume of cuttings bed including 50% bed porosity	0,91	m3
	Area (volume per meter) of 5,5 tubing/liner	0,01097	m2
	Estimated cuttings height	82,56797	m
	Volume of rat hole above plug in 5,5" liner and tubing	11,08	m3
	Estimated depth of top cuttings bed (cement top @ 3100)	**3017,4**	m

15.2)	**Estimated time used on disintegrating**		
	Length of disintegrated tubing	60,0	m
	Weight pr meter of tubing	29,8	kg/m
	Total mass to disintegrate	1788,0	kg
	Estimated steel removal rate	84,0	kg/h
	Estimated time consumed	**21,3**	hours

	Rat hole surface plug from 9-5/8		
16.1)	meters of **9-5/8 53.5#** removed	60	m
	Top of milled window	**1010**	m
	steel volume m3 of 9-5/8 53,5# pr meter	0,01003	m3/m
	volume m3 of disintegrated steel	0,60	m3
	Disintegrate material volume including material porosity of 50%	1,20	m3
	Estimated volume of cuttings bed including 50% bed porosity	2,41	m3
	Area (volume per meter) of 5,5 tubing/liner	0,01097	m2
	Estimated cuttings height	219,4257	m
	Volume of rat hole above plug in 5,5" liner and tubing	11,08	m3
	Estimated depth of top cuttings bed (cement top @ 3100)	**2798,0**	m
16.2)	**Estimated time used on disintegrating**		
	Length of disintegrated tubing	60,0	m
	Volume to remove	0,6	m3
	Density steel	7850,0	kg/m3
	Total mass to disintegrate	4724,1	kg
	Estimated steel removal rate	84,0	kg/h
	Estimated time consumed	**56,2**	hours

Appendix G: Time estimate A-2 Jack-up rig operation

A-2 Conventional P&A approach - Step-list				*Ref Section 4.2.1*
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
	Prepare well for nippling (WL and kill well)			
	R/U WL			1
	Pull DHSV			0,4
	Drift well to HUD			0,4
	Punch hole for plasma cutter			0,4
	Cut tubing			0,4
	Set shallow bridge plug			0,5
	R/D WL			1
	Circ kill mud			0,5
	Sum			**4,6**
	Jack-up ops			
	Skid rig, N/D X-mas tree and NU and test BOP			2,1
	Retrieve tubing down to P&A depth			2,0
	R/U and Run USIT log and MFC			1,1
	9 5/8" Clean Out Run			1,2
	Set Reservoir plug 1			3,0
	Set Reservoir plug 2			3,0
	Set Intermediate plug 1			2,6
	Set Intermediate plug 2			2,6
	Cut and pull 9 5/8" casing from required surface plug depth			2,2
	13 3/8" Casing Clean Out			0,9
	Set EZSV and establish surface plug			1,7
	Sum			**22,5**
	Phase 3: Pull conductor			
	Cut and Pull casing/conductor to subsea			2,0
	Sum			**2,0**

Appendix H: Detailed step list for A-2 Rigless P&A approach

No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
	A-2 Rigless Through Tubing P&A approach - Detailed step-list	**Ref Section 4.2.2**		
1	Rig up wireline			1
2	Drift well for plasma bit	3223		0,4
2.1	Pull WRSCSSV first			0,4
2.2	Tag HUD at top of cement plug			
3	Punch tubing above production packer	2915		0,4
4	Displace well to seawater			0,5
4.1	Tubing volume estimated to 21,7m3			
4.2	Annulus-A volume estimated to 77,7m3			
4.3	Rig over to CT with plasma miller umbilical			?
5	Disintegrate tubing using plasma bit. Remove minimum 100m of 4,5" tubing above scab liner top packer	2920-2820		
5.1	Estimated rat-hole fill in 5,5" liner with 50% porosity in tubing cuttings structure and 50% porosity of cuttings bed. Total of 0,26m3 disintegrated steel will produce 0,51m3 cuttings and need a 1,02m3 rat-hole. This equals a total of 84,3m in 5,5" 17ppf liner. Top of fill will be at 3138,7m. This is below plug setting area.			
5.2	Well has a maximum inclination of 30 deg, cuttings should fall into sump/rat-hole.			
5.3	Estimated time consumption of disintegration		24	1
5.4	Rig over/change reel to conventional CT			?
6	Set inflatable packer and heat insulating materialabove scab liner packer in 9-5/8" casing	2915		0,5
6.1	PT to 70 bar			
7	Place diluted thermite to swage casing into formation and create 50m cross-sectional primary reservoir barrier	2915-2865		?
7.1	Place 3,3m3 thermite. 3,3m3 is the estimated volume of a 50m interval of 12,25" borehole excluding steel volume of 9-5/8" casing.			
7.2	Evaluate to place thermite as slurry using CT due to big volumes			
7.3	3,3m3 equals 90m height in 9-5/8"ID			
7.4	Wait on thermite cooling			?
8	Tag and pressure test to LOT + 70bar: 291 bar			?

9	Place diluted thermite to swage casing into formation and create 50m cross-sectional secondary reservoir barrier	2865-2815		?
9.1	Place 3,3m3 thermite. 3,3m3 is the estimated volume of a 50m interval of 12,25" borehole excluding steel volume of 9-5/8" casing.			
9.2	Evaluate to place thermite as slurry using CT due to big volumes			
9.3	3,3m3 equals 90m height in 9-5/8"ID			
9.4	Wait on thermite cooling			?
10	Tag and pressure test to LOT + 70bar: 291 bar			?
10.1	Rig over/change reel to plasma bit umbilical			?
11	Disintegrate tubing using plasma bit. Remove minimum 100m of 4,5" tubing above OBF #1	1710-1600		
11.1	Estimated rat-hole fill with 50% porosity in tubing cuttings structure and 50% porosity of cuttings bed. Total of 0,26m3 disintegrated steel will produce 0,51m3 cuttings and need a 1,02m3 rat-hole.			
11.2	Estimated time consumption of disintegration		24	1
11.3	Rig over/change reel to conventional CT			?
12	Set inflatable packer and heat insulating material in 9-5/8" casing	1715		0,5
12.1	PT to 70 bar			
13	Place diluted thermite to swage casing into formation and create 50m cross-sectional primary reservoir barrier	1715-1665		?
13.1	Place 3,3m3 thermite. 3,3m3 is the estimated volume of a 50m interval of 12,25" borehole excluding steel volume of 9-5/8" casing.			
13.2	Evaluate to place thermite as slurry using CT due to big volumes			
13.3	3,3m3 equals 90m height in 9-5/8"ID			
13.4	Wait on thermite cooling			?
14	Tag and pressure test to LOT + 70bar: 225 bar			?
15	Place diluted thermite to swage casing into formation and create 50m cross-sectional secondary reservoir barrier			?
15.1	Place 3,3m3 thermite. 3,3m3 is the estimated volume of a 50m interval of 12,25" borehole excluding steel volume of 9-5/8" casing.			
15.2	Evaluate to place thermite as slurry using CT due to big volumes			
15.3	3,3m3 equals 90m height in 9-5/8"ID			
15.4	Wait on thermite cooling			?
16	Tag and pressure test to LOT + 70bar: 225 bar			?
16.1	The following steps could be more effective to complete at a later stage. The well is at this stage secured.			
16.2	Rig over/change reel to plasma bit umbilical			?

17	Disintegrate minimum 50m of 4,5" tubing in area above 20! Shoe	530-470		
17.1	Estimated rat-hole fill with 50% porosity in tubing cuttings structure and 50% porosity of cuttings bed. Total of 0,26m3 disintegrated steel will produce 0,51m3 cuttings and need a 1,02m3 rat-hole.			
17.2	Estimated time consumption of disintegration		24	1
18	Disintegrate minimum 50m of 9-5/8" csg in same area	530-470		
18.1	Estimated rat-hole fill with 50% porosity in casing cuttings structure and 50% porosity of cuttings bed. Total of 0,6m3 disintegrated steel will produce 1,2m3 cuttings and need a 2,6m3 rat-hole.			
18.2	Estimated time consumption of disintegration		56,2	2,3
18.3	Rig over/change reel to conventional CT			?
19	Set and pressure test an inflatable packer with heat insulating material to act as base for thermite mixture	525		0,5
19.1	PT to 35 bar			
20	Plase thermite to create a 50m cross-sectional open hole to surface barrier	525-475		?
20.1	Place 4m3 of thermite to create 50m plug			
20.2	Wait on thermite to cool			?
21	Tag and pressure test plug to LOT + 35 bar: 84 bar			?
22	Rig down equipment			1

A-2 Rigless P&A. Well calculations appendix to detailed operational step list.

Step list point						
4)	**Tubing volume estimate**					
	Di in	Area m2	length m	volume m3		
	3,833	0,007444	2915	**21,7**		
	Annulus volume estimate					
	Di in	Do in	Area m2	length m	volume m3	
	8,535	4,5	0,026651	2915	**77,7**	
5)	**Rat hole fill estimation**					
	meters of 4,5 12,6# removed				110	m
	Top of milled window				**2810**	m
	Estimated plug setting interval				**110,0**	m
	steel volume m3 of 4,5 12,6# pr meter				0,002323	m3/m
	volume m3 of disintegrated steel				0,26	m3
	Disintegrated material volume including material porosity of 50%				0,51	m3
	Estimated volume of cuttings bed including 50% bed porosity				1,02	m3
	Area (volume per meter) of 5,5 tubing/liner				0,01213	m2
	Volume of rat hole above plug in 5,5" liner and tubing (90meters)				3,64	m3
	Estimated height of cuttings bed in 5,5 liner				84,3	m
	Estimated depth of top cuttings bed				**3138,7**	m
5.3)	**Estimated time used on disintegrating**					
	Density of steel				7850,0	kg/m3
	Total volume of disintegrated steel				0,3	m3
	Total mass to disintegrate				2005,9	kg
	Estimated steel removal rate				84,0	kg/h
	Estimated time consumed				23,9	hours
7)	**Thermite plug volume estimate**					
	borehole total volume					
	Di in	Area m2	plug length m	volume m3		
	12,25	0,076038	50	**3,80188955**		

volume of casing steel

Di in	Do in	Area m2	length m	volume m3
9,625	8,535	0,01003	50	**0,501498526**

Volume of thermite needed

	borehole volume	casing volume	thermite volume	
7.1	3,80189	0,501499	**3,300391**	m3

Height of thermite in 9-5/8"

	Di in	Area m2	Volume needed	Height in 9-5/8
7.3)	8,535	0,036912	3,300391	**89,4130753**

10) Top of primary plug, worst case if no radial expansion into 12-1/4 borehole

base of plug	height thermite	top thermite
2915	89,41308	**2825,587**

10) **Cement plug pressure test calculations**

	Plug base mMD	TVD estimated m	FIT/LOT EMW s.g	Formation pressure bar	Test pressure bar	Hyd head of seawater bar	**surface pressure needed bar**
res pri	2915	2715	1,86	495,4	565,4	274,3	**291,1**
res sec	2815	2625	1,86	479,0	549,0	265,2	**283,7**
int pri	1715	1650	1,98	320,5	390,5	166,7	**223,8**
int sec	1665	1600	1,98	310,8	380,8	161,7	**219,1**
surface	525	525	1,98	102,0	137,0	53,0	**83,9**

Rat hole surface plug from 9-5/8

16.1)	meters of **9-5/8 53.5#** removed	60	m
	Top of milled window	**470**	m
	steel volume m3 of 9-5/8 53,5# pr meter	0,010029971	m3/m
	volume m3 of disintegrated steel	0,60	m3
	Disintegrated material volume including material porosity of 50%	1,20	m3
	Estimated volume of cuttings bed including 50% bed porosity	2,41	m3

16.2)	**Estimated time used on disintegrating**		
	Length of disintegrated tubing	60,0	m
	Volume to remove	0,6	m3
	Density steel	7850,0	kg/m3
	Total mass to disintegrate	4724,1	kg
	Estimated steel removal rate	84,0	kg/h
	Estimated time consumed	**56,2**	hours
11)	Thermite plug volume estimate		
	borehole total volume		

Di in	Area m2	plug length m	volume m3
12,5	0,079173	50	**3,96**

Appendix I: A-2 Partial Rigless approach to P&A

A-2 Partial Rigless Through Tubing P&A approach - Step-list				Ref Figure 4.9
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
	TOC Reservoir/perforations squeezed cement below 9-5/8" shoe			
	Well intervention operations			
	Rig up WL		24	1,0
	Pull DHSV			0,4
	Run driftrun to HUD	3648		0,4
	Set bridgeplug to act as base for thermite	3645	12	0,5
	Run dump bailer and place heat insulating material on top of plug	3645	12	0,5
	Plug could be excluded and material dumped directly on top of cement			
	Set primary thermite plug in area between 9-5/8" shoe and liner top packer	3648-3565	12	0,5
	Plug height not according to current NORSOK specifications			
	Wait on thermite to cool		?	
	Tag and pressure test plug. Could be tagged using stroker (max 33.000lbs force)		12	0,5
	Run dump bailer to place heat insulating material directly on top of primary thermite plug		12	0,5
	Set secondary thermite plug		12	0,5
	Plug height not according to current NORSOK specifications			
	Wait on thermite to cool		?	
	Tag and pressure test plug. Could be tagged using stroker (max 33.000lbs force)		12	0,5
	Punch tubing		12	0,5
	Cut tubing at P&A depth	1700	12	0,5
	Set shallow bridge plug and test same (e-Red smart sub)		12	0,5
	Rig down WL		24	1,0
	Displace well to kill mud		12	0,5
	Sum			**8,3**

	Jack up operations			
	Skid rig, N/D X-mas tree and NU and test BOP			2,1
	Retrieve tubing down to P&A depth			2,0
	R/U and Run USIT log and MFC			1,1
	9 5/8" Clean Out Run			1,2
	Setintermediate plug 1			2,6
	Set intermediate plug 2			2,6
	Cut and pull 9 5/8" casing from required surface plug depth			2,2
	13 3/8" Casing Clean Out			0,9
	Set EZSV and establish surface plug			1,7
	Sum			**16,5**
	Pull conductor			
	Cut and pull casing/conductor to subsea			2,0
	Sum			**2,0**

Appendix J: Time estimate A-3 Jack-up rig operation

A-3 Conventional P&A approach - Detailed step-list		Ref Section 4.3.1		
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
	Prepare well for nippling (WL and kill well)			
	No data recieved			
	Jack-up operation			
	Skid rig, N/D XMT & N/U BOP		27,25	1,1
	Recover Production tubing		83,75	3,5
	Clean out and log 9-5/8" casing		37	1,5
	Restore Reservoir and OBF#1 barrier		87	3,6
	Restore OBF#2 barrier		102,5	4,3
	Kill B-annulus		31,5	1,3
	Remove C-section		70,75	2,9
	Clean out and log 13-3/8" casing		46,25	1,9
	Restore OBF#3 barrier		44,5	1,9
	Restore OBF #4,#5,#6,#7 barrier		39,25	1,6
	Kill C-annulus		0	0,0
	Remove B-section		19,25	0,8
	Cut and recover 13-3/8" casing		147,5	6,1
	Clean out and log surface casing		22,5	0,9
	Install surface barrier		17	0,7
	N/D BOP & riser		10,5	0,4
	Sum			**32,8**
	Phase 3: Pull conductor			
	No data recieved			

Appendix K: A-3 Partial Rigless approach to P&A

A-3 Rigless Through Tubing P&A approach - Detailed step-list		Ref Section 4.3.2		
No.	OPERATION	Depth [mMD]	Time [Hours]	Time [Days]
1	Rig up CT unit			
2	Drift well to top of perforations	2791		
3	Set cement plug from top perforations to top of reservoir	2791-2699		
4	Tag cement plug, pressure and inflow test	2699		
4.1	Rig over/change reel to plasma bit umbilical			
5	Disintegrate minimum 50m of 5-1/2" liner using plasma bit to expose 7-5/8" cemented liner	2660-2606		
5.1	Rig up WL on top of CT stack up			
6	Log 7-5/8" liner using SBT	2660-2606		
7	Set an inflatable packer to act as base for cement plug and test same	2660		
7.1	Rig over/change reel to conventional CT			
8	Set 50m cement plug in 7-5/8" liner to act as primary barrier for reservoir.	2660-2610		
9	Tag and pressure test barrier plug			
9.1	Rig over/change reel to plasma bit umbilical			
10	Disintegrate minimum 50m of 5-1/2" liner in area below WEG using plasma bit to expose 9-5/8" cemented production casing	2567-2510		
10.1	Rig over/change reel to conventional CT			
11	Clean out plasma cuttings bet to gain minimum 50m plug setting interval			
11.1	Minimum 36m of cuttings bed must be cleaned out.			
11.2	Rig up WL on top of CT stack up			
12	Log 9-5/8" casing cement in plug setting interval using SBT			
13	Set inflatable packer to act as base for secondary reservoir cement plug			
13.1	Rig down WL and up CT			
14	Set 50m cement plug in 9-5/8" prod. Csg. to act as secondary barrier for reservoir.			
15	Tag and pressure test barrier plug			
15.1	Rig over/change reel to plasma bit umbilical			
16	Disintegrate minimum 100m of tubing using plasma bit in area above OBF #1			
16.1	Rig up WL on top of CT stack up			
17	Log 9-5/8" casing cement in plug setting interval using SBT			
18	Set inflatable packer to act as base for for cement plug, test same			

18.1	Rig down WL and up conventional CT			
19	Set 50m cement plug to act as primary barrier for OBF#1			
20	Tag and pressure test primary barrier plug			
21	Set a 50m cement plug to act as secondary barrier for OBF#1			
22	Tag and pressure test secondary barrier plug			
23	Set hold open/wear sleeve in DHSV			
24	Set shallow "pump open" bridge plug and test same			
25	Rig down equipment			
26	Displace well to kill mud			
	Jack up rig to continue plugging operation			

A-3 Rigless P&A. Well calculations appendix to detailed operational step list.			
step list point			
5)	**Rat hole fill estimation**		
	meters of 5,5 20# removed	54	m
	Top of milled window	**2606**	m
	Bottom milled window	**2660**	
	Estimated plug setting interval	**54,0**	m
	steel volume m3 of 5,5 20# pr meter	0,003774	m3
	volume m3 of disintegrated steel	0,20	m3
	Disintegrated material volume including material porosity of 50%	0,41	m3
	Estimated volume of cuttings bed including 50% bed porosity	0,82	m3
	Area (volume per meter) of 5,5 tubing/liner	0,01097	m2
	Estimated height of cuttings bed in 5,5	74,31117	m
	Available rat hole	80	m
11)	**Rat hole fill estimation**		
	meters of 5,5 20# removed	57	m
	Top of milled window	**2510**	m
	Bottom milled window	**2567**	
	Estimated plug setting interval	**57,0**	m
	steel volume m3 of 5,5 20# pr meter	0,003774	m3
	volume m3 of disintegrated steel	0,22	m3
	Disintegrated material volume including material porosity of 50%	0,43	m3
	Estimated volume of cuttings bed including 50% bed porosity	0,86	m3
	Area (volume per meter) of 5,5 tubing/liner	0,01097	m2
	Estimated height of cuttings bed in 5,5	78,43957	m
	Available rat hole	43	m
	Estimated volume to be cleaned out	0,39	m3
	Estimated height to be cleaned out	35,44	