University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/Specialization: **Master of Science in Petroleum Engineering, Drilling and Well Technology**	Spring semester, 2016 Open
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Thesis title: **Method selection study of future plug and abandonment at Gjøa field**	
Credits (ECTS): 30	
Key words: **Plug and Abandonment** **Gjøa field** **Regulations** **NORSOK** **Technology** **Challenges**	Pages: 122 + enclosure: 3 Stavanger, 14.06.2016

Acknowledgement

For the past 5 months I have been working on my Master's thesis for the Faculty of Science and Technology, at the University of Stavanger, as the final part of my Drilling Engineer Master's programme. I would like to use this opportunity to express my gratitude to several people who have assisted me during this semester.

Throughout my work on this thesis, I have received valuable guidance and information from my two supervisors at the university. Firstly, I would like to thank Professor Kjell Kåre Fjelde, not only for being a source inspiration as a teacher at the university, but also for giving me the chance to write my final thesis under his supervision. Also, I want to thank PhD student Fatemeh Moeinikia for providing me with important information and for always taking the time to help when I needed assistance.

I would also like to express gratitude to ENGIE Exploration and Production (E&P) as a company for providing me with this assignment and for allowing me to use their office at Forus. A special message of gratitude goes to Manager Drilling and Well Gerhard Sund, Senior Drilling Engineer Mehryar Nasseri, Drilling Project Manager Karstein Hagenes and Drilling Engineer Dwayne W. Martins at ENGIE for our weekly meetings, where I was provided with guidance, information, encouragement and excellent feedback.

My thanks also go to Interwell AS for taking the time for a meeting and for presenting an update on their newly-developed technology.

Finally, I would like to use this opportunity to thank my family and pregnant wife for the patience they have shown me, throughout long days at the library.

Abstract

On the Norwegian Continental Shelf (NCS) there will be a wave of subsea and platform wells that will eventually need to be plugged and abandoned (P&A'd) in a safe and efficient manner. The well abandonment phase is the final stage performed on the well, and it includes the establishment of permanent well barriers to protect the environment.

All offshore hydrocarbon (HC) wells will, sooner or later, require permanent P&A in order to control subsurface pressures and prevent the free flow of pore fluids to the seafloor. There is a large diversity of well types to be P&A'd. Some less complex wells can be plugged either by existing rig-less platform equipment, or by a vessel technology. Other more complex wells will need a rig that can handle more challenging and heavy P&A operations, including heavy retrieval of tubing and casing, milling and cement repairs.

This thesis will discuss the process of permanently implementing P&A on the subsea wells on the Gjøa field, given that sometime in the future these wells will need to be P&A'd due to declining production. There are currently eleven production wells at the field, and these wells can be categorized based on differences in well design. This thesis also covers an overview of rules and regulations governing P&A activities on the NCS. "*P&A of offshore wells represents a significant cost and liability to operating companies and national authorities, while at the same time being governed by prescriptive downhole requirements. Current requirements are prescriptive as to the number and size of permanent well barriers required, and the requirements are the same for all types of wells" [1].*

The main focus of this thesis is on technical solutions that are available today, but it will also discuss the possibility of performing a final P&A job through the use of more time and cost-effective solutions. P&A creates no added value for operators and therefore the operation should be done as quickly and cost-effectively as possible. Today's conventional technology is in many ways outdated, and to make P&A economically sustainable in the future there is a great need for new technology and methods.

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List of Abbreviations

ALARP	As Low as Reasonable Possible
BOP	Blow Out Preventer
CBL	Cement Bond Log
CDF	Cumulative Distribution Function
DIACS	Downhole, Instrumentation and Control System
E&P	Exploration and Production
FWR	Final Well Report
HSE	Health, Security and Environment
HC	Hydrocarbon
LWIV	Light Well Intervention Vessel
NCS	Norwegian Continental Shelf
MODU	Mobile Offshore Drilling Unit
NORSOK	the Norwegian Shelf's competitive position
NPT	Non Productive Time
O&G	Oil and Gas
P&A	Plug and Abandonment
PAF	Plug and Abandonment Forum
PDF	Probability Density Function
PSA	Petroleum Safety Authority
RMR	Riserless Mud Recovery
TVD	True Vertical Depth
USIT	UltraSonic Imager Tool
VDL	Variable Density Log
WBE	Well Barrier Element
WBEACT	Well Barrier Element Acceptance Criteria Tables
WBS	Well Barrier Schematic
WH	Wellhead
WL	Wireline
WOR	Workover Riser
WOW	Waiting on Weather
XMT	Xmas Tree
HXMT	Horizontal Xmas Tree

VXMT Vertical Xmas Tree

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1 Introduction

The objective of this thesis is to examine how to plan a technical suitable and cost-effective abandonment operation for future P&A of the subsea wells on the Gjøa field. The well abandonment plan will be in accordance with the Norwegian Shelf's competitive position (NORSOK) standard D-010, which will serve as references in the authorities' regulations. The thesis comprises the following chapters:

- Chapter 1: Introduction of the thesis
- Chapter 2: Laws, regulation and standards to be followed on NCS
- Chapter 3: Brief description of P&A concept, general operation sequence and challenges related to P&A operation
- Chapter 4: Presentation of the Gjøa field, reservoir, drilling and categorization of the wells
- Chapter 5: A discussion of future P&A possibilities at Gjøa field
- Chapter 6: Discussions
- Chapter 7: Conclusion

1.1 Background

P&A has gained a lot of focus in Norway during the past few years due to a growing number of fields that are in their final production phase, and which are going to be closed down. When production from an oil and gas (O&G) well is no longer viable, the well has reached the end of its life, and needs to be P&A'd. This operation can be divided into several phases starting with killing the well, and ending with wellhead (WH) and conductor removal.

This complex and time-consuming operation will impose an enormous cost on the government and operating companies. P&A could easily constitute 25% of the total costs of drilling exploration wells offshore Norway [2]. It is therefore important to implement the P&A strategy early in the design phase in order to reduce the costs of the decommissioning phase.

1.2 Scope of study

Gjøa is a combined O&G field located in the North Sea, operated by ENGIE E&P Norge AS. The field has been producing since 2010, and has been developed with four subsea templates and one single satellite well connected to a semi-submersible production and processing facility. It is currently producing from eleven subsea wells with different well configurations. Reservoir depth is around 2200 metres Total Vertical Depth (mTVD), and in the overburden of the Gjøa field there is a potentially abnormal pressured zone in the Kyrre formation, which in this thesis is assessed to be a potential source of inflow. The flow potential and plugging requirements for each zone have been analyzed. Production rates at Gjøa field will decline slightly towards 2019 and the following years, shown in figure 1.

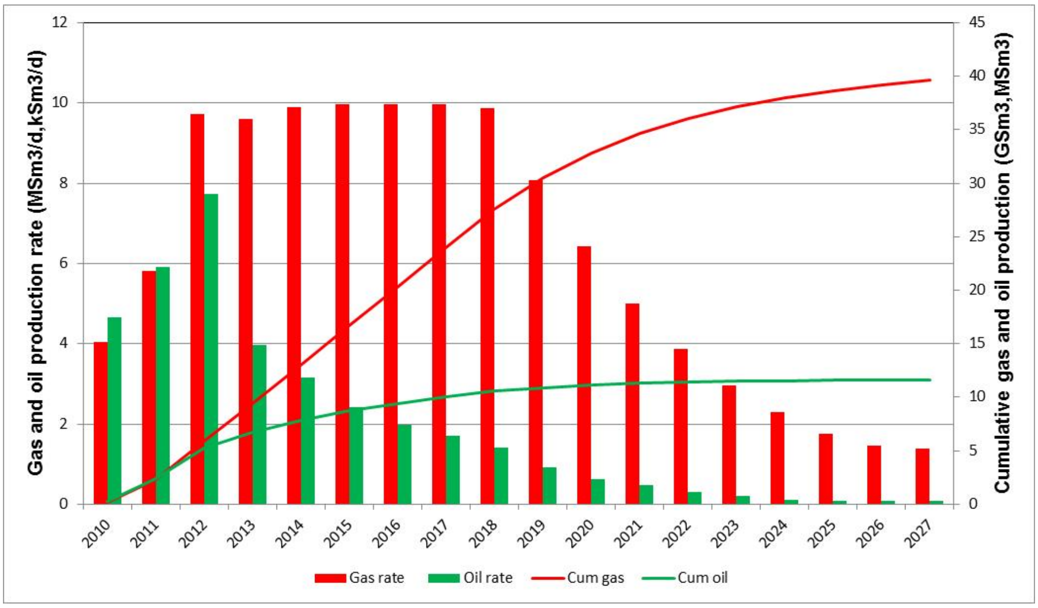


Figure 1 Production profile for The Gjøa field [3]

According to the petroleum act, a decommissioning plan shall be submitted at the earliest five years prior to or, at the latest, two years prior to the time the use of a facility is expected to be permanently P&A'd [4]. The overall objective of this thesis is, therefore, to establish an operation programme for future P&A of the wells in a safe and efficient manner.

For that purpose, this project consists of a theoretical part that intends to introduce the regulations that should be understood, as these regulations constitute a major driver for the whole P&A process.

Thereafter, it will go through a general operational procedure, vessels used and challenges faced during a P&A operation. The Gjøa field is presented in chapter 4, and a proposal for a thorough step-by-step elaboration of the operation itself will be discussed in chapter 5.

New innovative technologies are under development, and future operations may be more efficient in changing the whole procedure, some of which procedure, together with probabilistic time estimation for a single well on the Gjøa field, is discussed in chapter 6. The final part of the thesis, with a conclusion, is presented in chapter 7.

2 Permanent P&A – Laws, Regulations and Standards

The rules and regulations governing the activities of O&G companies consist of various laws, regulations, guidelines and standards implemented by the government. This chapter will provide the reader with an understanding of which regulatory bodies control the P&A activities on the NCS. Figure 2 shows the Norwegian Governing Hierarchy to which the Norwegian petroleum industry is subject.

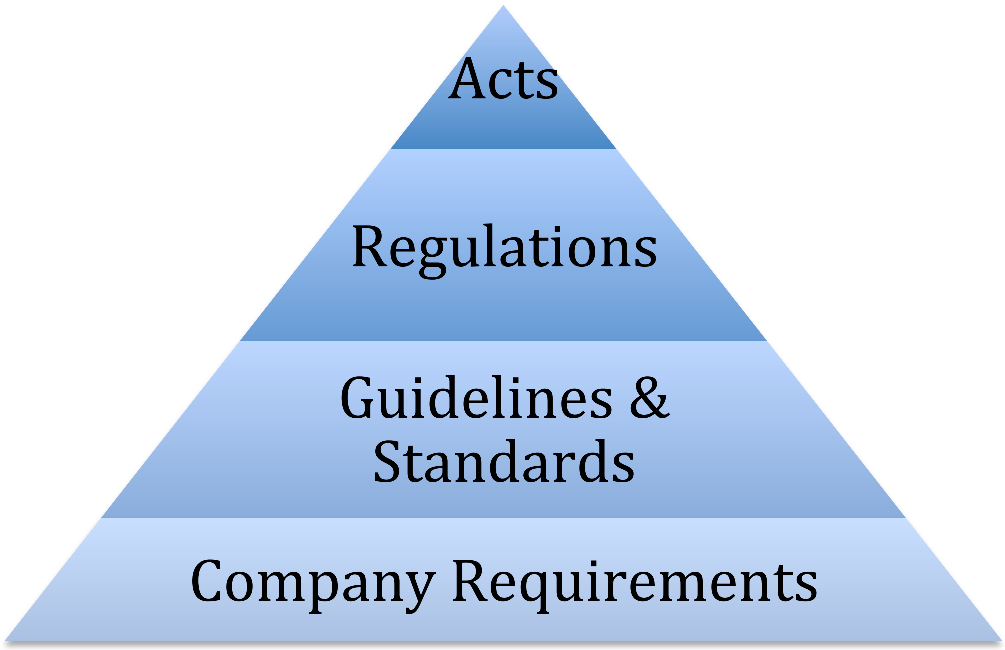


Figure 2 Governing Hierarchy of the petroleum operations

Decommissioning activities on the NCS are defined in the 1996 Petroleum Act and regulated by the Petroleum Safety Authority (PSA). The rules and regulations issued by PSA cover all phases of the activities, such as planning, engineering, construction, use and final removal. The guidelines often refer to recognized standards as a way of fulfilling the functional requirements in the regulations. Specific abandonment regulations are developed in NORSOK D-010 *Well Integrity in Drilling and Well Operations*. The standard defines the minimum functional and performance-oriented requirements and guidelines for well design, planning and execution of safe well operations in Norway [5].

2.1 Definition of Plug and Abandonment

NORSOK D-010 covers the requirements and guidelines for well integrity during plugging of wells on NCS, and accordingly divides P&A into two types: temporary and permanent abandonment [5]. By defining terms such as *plugging, temporary abandonment and permanent abandonment,* the reader will hopefully be provided with an understanding regarding the definition of P&A.

- ***Plugging:*** *"operation of securing a well by installing required well barriers".*
- ***Temporary Abandonment with/without monitoring:*** *"well status, where the well is abandoned and the primary and secondary well barriers are/are not continuously monitored and routinely tested".* The intention is to temporarily plug the well, where the well is abandoned and/or the well control equipment is removed, with the possibility to re-enter or permanently abandon in the future.
- ***Permanent Abandonment:*** *"well status, where the well is abandoned permanently and will not be used or re-entered again".*

In this thesis the main emphasis will be focused towards permanent P&A, as the objective is to permanently abandon the wells on the Gjøa field. The purpose of P&A is to establish permanent barriers to prevent migration of HC from reservoirs to the surface. All wells, whether they function as exploration, production or injection wells, shall at some point be plugged with an eternal perspective, with no visible traces of the well architecture or subsea installation at the seabed. The decision to permanently P&A a well is often taken when the production from a well is no longer profitable. This is usually after logs have determined there is insufficient HC potential to complete the well, or after production operations have drained the reservoir.

2.2 The Petroleum Act

The Petroleum Act (Act No. 72 of 29 November 1996 relating to petroleum activities) provides the general legal basis for the licensing system that governs Norwegian petroleum activities [4]. The requirement for a Decommissioning plan is implemented in the Petroleum Act and in section 5-1 *Decommissioning plan* it is stated:

*"The licensee **shall** submit a decommissioning plan to the Ministry before… The plan **shall** contain proposals for continued production or shutdown of production and disposal of facilities. Such disposal may inter alia constitute further use in the petroleum activities, other uses, complete or part removal or abandonment.*

*Unless the ministry consents to or decides otherwise, the decommissioning plan **shall** be submitted at the earliest five years, but at the latest two years prior to the time when the use of a facility is expected to be terminated permanently."*

This forms the basis of this study, where the Petroleum Act requires licensees to submit a cessation plan to the Ministry two to five years before the production licence expires, or use of the facility ceases.

2.3 The Petroleum Safety Authority

The Norwegian PSA is an independent government regulatory body under the Ministry of Labour and Social Affairs. The PSA, established on January 1 2004, was separated from Norwegian Petroleum Directorate, and was established as an independent regulatory body [6]. The organization has the main focus areas illustrated in figure 3.

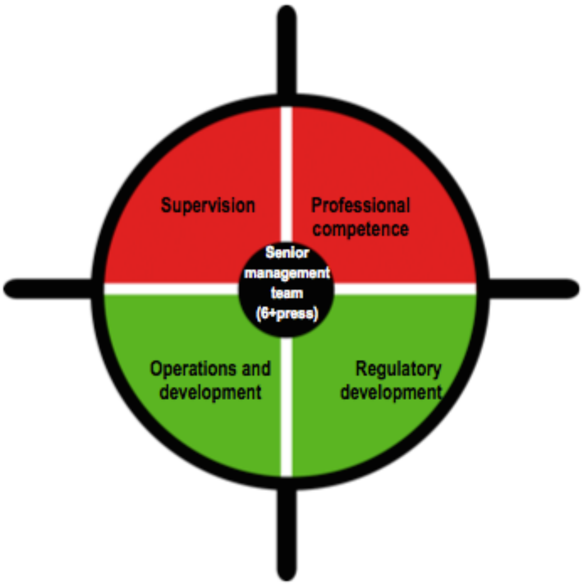


Figure 3 PSA logo and focus areas [7]

The PSA is responsible for developing and enforcing regulations that govern safety and working environment in all phases of the petroleum activities on the NCS and associated land facilities [8]. The PSA have specified several regulations in accordance with the Petroleum Act §10-18, and the four most central regulations relevant for petroleum activities offshore are:

1. The Framework HSE regulations
2. The Management regulations
3. The Facilities regulations
4. The Activities regulations

Before proceeding further into the regulations and NORSOK D-010 there are two terms that must be defined [5]:

- **Should**: *"verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that a certain course of action is preferred but not necessarily required."*

- **Shall**: *"verbal form used to indicate requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted, unless accepted by all involved parties."*

The most important sections in the petroleum regulations regarding P&A operations are:

The Facilities Regulations - §48 Well Barriers [9]

- *"Well barriers **shall** be designed such that well integrity is ensured and the barrier functions are safeguarded during the well's lifetime.*
- *Well barriers **shall** be designed such that unintended well influx and outflow to the external environment is prevented, and such that they do not hinder well activities.*
- *When a production well is temporarily abandoned without a completion string, at least two qualified and independent barriers **shall** be present.*
- *When a well is temporarily or permanently abandoned, the barriers **shall** be designed such that they take into account well integrity for the longest period of time the well is expected to be abandoned.*
- *When plugging wells, it **shall** be possible to cut the casings without harming the surroundings. The well barriers **shall** be designed such that their performance can be verified."*

The Activities Regulations - §88 Securing wells *[10]*

- *"All wells **shall** be secured before they are abandoned so that well integrity is safeguarded during the time they are abandoned, cf. Section 48 of the Facilities Regulations. For subsea-completed wells, well integrity **shall** be monitored if the plan is to abandon the wells for more than twelve months.*
- *Exploration wells commenced after 1.1.2014 **shall** not be temporarily abandoned beyond two years.*
- *In production wells abandoned after 1.1.2014, HC-bearing zones **shall***

be plugged and abandoned permanently within three years if the well is not continuously monitored.

- *It **shall** be possible to check well integrity in the event of reconnection on temporarily abandoned wells.*
- *Abandonment of radioactive sources in the well **shall** not be planned. If the radioactive source cannot be removed, it **shall** be abandoned in a prudent manner."*

To elaborate on this, the guidelines are referring to the NORSOK D-010 standard to be used to fulfil these requirements. A more thorough review on NORSOK D-010 will be given in the next section.

2.4 NORSOK D-010, rev. 4

The NORSOK standard is the result of collaboration between actors in the oil industry, Norwegian industry and government. The standards have been developed to ensure adequate safety and added value, in order to ensure cost effectiveness and to eliminate unnecessary activities in offshore field developments and operations. The objective of the NORSOK standards is, as far as possible, to replace individual oil company specifications and other industry guidelines for use in existing and future petroleum industry developments [5].

The NORSOK standard D-010 *Well Integrity in Drilling and Well Operations* defines the minimum functional and performance requirements and guidelines relating to well integrity in drilling and well activities. The standard is central insofar as the establishment of barriers and abandonment activities on the NCS are concerned.

Well integrity is an important term throughout drilling and well operations and is defined to be *"application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well [5]".*

2.4.1 Well Barriers

A well barrier is defined as *"an envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment [5]"*. The well barriers **shall** be established prior to performing an operation by identifying the required well barrier elements (WBE) that is present during the operation. A well barrier consists of one or several WBE, which together form a barrier envelope around the reservoir. A WBE is *"a physical element which in itself does not prevent flow but in combination with other WBEs forms a well barrier [5]"*.

The minimum number of barriers that is required when permanently abandoning a well depends on different factors such as type and number of source of inflow, as illustrated in table 1 below. In this context, a source of inflow has the same meaning as a reservoir and is defined as "*a formation which contains free gas, movable HCs, or abnormally pressured movable water [5]".*

For HC bearing formations from moderate to significant flow potential, a minimum of two independent barriers **shall** be included in the well abandonment design. Having two independent permanent well barriers increases the level of reliability, and ensures adequate safety and redundancy.

Table 1 Minimum number of well barriers [5]

Minimum number of well barriers	Source of inflow
One well barrier	a) Undesirable cross flow between formation zones b) Normally pressured formation with no HC and no potential to flow to surface c) Abnormally pressured HC formation with no potential to flow to surface
Two well barriers	d) HC bearing formations e) Abnormally pressured formation with no potential to flow to surface

The primary well barrier, shown in blue in figure 4, is the first well barrier to prevent unintentional flow, while the secondary well barrier (red) is the second object that prevents unintentional flow from a potential source of inflow, working as a backup for the primary well barrier. In addition to having primary and secondary barriers for sealing the HC bearing formations, the well **shall** have an open hole to a surface barrier, also known as environmental plug, which is a "fail safe" well barrier to isolate flow paths in the wellbore. Its function is to permanently isolate flow conduits from exposed formation(s) to surface, after casing(s) are cut and retrieved [5].

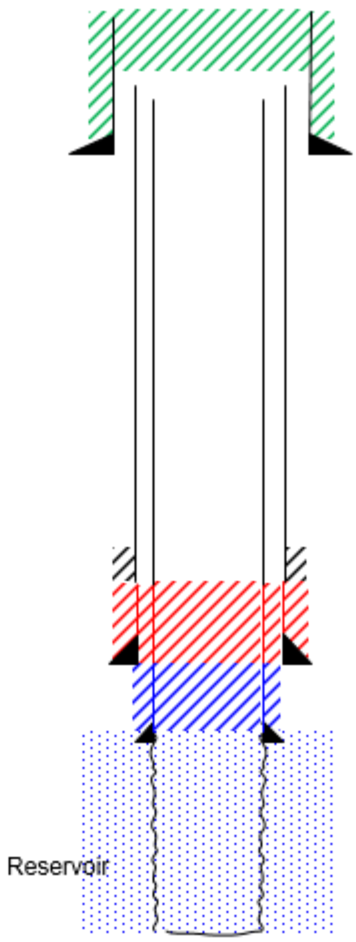


Figure 4 Example of Permanent P&A of a well with one reservoir

A well barrier schematic (WBS) **shall** be prepared for each well activity and operation showing the different well barriers and the associate WBEs [5]. A WBS illustrates what the well barriers will be for different scenarios in a well. An example on how to present a WBS is shown in figure 5 below for one of the oil producers on the Gjøa field during production. The primary well barrier is shown in blue colour and the secondary well barrier in with red.

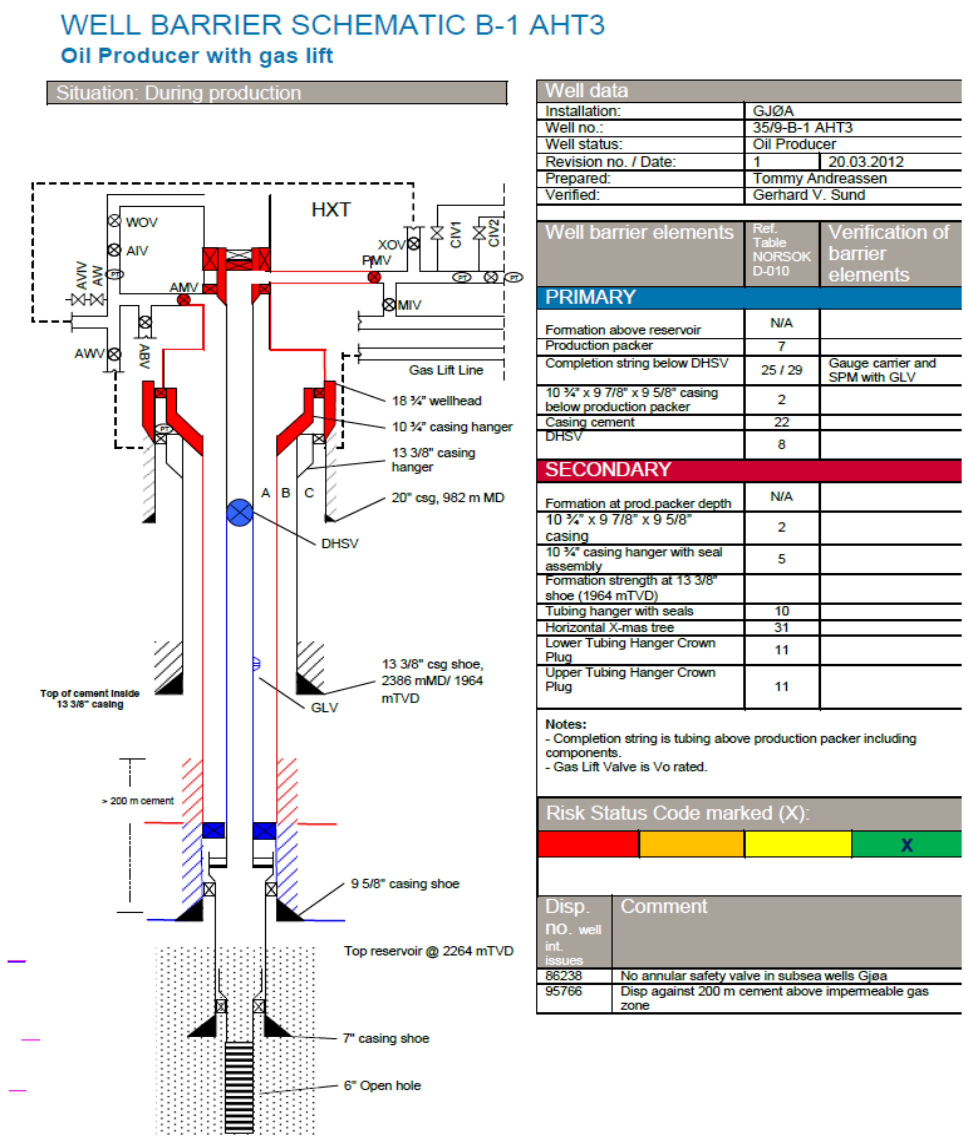


Figure 5 Well barrier schematic of an oil producer with gas lift during production [11]

Additional information presented in a WBS is referenced to well barrier elements acceptance criteria tables (WBEACT). In Chapter 15 of NORSOK D-010, specific technical and operational requirements and guidelines relating to WBEs are collated in WBEACT that **shall** be applicable for all types of activities and operations.

According to NORSOK D-010 a WBS **should** also be made [5]:

a) "When a new well component is acting as a WBE;

b) For illustration of the completed well with XT (planned and as built);

c) For recompletion or workover on wells with deficient WBEs; and

d) For final status of permanently abandoned wells."

2.4.2 Permanent P&A

Permanent abandonment is already defined as *"a well status, where the well is abandoned and will not be used or re-entered again"*. Permanently abandoned wells **shall** be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes [5]. This means that the well **shall** be sealed to the extent that a leak will never occur.

A permanent well barrier **shall** extend across the full cross section of the well and include all annuli and seals, both vertically and horizontally, as illustrated in figure 6. This means that an internal cement plug placed inside a casing is not valid as a barrier unless there is verified good-quality cement on the outside of the casing, as steel tubular alone is not accepted as a permanent WBE [5].

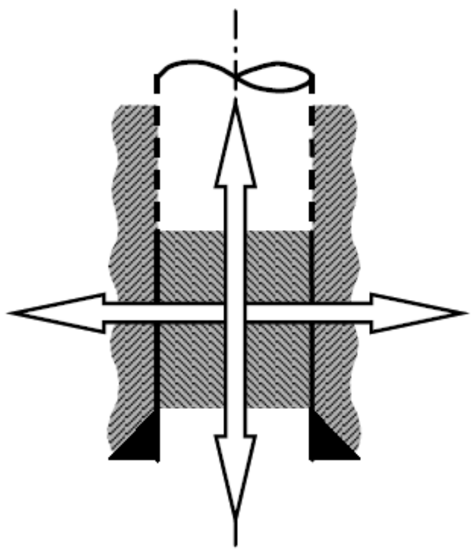


Figure 6 Permanent well barrier [5]

The well barriers **shall** be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure, so that the formation does not constitute a weak spot creating a potential leak passage around the cement plug.

2.4.2.1 Requirements for permanent well barriers

NORSOK does not state what materials to use as a permanent WBE. This is, to a large extent, up to the operators. However, the suitability of the selected plugging materials **shall** be verified and documented. A permanent well barrier **shall** have the following characteristics [5]:

a) *"Provide long-term integrity (eternal perspective);*
b) *Impermeable;*
c) *Non-shrinking;*
d) *Able to withstand mechanical loads/impact;*
e) *Resistant to chemicals/ substances (H2S, CO2 and HCs);*
f) *Ensure bonding to steel;*
g) *Not harmful to the steel tubulars' integrity."*

The characteristics listed above are there to ensure the safety and integrity of the barriers after abandonment on the long-term. Cement is the most common permanent WBE used, since it fulfils the requirements and is well proven.

Removal of downhole equipment is required when this can cause loss of well integrity. Control lines and cables **shall** not form part of the permanent well barrier as these could be a potential leak path.

2.4.2.2 Positioning of well barriers

Ultimately the reservoir plugs **should** be placed as close to the top of the reservoir as possible, but as a minimum NORSOK's requirement is that the base of the primary and secondary well barriers **shall** be positioned at a depth where formation integrity is higher than the potential pressure below [5].

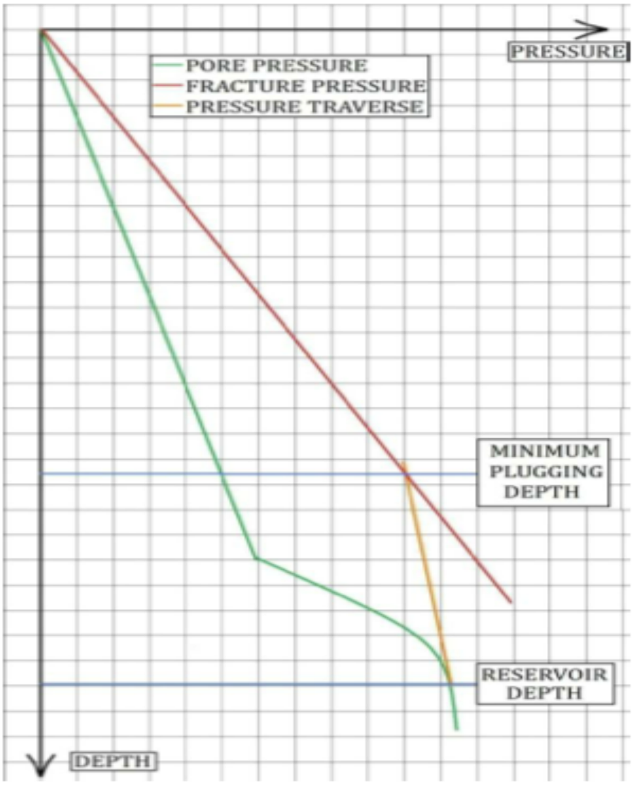


Figure 7 The fracture pressure of the formation rock dictates the minimum setting depth [12]

This is to ensure that the formation will not fracture under pressure and create potential leak paths around the barrier. The minimum setting depth for placement of primary and secondary barriers can be calculated from equation 5.

$$P_{\text{int}} = BHP - \rho_{fluid} * g * (TVD_{reservoir} - x) \tag{1}$$

$$P_{frac} = g * \rho_{frac} * x \tag{2}$$

As 1 ≤ 2

$$BHP - (\rho_{fluid} * g * TVD_{res}) + (\rho_{fluid} * g * x) = g * \rho_{frac} * x \tag{3}$$

$$BHP - \rho_{fluid} * g * TVD_{res} = g * x * (\rho_{frac} - \rho_{fluid}) \tag{4}$$

$$x = \frac{BHP - \rho_{fluid} * g * TVD_{res}}{g * (\rho_{frac} - \rho_{fluid})} \tag{5}$$

Where

P_{int} = Internal pressure [Bar]

P_{frac} = Formation fracture pressure [Bar]

BHP = Bottom Hole Pressure [Bar]

x = Minimum depth of base [m]

TVD_{res} = Total Vertical Depth to top of reservoir [m]

ρ_{frac} = Formation fracture [SG]

ρ_{fluid} = Well fluid [SG]

g = Gravitational constant (0.0981 kg*m/s^2)

If ρ is given as gradient:

$$x = \frac{BHP - \rho_{fluid} * TVD_{res}}{\rho_{frac} - \rho_{fluid}} \tag{6}$$

Where

ρ_{frac} = Formation fracture gradient [Bar/m]

ρ_{fluid} = Well fluid gradient [Bar/m]

2.4.2.3 Length requirements of well barriers

NORSOK D-010 section 9.6.3.1 and 9.6.3.2 gives requirements for external and internal WBEs.

"The external WBE (e.g. casing cement) ***shall*** *be verified to ensure a vertical and horizontal seal. The requirement for an external WBE is 50 m with formation integrity at the base of the interval. If the casing cement is verified by logging it only requires a minimum of 30 m interval with acceptable/good cement bonding to act as a permanent WBE. The interval* ***shall*** *have formation integrity [5]".*

Furthermore, it states that the casing cement **shall** be verified by logging for critical cement jobs and for permanent P&A where the same casing cement is part of the primary or secondary barriers.

"An internal WBE (e.g. cement plug) ***shall*** *be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and* ***shall*** *be minimum 50 m if set on a mechanical plug/cement as foundation, otherwise according to EAC 24 [5]".*

EAC is the acronym for Element Acceptance Criteria. As already mentioned there are various WBEACT, which can be found in chapter 15 of NORSOK D-010. The minimum cement plug length for different scenarios is summarized in table 2.

Table 2 Minimum cement plug lengths [5]

Open hole cement plug	Cased hole cement plug	Open hole to surface plug (installed in surface casing)
100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing **should** extend at least 50 m MD above and below casing shoe.	50 m MD if set on a mechanical/cement plug as foundation. Otherwise 100 m MD.	50 m MD if set on a mechanical plug. Otherwise 100 m MD.

In section 9.6.6 in NORSOK D-010 there are illustrations of different permanent abandonment options one can choose from, by combining mechanical plugs and cement. The choice will, to a large extent, be affected by the well and abandonment design.

Open hole with cement plug

An abandonment of an open hole using a cement plug is achieved by setting a primary cement plug that consists of 100 m of cement across/above the reservoir; this is extended for a minimum 50 m above the reservoir. There is a secondary cement plug 50 m below, and 50 m above the casing shoe. The requirement is to have sufficient formation integrity at the base of both well barriers.

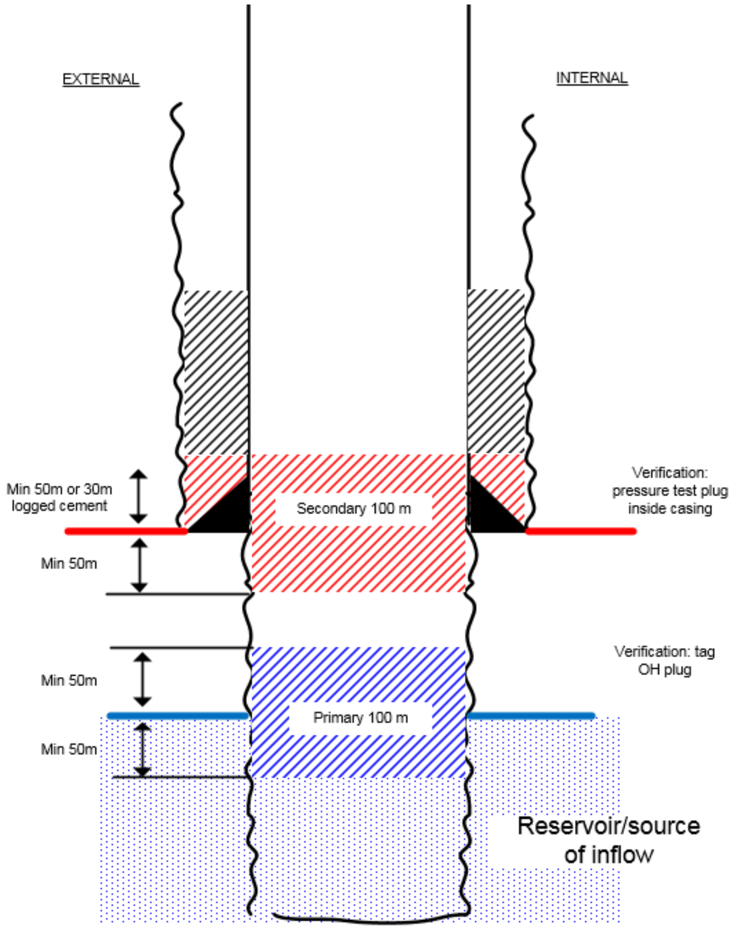


Figure 8 Permanent abandonment, open hole with cement plugs [5]

Back to back plug

Abandonment of open hole or a perforated casing/liner is abandoned by setting two back-to-back cement plugs from the reservoir. The primary cement plug consists of a minimum of 100 m of cement from the reservoir, which is extended 50 m below and above the casing shoe. The secondary cement plug is 50 m set on the primary plug. The external cement height is minimum 50 m, or 30 m, provided that the casing cement is verified by logging.

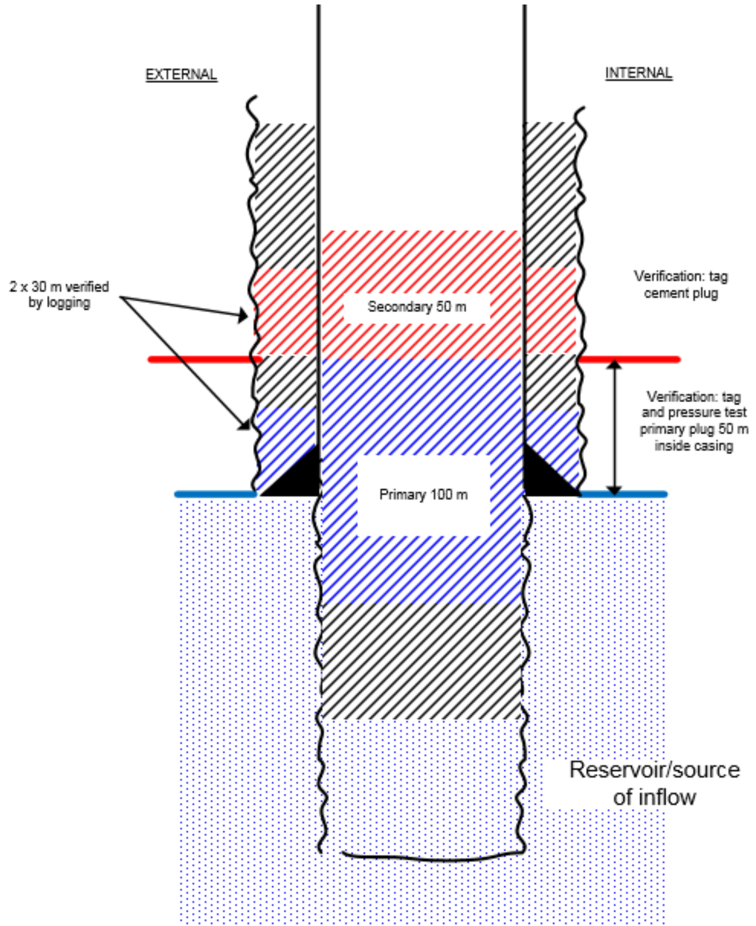


Figure 9 Permanent abandonment with two back to back cement plugs [5]

Single cement plug in combination with mechanical plug

Abandonment of a wellbore where a mechanical plug is used in combination with a cement plug is illustrated in figure 10 below. Here one can observe that a pressure-tested mechanical plug serve as a foundation for a single cement plug, which acts both as primary and secondary barrier. The internal continuous cement plug needs to be verified by tagging. This is done by tagging the cement plug, by drilling into cement.

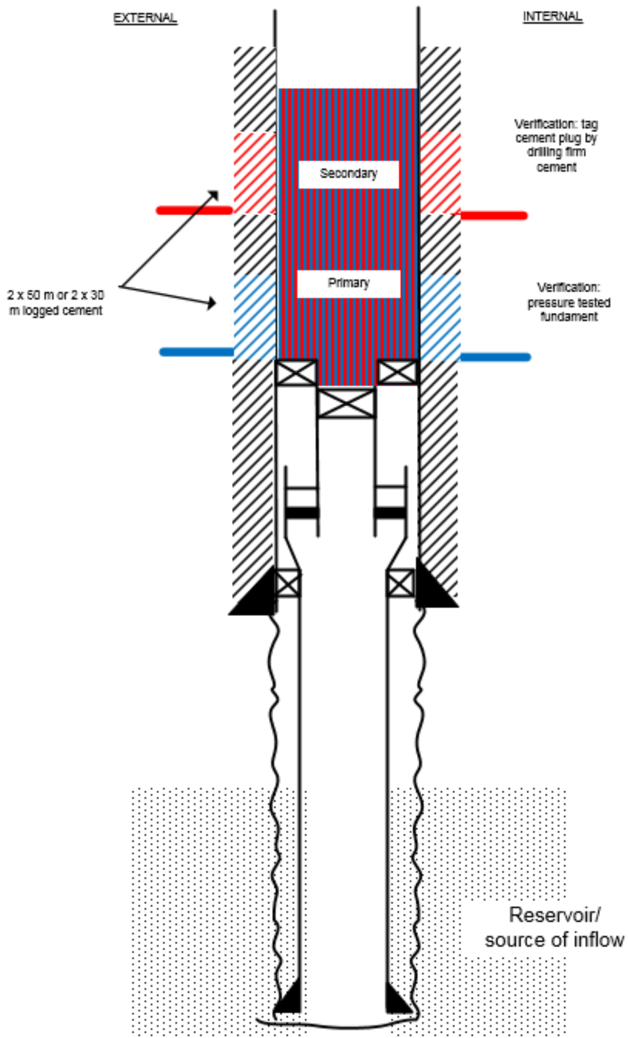


Figure 10 Permanent abandonment, single cement plug with mechanical plug foundation [5]

Tubing stump left in hole

Figure 11 shows an example of abandonment of a wellbore by setting a primary cement plug above the reservoir, and a secondary cement plug within the tubing and tubing annulus. When completion tubulars are left in the well and WBEs are installed in the tubing and annulus, the position and integrity of these **shall** be verified:

a) *"The casing cement between the casing and tubing **shall** be verified by pressure testing.*
b) *The cement plug (inside tubing) **shall** be tagged and pressure tested [5]."*

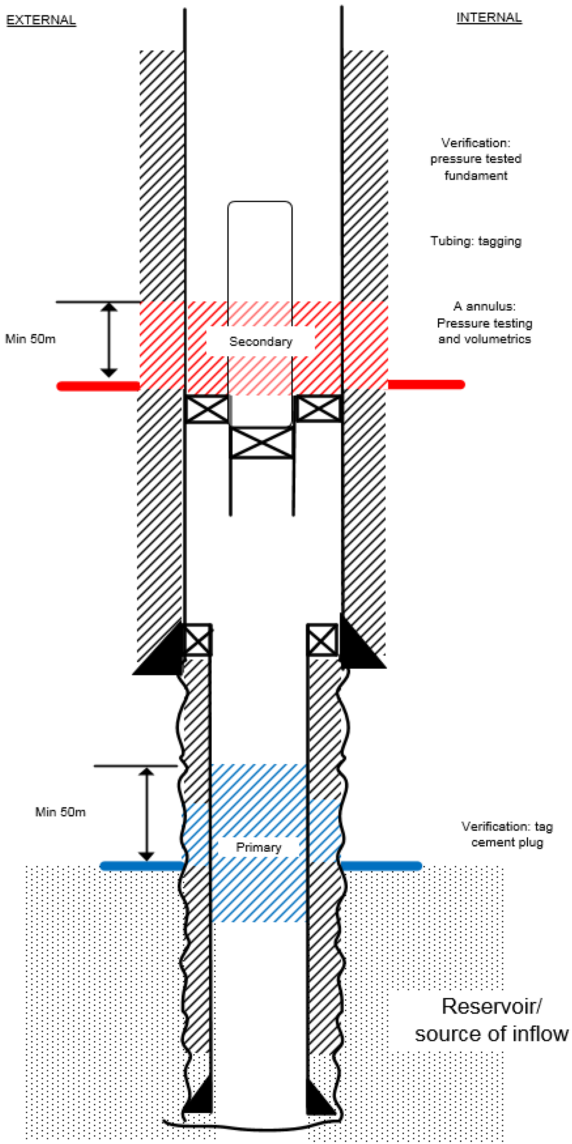


Figure 11 Permanent abandonment, with tubing stump left in hole [5]

2.4.2.4 Verification of well barrier elements

In section 4.2.3.5 one can find the requirements for verification of WBE. It is stated that when a WBE has been installed, its integrity **shall** [5]:

a) *Be verified by means of pressure testing by application of a differential pressure; or*

b) *When a) is not feasible, be verified by other specified methods.*

*WBEs that require activation **shall** be function tested.*

*A re-verification **should** be performed if:*

c) *The condition of any WBE has changed, or;*

d) *There is a change in loads for the remaining life cycle of the well (drilling, completion and production phase).*

Verification of cement plug

Cement is the conventional plugging material used as a WBE when permanently abandoning the well. This is due to it being relatively cheap, easily accessible and, to a large extent, it fulfilling the requirements of permanent well barrier as stated in section 2.4.2.1. Some important criteria to highlight related to verification of cement plugs are:

- Cased hole **should** be tested either in the direction of flow or from above
- The plug installation **shall** be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
- For an open hole plug, its position **shall** be verified by tagging. An open hole cannot be pressure tested due to possible formation fracturing.
- A cased hole plug **shall** be verified with tagging. In addition it **shall** be pressure tested, with two requirements: a) pressure tested 70 bar above estimated leak off pressure below casing/potential leak path, or 35 bar for surface casing plugs; and b) not exceed the casing pressure test and the casing burst rating corrected for casing wear.
- If the cement plug is set on a pressure tested foundation, a pressure test is not required (impossible to verify if it is the mechanical foundation or the plug that holds). It **shall** be verified by tagging".

Verification of casing cement

Cement in the annulus has to be verified to approve the plug. It is required that the length **shall** be verified through logs or using record from the cement operation like volumes pumped, returns during cementing, etc. The cement sealing ability **shall** be verified through a formation integrity test when the casing shoe/window is drilled out.

2.4.2.5 Removing equipment above seabed

Removal of equipment above seabed is the last stage of the decommissioning phase, and is beyond the objective of this thesis. But, in short, NORSOK D010 states that [5]:

- *"For permanent abandonment wells, the WH and casings **shall** be removed below the seabed at a depth which ensures no stick up in the future.*
- *Required cutting depth **shall** be sufficient to prevent conflict with other marine activities. Local conditions such as soil and seabed scouring due to sea current **should** be considered. For deep water wells it may be acceptable to leave or cover the WH/structure.*
- *The location **shall** be inspected to ensure no other obstructions related to the drilling and well activities are left behind on the sea floor".*

3 Plug and Abandonment

This chapter will provide an overall understanding of what P&A is, and describe a general P&A operational sequence, as well as the two types of vessels normally used for these operations. Further, some of the main challenges experienced on the NCS will be identified.

3.1 P&A in Norway

Norway has a relatively short history as an O&G nation with the first discovery on Ekofisk in 1969, and the first production from the field starting in 1971. Subsequently, a number of major discoveries such as Statfjord, Gullfaks, Oseberg and Troll were made, as demonstrated in the timeline below.

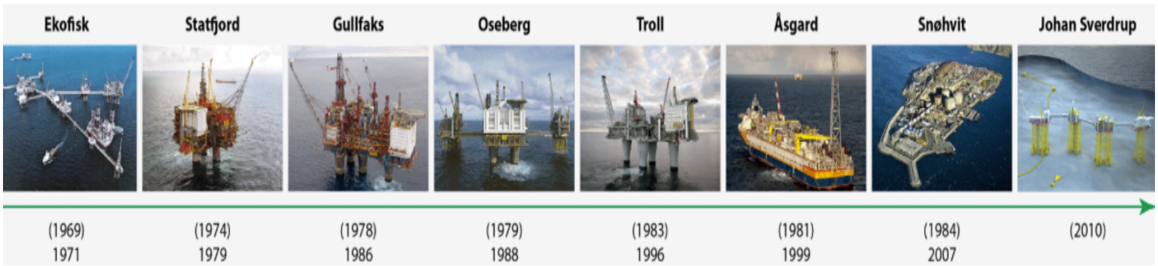


Figure 12 Historical timeline, year of discovery and first oil produced [13]

Several of these major fields have produced for almost half a century and the production rates are now in decline. A new phase is being encountered in petroleum activities in Norway, where we will see a large amount of production wells reaching the end of their lives. The industry is facing what is referred to as a "Plug Wave" [14]. This has led to a growing attention to P&A on the NCS during the last decade.

A P&A forum (PAF) was established in 2009 to promote development of solutions to the current and upcoming P&A challenges on the NCS. PAF arranges annual workshops for the exchange of experience. The main purpose is to present the latest status and encourage the industry to resolve these challenges with robust and efficient technical innovations [15]. Today, P&A represents a significant and increasing liability for O&G companies and limits their ability to optimize their portfolios. The technology development within oil recovery and subsea installations has been a Norwegian success history, while innovative technology within P&A (decommissioning) market has more or less stagnated. Present solutions are very expensive, and this has led to a growing market within P&A services.

Studies executed by Øia and Spieler show that there are currently 352 wellbores ready to be P&A today at the NCS, with 2545 wellbores being ready at some point in the future [16]. Using fifteen rigs full-time, it would take forty years to permanently P&A all these wells and expected future wells on the NCS. With current rig rates and the solutions available today, this can be estimated as amounting to 876 billion NOK [17], which is approximately 16 % of the Norwegian pension fund.

3.2 P&A phases

Based on Oil and Gas United Kingdom (O&G UK) *Guideline on Well Abandonment Cost Estimation*, well abandonment operations can be divided into three different phases to indicate the work scope [18]. These are reservoir abandonment, intermediate abandonment, and WH and conductor removal.

Phase 1: **Reservoir Abandonment**

During the reservoir abandonment phase, the 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. This phase is completed when the reservoir is fully isolated from the wellbore.

Phase 2: **Intermediate Abandonment**

In this phase, the liners are isolated, milling and retrieving casing operations are performed and the barriers against the intermediate zones are set. The tubing may be retrieved if not already done in phase 1. The phase is considered to be finished when all the plugging operations have been completed.

Phase 3: **Wellhead and conductor removal**

The last phase includes retrieval of WH, conductor, shallow cuts of casing string and cement filling of craters. Phase 3, and the abandonment operation, is completed when no further operations are required for the well.

3.3 Conventional P&A Operation

There is a large variety of well designs depending on different factors as condition of the well, top of cement, number of reservoirs, geology etc., and so the P&A operation of the different wells will vary. However, some general principles in the operational procedure will be presented in this section.

The main steps of a P&A operation can be presented in the following order:

1. Well diagnostic
2. Well kill
3. Pull XMT and run blow out preventer
4. Cut and pull tubing
5. Logging
6. Establish primary and secondary barrier
7. Cut and pull intermediate casing
8. Establishing surface barrier
9. Cut and retrieve WH

3.3.1 Well diagnostic

Before starting on the P&A operation it is important to know the condition of the well and the potential inflow from both the reservoir and overburden. According to NORSOK D-010 all sources of inflow shall be identified and documented, including shallow sources of inflow [5].

Many of the wells on NCS are old and have a lack of available data. The original well design is known, but the accessibility and condition may have changed over the years. The current state of the well will, to a large extent, form the basis for the P&A design. The accessibility to the reservoir, reservoir and fracture pressure, are used for calculating and choosing the setting depth of the primary and secondary barriers. Well diagnostics are usually performed with a light well intervention vessel (LWIV) using wireline (WL).

3.3.2 Kill the well

A fully-producing well, known as a live well, should be killed before entering. A well kill is an operation of placing a heavy density fluid into the wellbore to stop the well from flowing, or having the ability to flow into the well [19]. There are different methods of killing the well, but the most common practice is known as bullheading. In a bullheading operation, pumps are rigged up to force the production fluids backwards into the reservoir. A way of doing this is to start with pumping brine down the production tubing with a high pump rate forcing the production fluid back into the formation illustrated in figure 13. The injection pressure must be larger than the WH pressure, but the upper limit is determined by the criterion that one must not exceed the casing or tubing burst pressure, or fracture the formation during the operation.

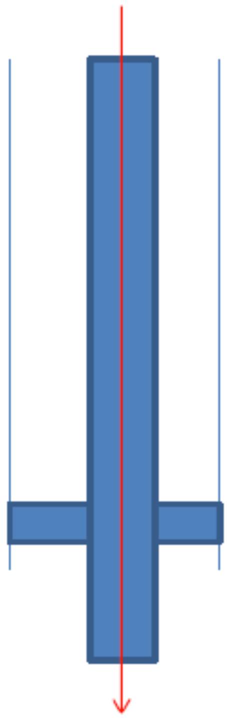


Figure 13 ”Bullheading” operation [20]

The pumping is continued until all the HC has been displaced into the formation and the tubing is filled up with fluid of sufficient density to contain the reservoir pressure. The WH pressure will then vanish and intervention operations can be conducted [21].

3.3.3 Pull XMT tree and run Blow Out Preventer

In order to have well control the Xmas tree (XMT) is removed, and the blow out preventer (BOP) is installed. The operational procedure for when the XMT shall be removed depends on the type of XMT. When a vertical XMT (VXMT) is installed, the well is secured with primary and secondary barriers before removal of the VXMT [5]. In situations with a horizontal XMT (HXMT), a deep-set plug is installed before removal of the HXMT, as is the situation on the Gjøa field. In this case, prior to pulling the production tubing, the kill fluid is displaced through the production tubing and A-annulus. Then a shallow plug is set inside the production casing after tubing retrieval, and before removal of HXMT [5].

3.3.4 Pull tubing

Pulling the tubing and the upper completion is a heavy operation and is typically done by a MODU with machinery that can handle high loads. In some cases when dealing with long wells it might be impossible to pull the entire tubing. Then the tubing is cut and the lower part of the tubing is left in the reservoir. In most cases the tubing needs to be pulled for various reasons e.g. requirement to log behind the intermediate casing, or the removal of control lines as they can be a potential leak source [5]. The normal procedure is to cut the tubing above the production packer, remove the XMT, install the BOP and then pull the tubing.

3.3.5 Logging

Logging is an important part of the P&A operation procedure to verify that the cement behind the casing is of good-quality. If the well diagnostic shows that the wellbore is intact, and there is good communication with the reservoir, WL can be used. The UltraSonic Imager Tool (USIT), Cement Bond Log (CBL) and Variable Density Log (VDL) are run prior to setting the barriers in order to confirm the annular seal of cement behind the casing. If the cement is good-quality, it can be used as part of the permanent barrier. If this is not the case, a milling job might be required, and this is time consuming and not preferable.

3.3.6 Establish primary and secondary barrier

When the tubing is cut and retrieved, the next step is to install the primary and secondary barriers against the reservoir. If the annulus cement (cement behind the casing) is verified and proved to be good-quality, cement can be installed inside the casing.

3.3.7 Cut and pull intermediate casings

Since the intermediate casings are not usually cemented all the way to the top, they have to be removed before setting the surface plug to establish a full cross section barrier. Casings are retrieved mainly for two reasons: to establish a full cross section barrier and to get access for logging, since current logging technology is not able log through multiple casings.

3.3.8 Establishing surface barrier

The surface permanent plug is then installed. When casing cement is of good-quality, it is sufficient to set a surface plug inside the casing.

3.3.9 Cut and retrieve wellhead

The last phase of a P&A operation is to cut and retrieve the WH. According to NORSOK standards, the WH and casings shall be removed below the seabed at a depth that ensures no protrusion in the future. Required cutting depth shall be sufficient to prevent conflict with other marine activities. Local conditions, such as soil and seabed scouring due to sea current, should be considered. For deep-water wells, i.e., in water depth exceeding 600 m, it may be acceptable to leave or cover the WH/structure [5].

A typical Ekofisk P&A sequence from ConocoPhillips is presented in figure 14 below. Blue and red are used respectively to illustrate the primary and secondary barriers throughout the operation. The representative Ekofisk P&A requires five plugs, meaning that there are probably two sources of inflow to be considered.

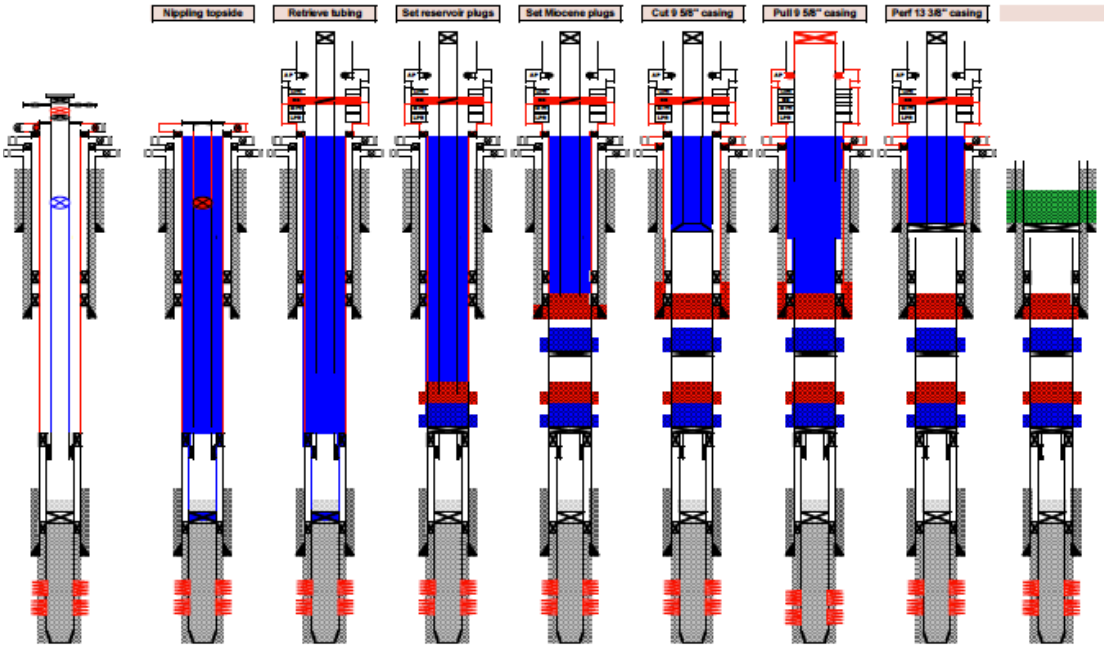


Figure 14 P&A operational sequence on Ekofisk [22]

3.4 Vessels used for P&A operations

When performing a P&A operation, it is necessary to access the well at many different stages. This is known as well intervention, and can be defined as the ability to safely enter a well with well control for the purpose of doing a number of tasks other than drilling [23]. Interventions normally fall into two general categories: light or heavy intervention. Light well intervention is typically done without a riser by smaller monobore vessels. Heavy intervention is done by larger mobile offshore drilling units (MODUs), in combination with a marine riser or work over riser (WOR).

3.4.3 Mobile offshore drilling unit

Well intervention has historically been performed by MODUs. The traditional definition of MODU is associated with the deployment of drilling rigs, and can generally be divided into three major types of units [24];

- Jack-ups
- Semi-submersibles
- Ship-shaped

These are large vessels that can perform all type of P&A operations, such as pulling up production tubing and cutting and retrieving casings. The MODUs have high cost, and are best suited for drilling and heavy workover operations. Eliminating, or at least reducing the use of these vessels can achieve significant cost savings.

Figure 15 Transocean searcher, used for drilling the wells on Gjøa [25]

The conduit that provides a temporary extension of a subsea well to the MODU is called a drilling riser. Risers can be subdivided into low-pressure (marine riser) and high-pressure risers (workover riser). A marine riser is a large, vertical pipe, usually 21", between the BOP and rig floor. Since the BOP is located below it, marine risers do not need to contain full well pressure [26]. A WOR is a smaller, thick-walled pipe used with surface BOPs. Because the BOP is at the surface, the WOR must contain full well pressure. The WOR system that was previously used when drilling the wells on the Gjøa field can be found in Appendix A.

3.4.1 Light well intervention vessels

The aspiration for the industry should be to reduce the use of MODUs for P&A through increased use of light well intervention vessels (LWIVs). These types of vessels are smaller sized, typically monohull supplier type vessels performing intervention on live subsea wells without the use of a riser system to the surface: an example, that of Island Constructor, is shown in figure 16.

Use of LWIVs releases rig time for drilling and completing new wells to sustain oil production. They are more mobile than MODUs allowing them to wait until the weather forecast is more suitable for the whole operation period. Furthermore, these vessels have a lower daily cost compared with semi-submersible rigs, which can aid in reducing the cost of P&A [27]. There are, however, a number of operating limitations compared to use of a drilling rig:

- No marine riser hence no circulation path. This means that one cannot monitor the fluid level, and fluid cannot be used as a barrier during operations.
- Difficulty pulling the completion tubing or casing strings.
- Limited to WL and potentially coiled tubing deployed tools.
- Weather limitation.

Figure 16 Showing the LWIV, Island Constructor [28]

3.5 Challenges of P&A Operations in North Sea

The process related to P&A is technically-challenging, with complicated and time-consuming, high-cost operations. P&A is a multifaceted operation and introduces several challenges, some of which will be addressed in this section.

3.5.1 Weather

Weather is a big issue for any well operations performed on the NCS. Logistics, mobilization, operation, equipment limitation, and much more depend on weather conditions [29]. During well activities bad weather conditions could force suspension and therefore delays of the operation. This is commonly known as Waiting on Weather (WOW), and a lot of time and money can be wasted on this. It is difficult to avoid WOW, but the choice of vessel and season of operation are parameters that can reduce delays. Analysis done by Valdal showed that LWIV have more WOW compared with semi-submersible ships, mainly because of vessel size, and that summer is statistically the best time for a P&A operation due to lower wave heights than the rest of the year [30].

3.5.2 Abnormally-pressured zones in overburden

Shallow water flow (SWF) and shallow gas can be an expensive problem for drilling exploration wells, and is also an issue when planning the abandonment of the wells on Gjøa. SWF is a phenomenon that may be a result of different mechanisms, but usually occurs when fluids under greater than hydrostatic pressures are present within highly permeable sands, with very little consolidated overburden [31].

Drilling operations encountering these zones, without securely placed casing, are subject to high risk where fluids will flow out of the formation and up the borehole and drill string. Drilling operations are vulnerable at shallow depths below the sea floor before casing is set, and BOP is installed.

According to the regulations, abnormally-pressured formations with the potential for flow to surface have to be plugged with two well barriers in the abandonment stage [5]. This can be a very complicated operation since it adds one additional casing string removal in the overburden, and two additional barriers must be in place to isolate this zone.

3.5.3 Milling

When abandoning a well, permanent plugs have to be put into place, sealing the wellbore in all directions, including all annuli horizontally and vertically [5]. In many wells the position in the casing where the plug will be placed is not cemented, or the cement is bad-quality. In order to place a plug that meets the requirements, communication is needed from the wellbore to the annulus. The conventional way of doing this is to section mill the required length of the casing, perform a clean-up run, underream the open hole and emplace a balanced cement plug [32]. These operations are time consuming and difficult to execute safely and effectively.

There are several challenges related to the milling process. Section milling fluids must be able to keep the open hole stable, and have sufficient viscosity to suspend and transport swarf and debris to surface. The required fluid weight and viscosity may cause equivalent circulation density values that exceed the fracture gradient, leading to [32]:

- Losses while circulating
- Swabbing
- Well control problems
- Poor hole cleaning
- Pack off around bottom hole assembly

There are also some health, safety and environmental (HSE) challenges present due to the handling and disposal of the generated swarf and debris. Swarf is metal filings or shavings removed by a cutting tool, and swarf handling is regarded as one of the main challenge in traditional milling. The metal returns have sharp angular surfaces which can damage the BOP and surface equipment. Personal protective equipment should be worn to protect hands and eyes [32].

3.5.4 Available technology

The process of conventional P&A, including milling, is time consuming, costly and poses several challenges. In the Norwegian sector of the North Sea, there are more than 2545 wells ready for P&A in the future [16]. While the technology in extractive O&G from reservoir has evolved considerably in recent decades, there have been few evolvements within P&A. The operating companies are searching for new innovative and technical solutions to meet the challenges represented by P&A operation. The overall goal for the petroleum industry is to make the P&A operation as cost-effective as possible, without compromising the quality and/or safety.

3.5.5 Cutting and removal of casing

The cutting and removal of a casing string is a very technically-challenging part of an abandonment operation. A conventional P&A operation is usually performed by cutting and pulling the casing in order to fulfil the requirement of a cross sectional barrier. It might also be necessary to remove casings for establishing the open hole to surface barrier, or for setting the barriers for reservoirs in overburden formations. The casing string could be stuck due to old cement and settled particles in the annulus, and multiple cut and pull operations may be necessary to free the casing. If the casing remains stuck, section milling may be necessary. Another reason for removing the casing is due to limitations with current logging technology.

3.5.6 Logging

The cement behind the casing, known as casing cement, has to be verified as an element of the barrier plug. The most common method used to verify the quality of casing cement is by logging. The ability to log cement and its isolation properties through pipes/casings is an important contribution to providing understanding and confirmation of the existence of good cement behind the casing area. Current logging technology is not capable of logging through multiple casings, meaning that one must remove all inner casings in order to verify the quality of the cement behind B- and C-annulus.

Data retrieved from the logs need to be reliable, since the cement will be part of a permanent barrier that will isolate the reservoir for "eternity". Interpretation of the data retrieved depends largely on subjective interpretation, and this may lead to considerable uncertainty when using logging instruments.

3.5.7 Removal of control lines

When performing P&A it is desirable to avoid pulling the tubing from the well. If the tubing has control lines attached, especially in the deeper regions where isolation plugs are set, this could lead to difficulties. These completions, with tubing and control lines attached, are called intelligent completions and were introduced to remotely monitor and control wells. The control lines can cause challenges when cementing the A-annulus past the cable clamps, and the control lines themselves may constitute a potential leak path for the HC. It is required that the control lines be removed from the location of the barrier plugs [5]. The only way of doing this, with the technology currently available, is to remove the entire production tubing, which is a time consuming and difficult part of P&A.

3.5.8 Wellhead fatigue

Fatigue capacity of a system can be defined as the system's ability to accommodate cyclic loading before experiencing failure. During recent years, fatigue loading on subsea WH has been increasing due to the complexity and duration of offshore activities. Additionally, the use of larger and heavier BOP stacks has grown significantly [33]. These factors have led to an increase of fatigue loads experienced by the WH and casing system.

Analysis of a connected riser and well system is both complex and multidisciplinary, as schematically illustrated in figure 17. During all riser-connected operations, the well system is subjected to fatigue loading induced by environmental forces such as [34]:

- Waves
- Current
- Wind
- Rig motions

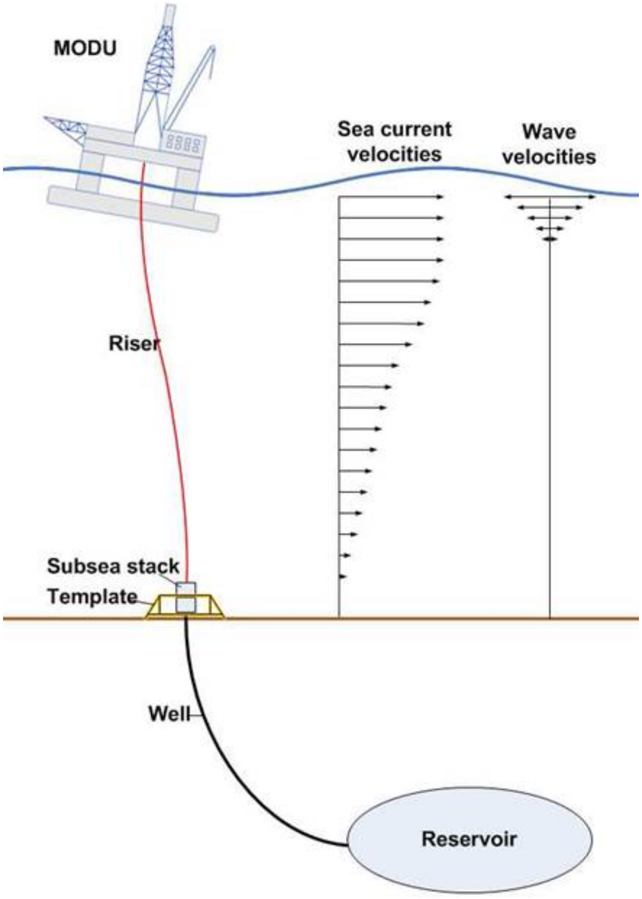


Figure 17 Overview of forces on subsea stack [34]

P&A is the last phase of the "life cycle of the well", as shown in figure 18, and operations usually involve use of multiple stack-ups, which causes fatigue damage rate to vary. P&A operations include pulling the XMT, tubing, casings etc. and setting a number of zonal isolation cement plugs as already mentioned. These operations may take several weeks depending on the complexity of the well system. ENGIE E&P Norge is therefore performing a WH fatigue analysis to estimate the accumulated fatigue damage before starting on the P&A operation.

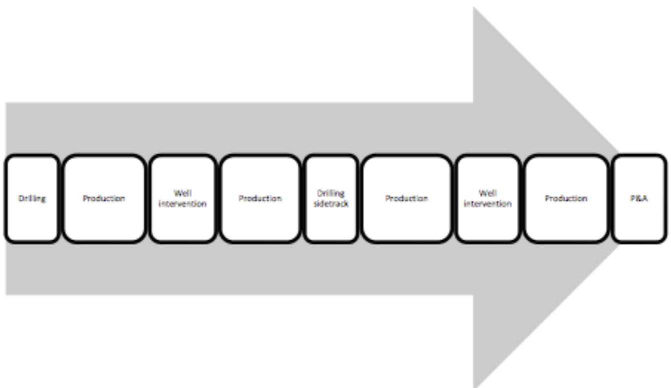


Figure 18 Life of well with re-use of wellhead [35]

4 The Gjøa field

The Gjøa field was discovered in 1989 by Hydro. The license is located in blocks 35/9 and 36/7 in the Norwegian North Sea, see figure 19, and is owned by ENGIE E&P Norge AS (operator, 30%), Petoro (30%), Wintershall Norge AS (development operator, 20%), A/S Norske Shell (12%) and DEA Norge AS (8%). The first producing well was finished in November 2010, and was drilled by the semi-submersible rig, Transocean Searcher.

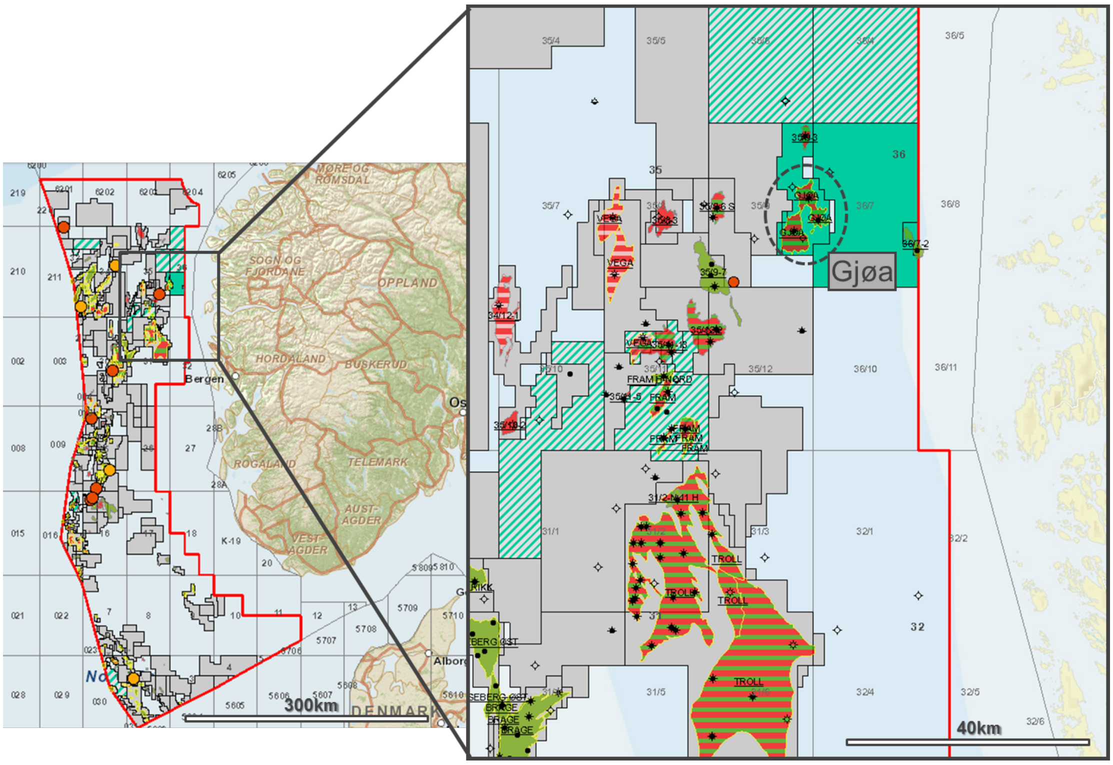


Figure 19 Location of the Gjøa field [3]

Gjøa is a combined O&G field, and initially estimated to contain 82 million barrels of oil and condensate and 40 billion cubic metres of gas [36]. The field has been developed through four subsea templates, and it has a total of seven oil producers and four gas producers. Template B, C and D are in approximately the same location, see figure 20. A total of two gas wells and seven oil wells were drilled from these three templates. One gas well and two oil wells were drilled from template E located between the P5 and P7 segment, while one gas well, F1, was drilled as a satellite well from P1 segment, as shown in figure 22.

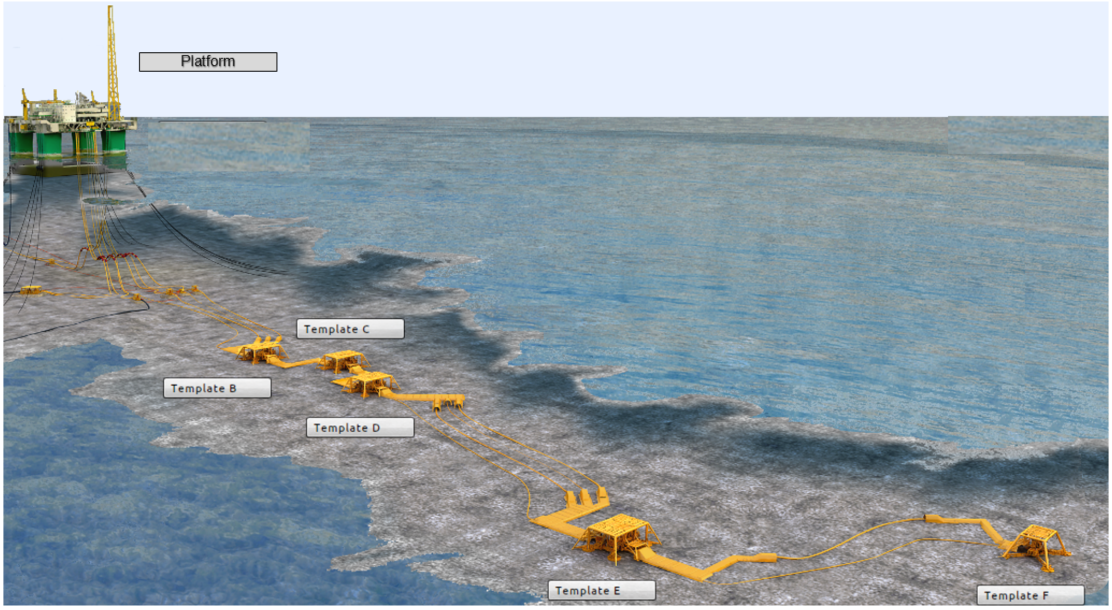


Figure 20 Field layout [37]

The rich gas (contains condensate) extracted from the reservoir is exported through the FLAGS pipeline to St. Fergus in Scotland, and the oil is exported through the TOR2 pipeline to the Mongstad power plant north of Bergen, Norway. The power used to run the Gjøa production platform is, as the first platform in the world [38], being transported through an undersea cable from Mongstad, reducing carbon dioxide emissions from the field. The water depth in the area is in between 350-370 metres mean sea level (MSL) [36].

Summarized:

- Four 4-slot templates
- One single satellite template in north
- Power cable from Mongstad
- Oil export in Tor II pipeline to Mongstad
- Gas export to Flags UK
- Vega tie in to Gjøa

4.1 Geology

Gjøa field is located in the northernmost part of the Horda Plateau, on the east side of the northern Viking Graben. The location is ~50 km northeast of the Troll field and ~40 km northeast of the Fram field as showed in figure 21. The upper

Jurassic reservoir has similarities to the adjacent Fram and Troll field. The field was discovered in 1989 by the 35/9-1 exploration well, and further appraised by the 35/9-2 and the 36/7-1 wells.

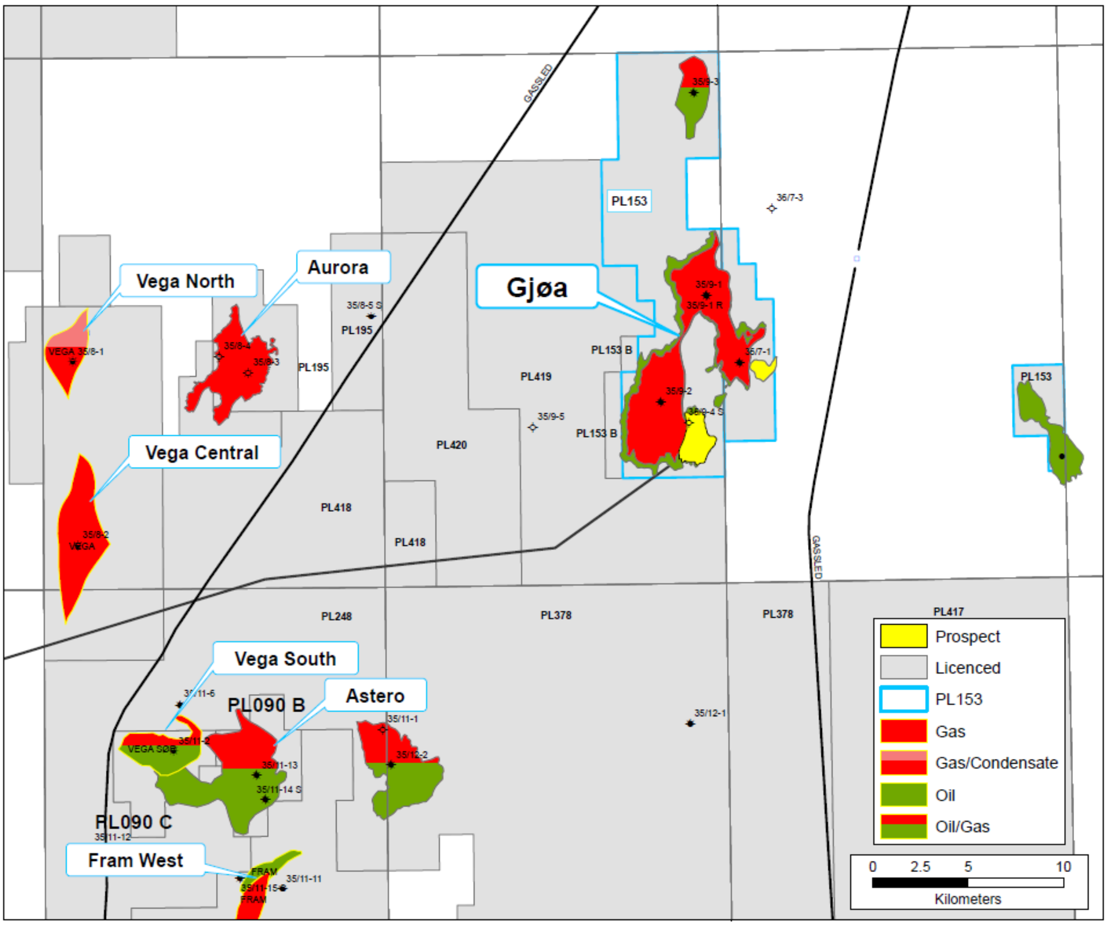


Figure 21 Gjøa is well positioned to become the central hub for new developments [3]

The field can be divided into seven fault controlled segments (P1-P7). The P2/P3 segment forms one tilted fault block in the southwest of the Gjøa Field. A southwest to northeast striking fault splits the P2/P3 segment into two compartments. The P2/P3 structure is bounded to the west by a North-South striking fault, which separates the P4 segment from the P2/P3 structure. The intersection of the late Jurassic- early Cretaceous unconformity with the fluid contacts defines the remaining part of the structure. Locally, this erosional event has removed more than 60% of the upper reservoir section [3].

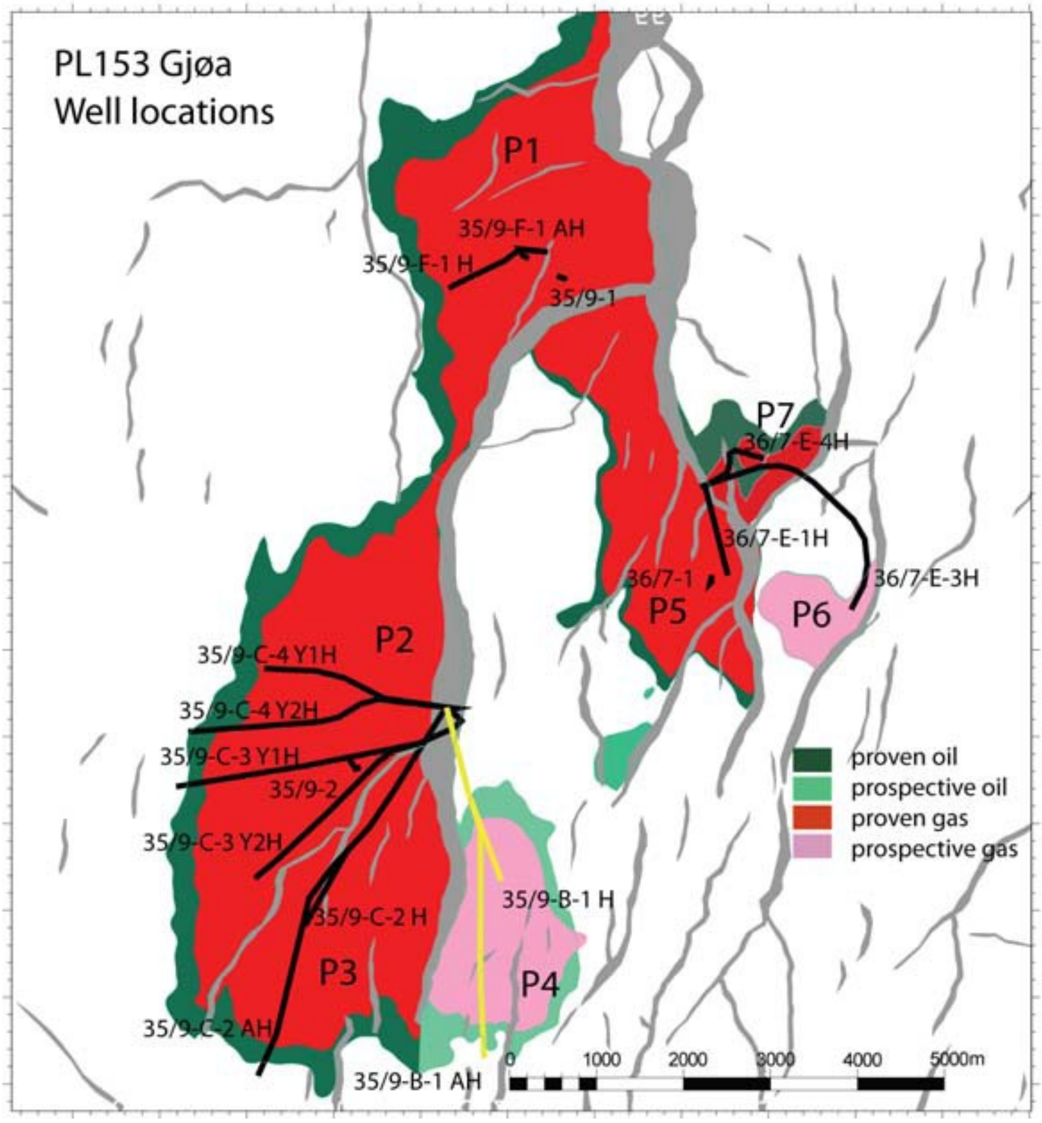


Figure 22 Well locations [3]

4.2 Reservoir

The main reservoirs are the Krossfjord, Fensfjord and Sognefjord formations in the upper Jurassic Viking Group, and consist of alternating sand, silt and shales. The reservoir quality varies from very good to poor, both vertically and laterally [36]. There are both proven O&G deposits in the Sognefjord and Fensfjord formation. In the northernmost part of the field, gas was discovered in Krossfjord formation, and O&G in Middle Jurassic sediments associated Brent and Dunlin Groups as shown in the formation groups' figure 23 below.

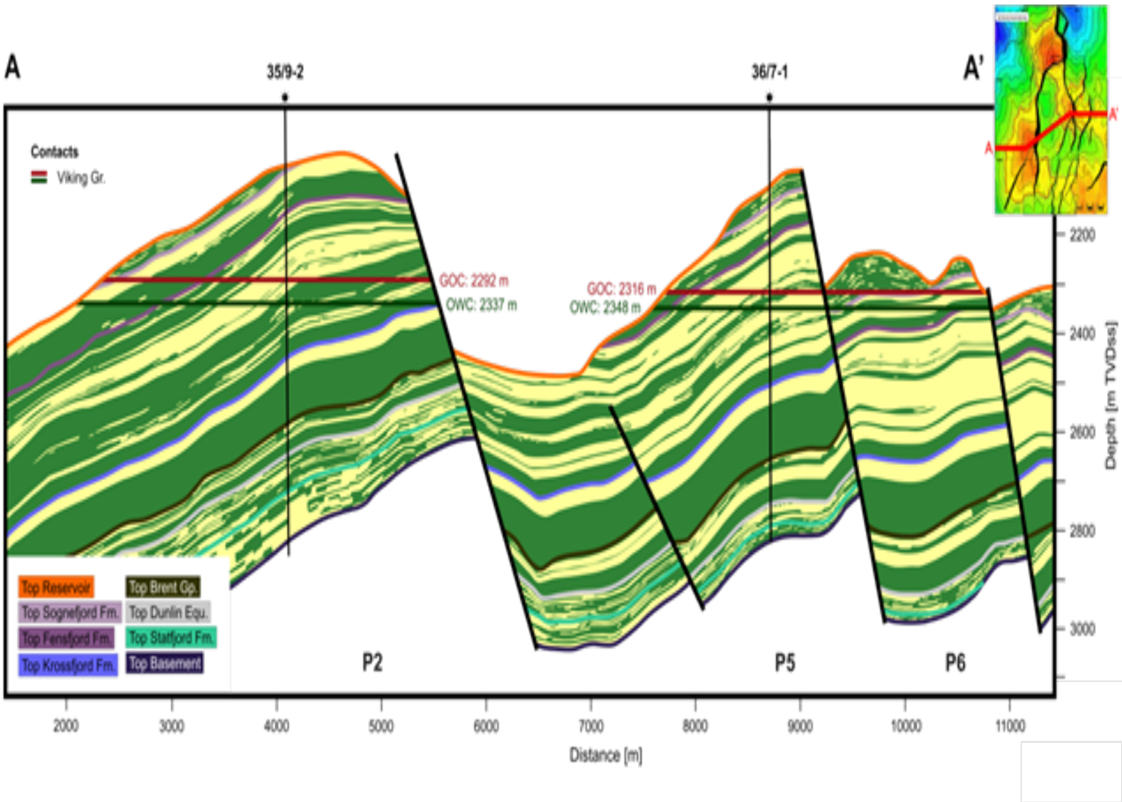


Figure 23 Formation groups [3]

The reservoir pressure was initially hydrostatic, about 235 bar and reservoir temperature 82^{0}C. Reservoir column and fluid contacts vary among segments. Reservoir column extends from about 2000 metres depth to 2348 metres below sea level (deepest proven oil water contact). This gives a gross reservoir thickness of just less than 350 metres. Column distributed on a 30-45 metre thick oil zone, with an overlying gas cap of up to about 300 m gross thickness.

The greatest challenge related to drainage of Gjøa reservoir is extraction of the oil. Reservoir layers dip sharply so that the distance from the oil zone of the **gas respective water** is short seen in figure 24. The total recovery rate is estimated at 21% for oil and 69% for gas.

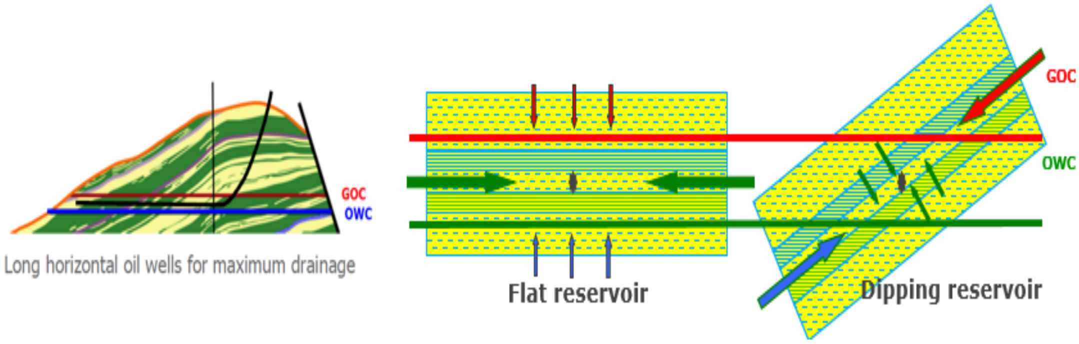


Figure 24 Oil production is a major challenge on Gjøa [3]

4.3 Drilling

The drilling of the first production well started on 19 January 2009. One of four exploration wells in the Gjøa field was abandoned as a result of severe SWF [25]. After initiation of SWF, it turned out to be difficult to kill the well. Because of the likelihood of experiencing similar scenarios drilling the thirteen production wells, measures were taken to avoid this. This involved drilling the 26" top hole section with weighted mud, using Riserless Mud Recovery (RMR).

Excess pressure, called overpressure, can cause a well to blowout or become uncontrollable during drilling. RMR is a dual gradient technology that enables drilling tophole with weighted and engineered mud to prevent SWF and still be able to bring the fluid and cuttings back to the rig.

The RMR system consists of a suction module that is run and installed on the WH. This has a collection chamber where well returns are collected and diverted through a hose to a subsea mud pump. A mud return line allows pumping or lifting the mud and cuttings back to surface before the marine riser is run [39]. This system is illustrated in fig 25.

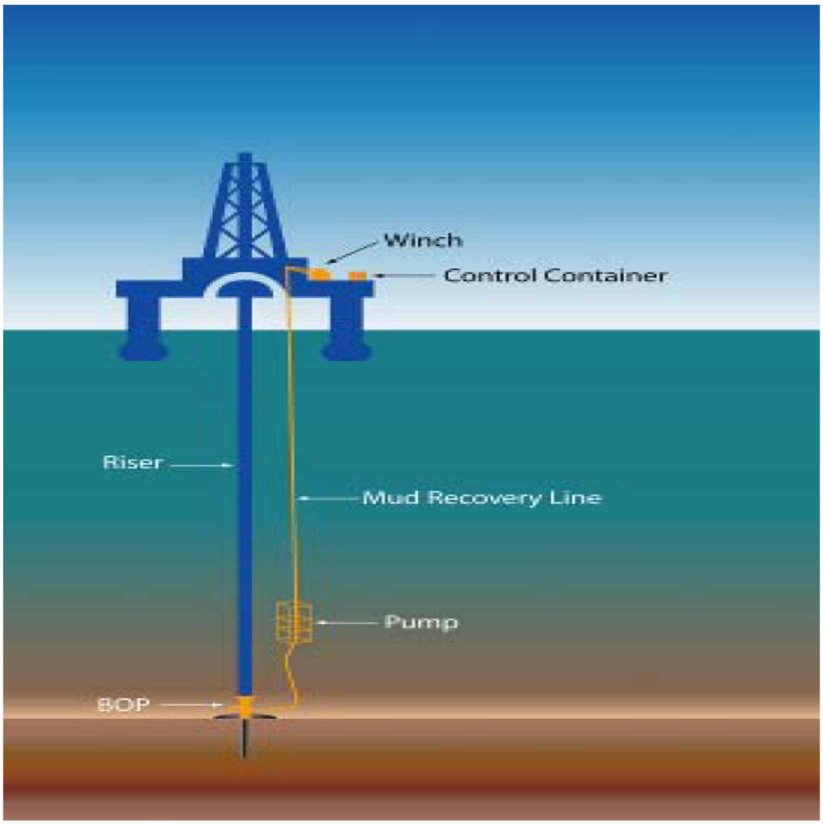


Figure 25 Riserless Mud Recovery system [40]

In this way a "closed loop system" is established. Mud and cuttings are collected at the seafloor and returned to the shakers. The same concept is used for drilling deeper after the riser has been run. Selection of the technology is typically driven by its ability to impact drilling efficiency and safety. The main advantage of the RMR is that engineered drilling fluids can be used for drilling the top hole sections, thereby eliminating discharges of mud and cuttings at seafloor [39]. The technology made it possible to allow setting of the 20" casing deep enough to cover the SWF zone, eliminating an extra liner across the problem zone. The wells on Gjøa consist of casing sizes and approximate depths given in table 3.

Table 3 Casing program and approximate depths of the casing shoe

Outer diameter	Approximately depth	
	Oil well mTVD (MSL)	Gas well mTVD (MSL)
30" Conductor	445	425
20" Casing	1000	1000
13 3/8" Casing	1945	1960
9 5/8" Casing	2260	2100
7" Liner (B-1)	2335	-

4.5 Well Categorisation and Completion

For abandonment of multiple wells, it should be recognized that each well is unique and the well abandonment design should be considered on an individual basis. However, because of the extent of work, the eleven production wells will be categorized into monobore gas wells, monobore oil wells and multilateral oil wells. This is done in order to simplify this thesis, as a thorough study of every well would require a tremendous amount of work. Table 4 below shows the eleven production wells including some important information about shoe depth, top of reservoir and quality of cement.

Table 4 Well overview and casing cement barrier evaluation

Well names	Well ID	Well Production Type	Shoe Depth (m)	Top Reservoir (m)	Primary Barrier (m)	Secondary Barrier (m)	Overall Cement Height (m)	Cement Logged
B-1	35/9-B-1 AHT3	Producer - Oil	2745	2867	104	96	200	Yes
B-2	35/9-B-2 H	Producer - Gas	2646	2642	95,7	114,3	210	Yes
B-3	35/9-B-3 H / HT2	Producer - Oil	3440,8	2650,7	32,1	50	82,1	Not stated in final well report
C-1	35/9-C-1 AY1H, AY2H	Producer - Oil	2890	2165	17	73	90	Yes
C-2	35/9-C-2 AH	Producer - Oil	3142	2706	6	185	191	Yes
C-3	35/9-C-3 Y1H, Y2H	Producer - Oil	2844	2112	13	89	102	Yes
C-4	35/9-C-4 Y1H, Y2H	Producer - Oil	2854	2160,5	11,5	23	34,5	Yes
D-1	35/9-D-1 Y1H, Y2H	Producer - Oil	2928	2244	14	195	209	Yes
D-3	35/9-D-3 H	Producer - Gas	2307	2289	21	341	362	Yes
E-1	35/9-E-1 H	Producer - Gas	2438	2465	95	132	227	Not stated in final well report
F-1	35/9-F-1 H, AH	Producer - Gas	2140	2139	94	277	371	Not stated in final well report

The casing cement job was logged with USIT, CBL and VDL logs during drilling. Logging of 13 3/8" casing and 9 5/8" liner is, according to the final well report (FWR), interpreted as having confirmed good barrier cement in the interval where it is planned to place the primary and secondary barriers. Table 4 above shows the overall good-quality cement of the wells, with the colour green indicating that this is in accordance with the regulations stipulating a minimum length of 30 m logged casing cement. It should be noted that well C-4 does not have the required casing cement height in accordance with NORSOK-rev 4 requirements, but was in consistent with rev 3, which was applicable at the time of drilling the wells so dispensation will most likely be given.

All the production wells are installed with HXMT and completed with 7" tubing. The HXMT is installed on top of the WH, before the tubing and tubing hanger are installed inside the tree. The main benefit for the HXMT is the possibility of replacing the tubing without retrieving the HXMT in the event of tubing leakage etc. However, for P&A purposes the tubing hanger and tubing need to be retrieved before the HXMT can be retrieved. Cross sectional schematics of the WH and HXMT can be found in Appendix B.

Monobore gas well

There are four monobore vertical/slanted (up to 46^0) gas wells in field:

- B-2, D-3, E-1, F-1

Standard components:

- Open hole gravel pack and screens
- Plug/Isolation Valve (either glass plug or full bore isolation tool)
  - Opened during clean-up and remains open
- Single cycle tool
  - Closed during completion and remains closed
- Rupture disc
  - Safety measure to avoid damaging casing when well heats up
- Production packer
- Downhole pressure/temperature gauge
  - Located ~100 m vertically above reservoir
  - Monitors tubing and annulus
- 7” production tubing
- Downhole Safety Valve
- HXMT

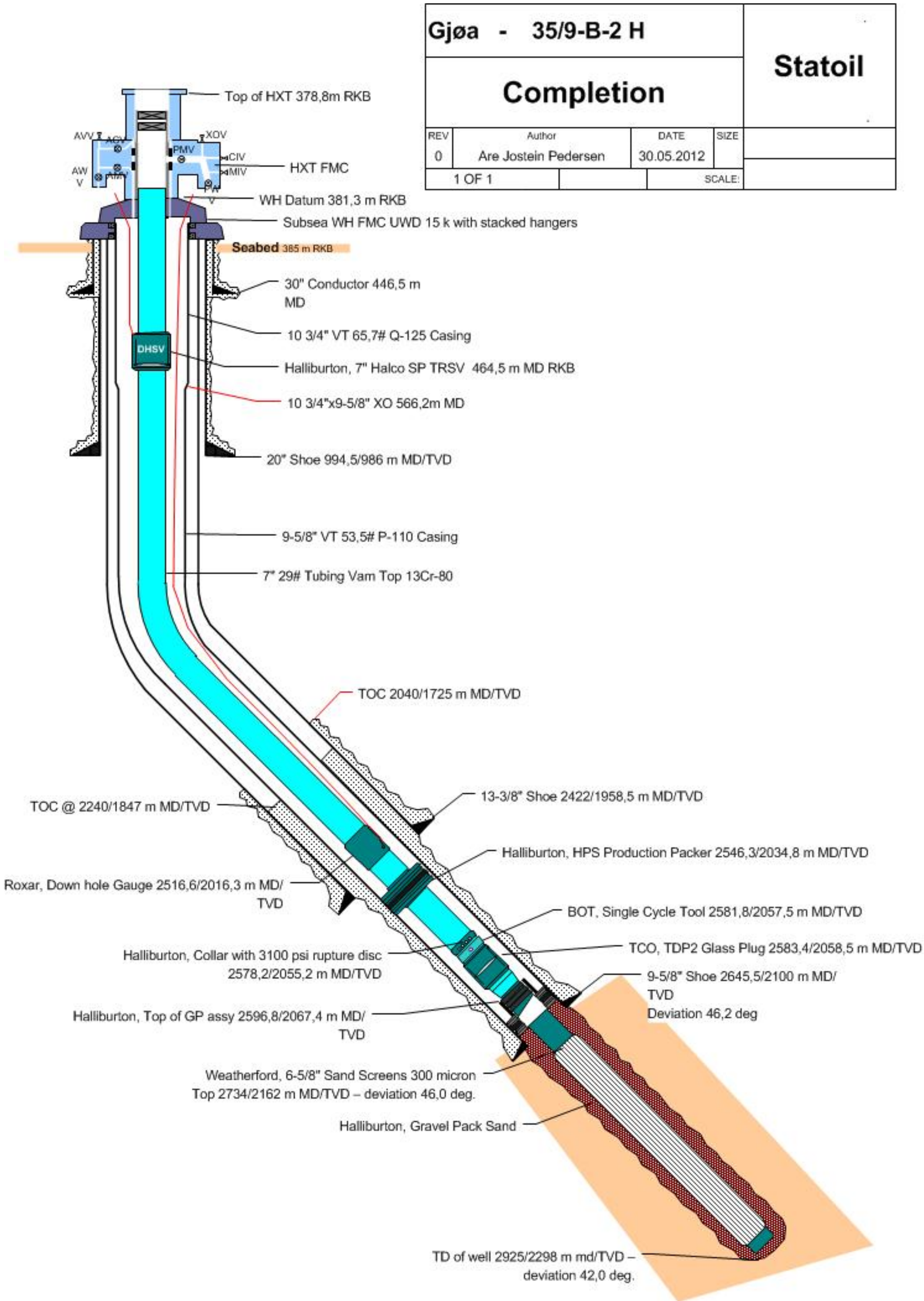


Figure 26 Monobore completion gas well [41]

Monobore oil well

Three monobore horizontal oil wells in field:

- B-1, B-3, C-2

Standard components:

- Standalone screens
  - Some wells also have blanks sections and/or swellable packers in the reservoir section
  - B-1 has smaller screens than all other wells due to drilling problems
- Isolation Valve
  - Opened during clean-up and remains open
- Single cycle tool
  - Closed during completion and remains closed
- Production packer
- Downhole pressure/temperature gauge
  - Located ~100 m vertically above reservoir
  - Monitors tubing and annulus
  - Not working on C-2
- 7” Production tubing
- Gas lift valve
- Downhole safety valve
- HXMT

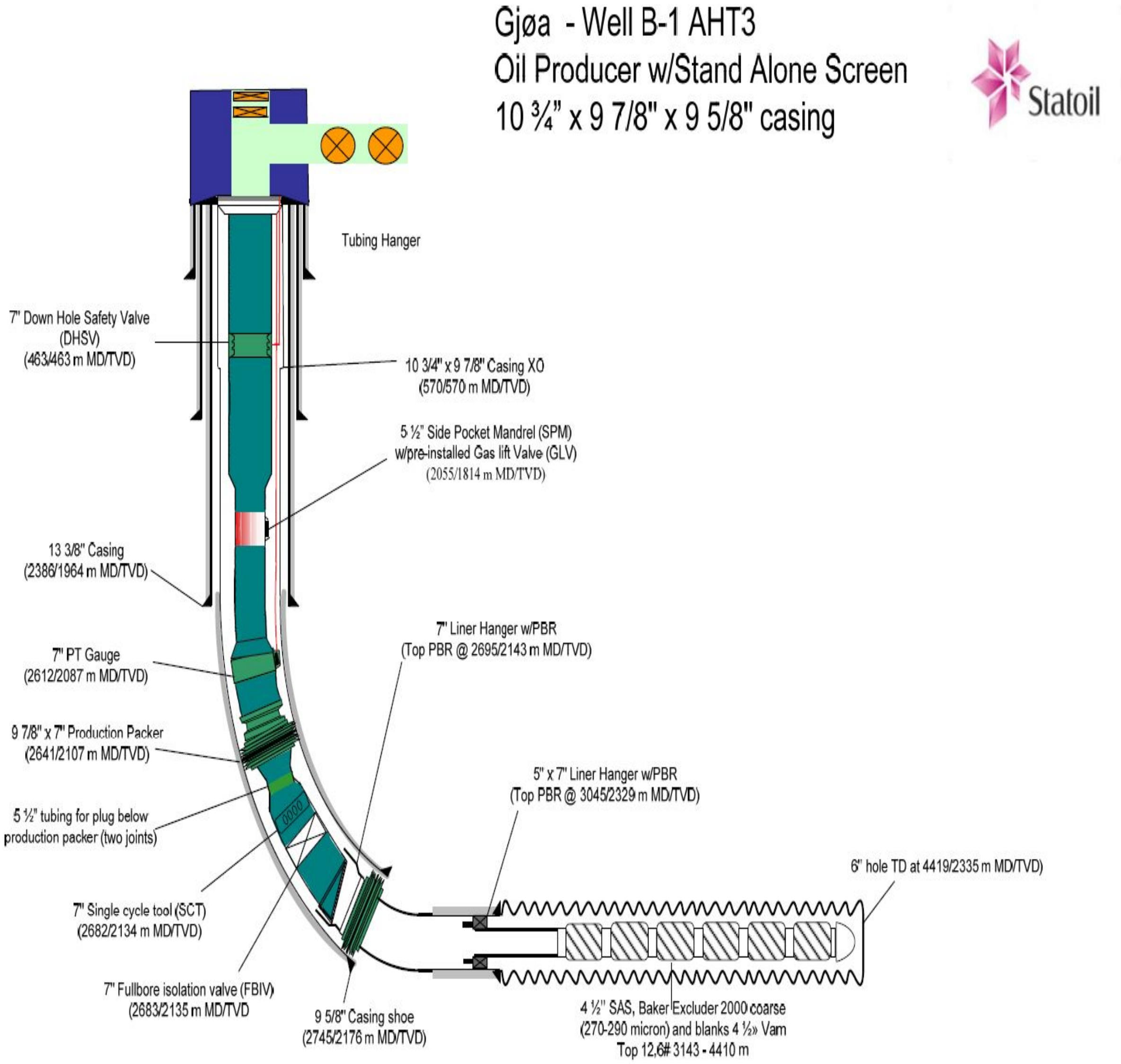


Figure 27 Monobore completion oil well [41]

Multilateral oil well

Four multilateral horizontal oil wells on field:

- C-1, C-3, C-4, D-1
- Two horizontal branches in the reservoir

Standard components:

- Standalone screens
- Multilateral junction

  - Includes Downhole, Instrumentation and Control System (DIACS) valves with pressure/temperature gauges

  - DIACS position indicators (except on C-1 lateral branch)
- Downhole pressure/temperature gauge (tubing only)

  - Located at reservoir depth
- Production packer
- 7” Production tubing
- Gas lift valve
- Downhole safety valve
- HXMT

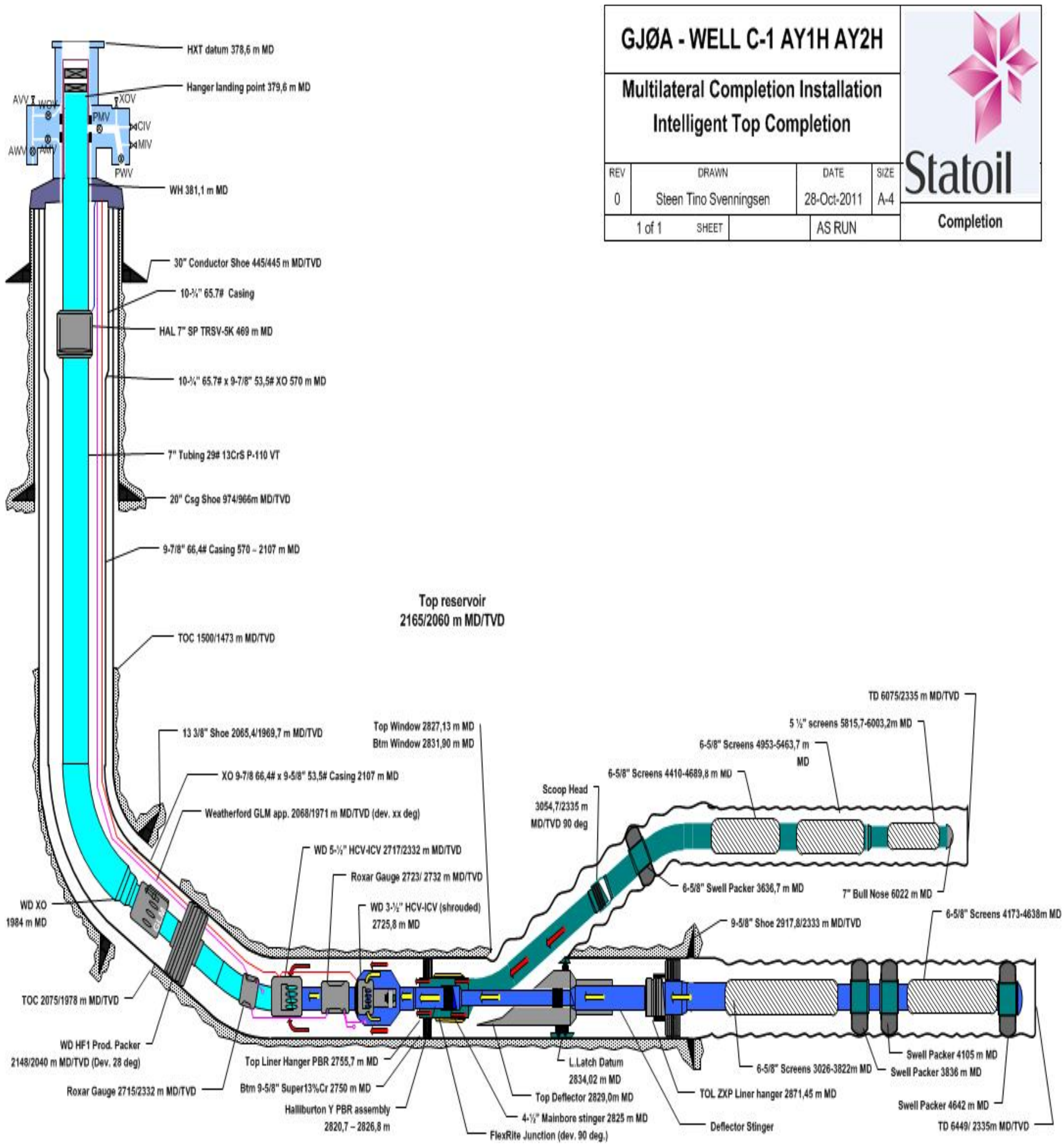


Figure 28 Multilateral completion oil well, intelligent top completion [41]

4.6 Well integrity

Figure 29 shows the current well integrity status of the eleven wells. There are nine green wells with no integrity issues. However, two of the wells are yellow. E-1 is yellow because of a production wing valve actuator failure in the XMT. The wing valve is, however, not a part of the barrier envelope and will not be of any concern during the P&A phase. Some concerns should be noted with regard to the cement height behind 13 3/8" casing in well C-4, this being lower than the NORSOK D-010 requirements after changes were implemented in 2013.

Figure 29 Current well integrity status [41]

4.7 Plug setting depth

To meet the requirements from NORSOK D-010, the well barrier must be set deeply enough so that the pressure from below does not fracture the formation at the depth of secondary plug. NORSOK D-010 states that the secondary plug shall be positioned such that the base of the plug is at a depth where the formation is strong enough to withstand the potential pressure from below [5]. A well that is permanently abandoned shall be plugged with eternal time perspective, and the reservoir pressure will not necessarily stay the same as it is now. For this thesis the following data is used:

Table 5 Reservoir data for the Gjøa field

Reservoir data		
Maximum Reservoir Pressure	236.7	Bar
Depth of Reservoir	2200	mTVD

Table 6 Fluid data for the Gjøa field

Fluid data		
Gas gradient (ρ_{gas})	0.225	SG
Oil gradient (ρ_{oil})	0.623	SG
Sea Water gradient (ρ_{sw})	1.03	SG

The minimum depth of the base of the secondary plug is thus found from equation 5 already derived in section 2.4.2.2 and gives:

- Gas gradient: TVD_{plug} = 1743 mTVD
- Oil gradient: TVD_{plug} = 1485 mTVD
- Sea Water gradient: TVD_{plug} = 498 mTVD

The gas gradient is considered as worst case scenario and is included to compare with oil and water filled casing. Because top of reservoir depth will vary, minimum setting depth must be calculated for each single well for later study.

5 Plug and Abandonment Design and Operation

This chapter will present an operational plan for the three different well types already categorized in section 4.5. The P&A is done according to NORSOK requirements. A WBS is made in Microsoft Visio, showing the well barrier envelope and associated WBE performing each operational step. Microsoft Visio is a tool much used in the industry for drawing graphics showing continuous and independent primary and secondary envelopes. The purpose of having two independent barrier envelopes is that one can allow incidents to happen, and yet have a safe back-up solution [42].

Something that is special about the Gjøa field, and which has already been mentioned, is the SWF that may occur in the weak Kyrre formation. This zone holds higher than normal pressure levels and caused trouble during drilling operations. When P&A operations are planned for on the Gjøa field, this zone shall be plugged with two barriers in addition to the reservoir barriers. This case study will include the operation of placing two barriers to seal off the zone for permanent P&A.

It is important to mention that there are always uncertainties related to well operations. When a well is entered to perform an operation, incidents may occur that require sudden changes in the primary plan. Most well operations are carefully planned in detail, but as unexpected events occur during the operation the plan must be adjusted. The operational steps presented in this case are based on operations performed according to the plan with no unexpected events. Also the depths will vary among the different wells, so adjustments should be made for further study. That is why this parameter has not been included through this examination.

5.1 Monobore Oil Well

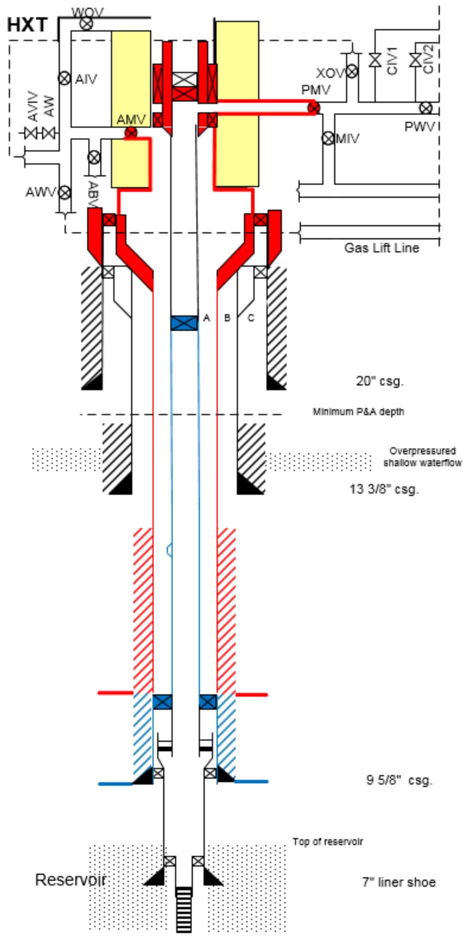
There are three monobore oil wells on the Gjøa field (B-1, B-3 and C-2). The well design of the oil wells is in many ways similar. B-1, however, has an additional 7" liner penetrating the reservoir. Therefore, B-1 is used as an example in this study due to the other two wells having many similarities with monobore gas wells.

5.1.1 Well status at start-up

Objective

- Permanently P&A well.
- Reservoir formation at ≈2200 mTVD.
- Assuming shallow water present.
- USIT/CBL/VDL log verified good cement behind 9 5/8" and 13 3/8" casing.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation above reservoir	51	
Production packer	7	
Completion string below DHSV	25/29	
9 5/8" casing below production packer	2	
Casing cement	22	
Downhole safety valve (DHSV)	8	
SECONDARY		
Formation at production packer depth	51	
9 5/8" casing	2	
9 5/8" casing hanger with seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower Tubing Hanger Crown Plug	11	
Upper Tubing Hanger Crown Plug	11	
Notes: - Completion string is tubing above prod. Packer including components -Gas Lift Valve is V_0 rated		

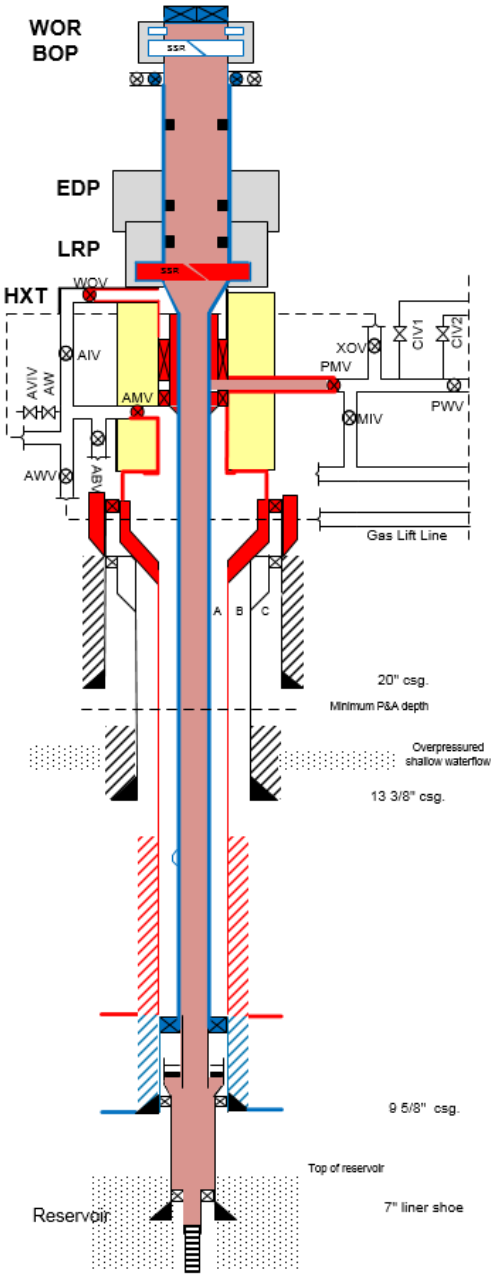
Figure 30 Well status at start-up

5.1.2 Bullheading operation

Objective and activity

- Install WOR before entering live well, expected high pressures.
- Pull crown plugs
- Kill the well by bullheading the reservoir fluids back into the formation and pump down heavy fluid to overbalance the well.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Horizontal XMS tree	31	
Workover riser	26	
LRP/EDP	42	
Subsea lubricator valve for testing	45	
Surface flow tree	34	
Wireline BOP	37	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes: - Subsea shear seal ram (SSR) is open during operation, but is marked as closed to illustrate barrier envelope towards reservoir -LRP is common WBE during this operation.		

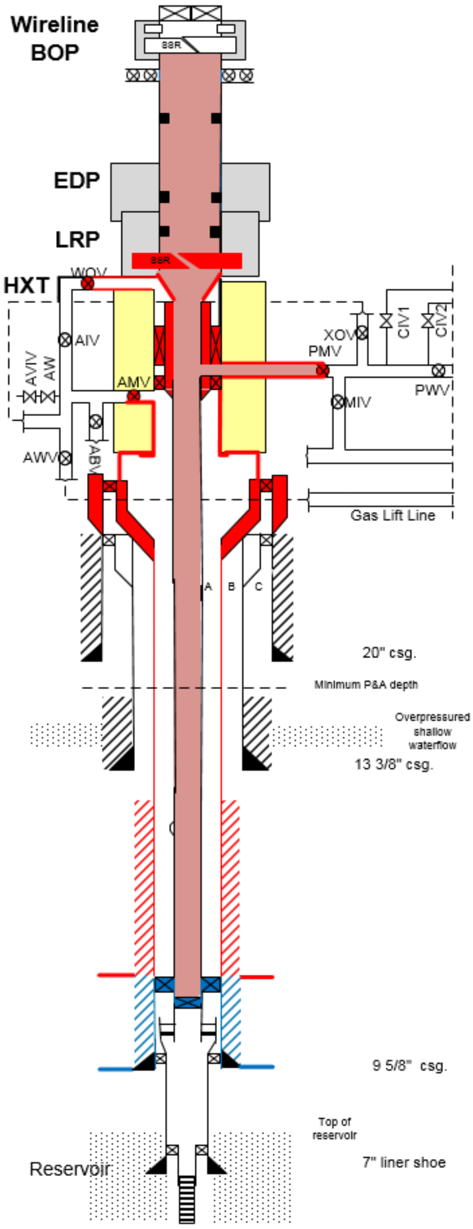
Figure 31 bullheading

5.1.3 Installing deep mechanical plug

Objective and activity

- After the well is killed a mechanical plug is set above the reservoir as foundation for further P&A work.
- Deep-set plug will function as a WBE.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

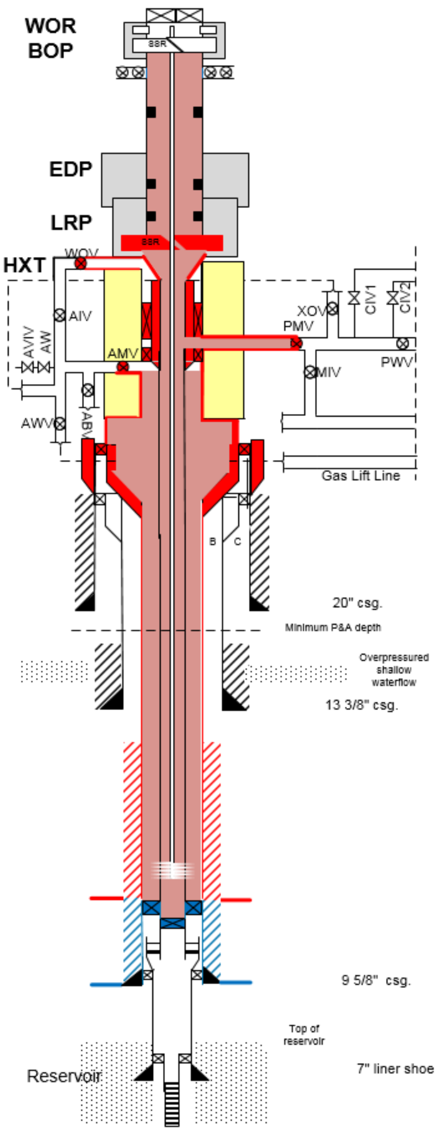
Figure 32 installing deep mechanical plug

5.1.4 Punch tubing and displace a-annulus above packer to weighted mud

Objective and activity

- To create good communication between tubing and annulus.
- When the foundation is set, the tubing will be punched. It will be perforated above the production packer.
- Brine is pumped down annulus to test the circulation and communication of the well.
- Run crown plugs

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

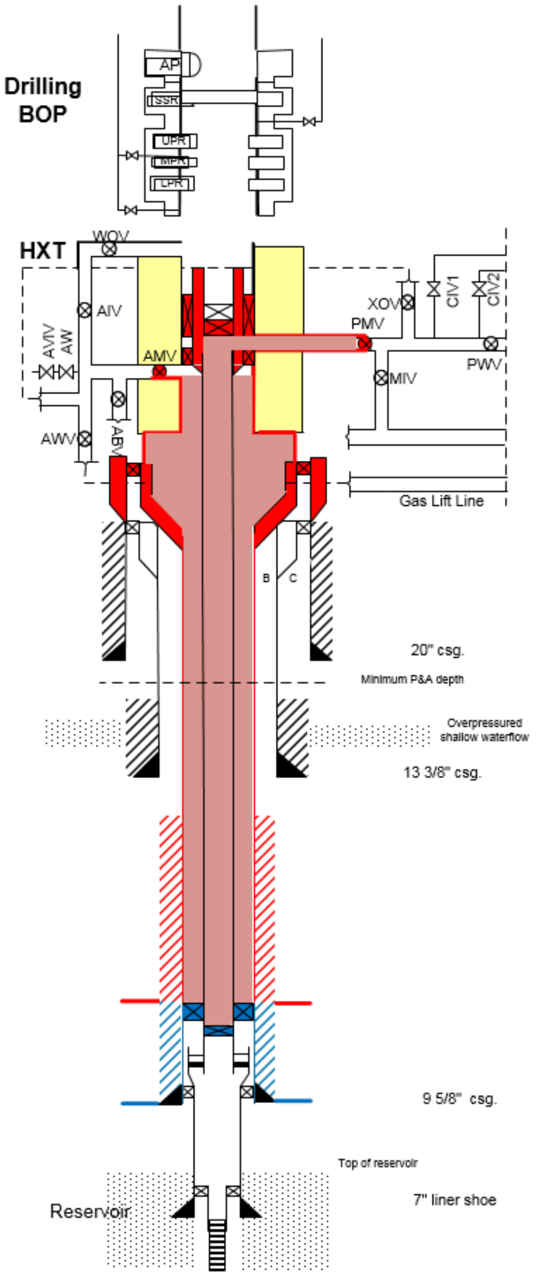
Figure 33 punching tubing

5.1.5 Pull WOR, run BOP

Objective and activity

- The WOR is replaced by a drilling BOP in order to pull the production tubing. As this operation cannot be performed through the smaller bore size WOR.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower tubing hanger crown plug	11	
Upper tubing hanger crown plug	11	
Notes:		

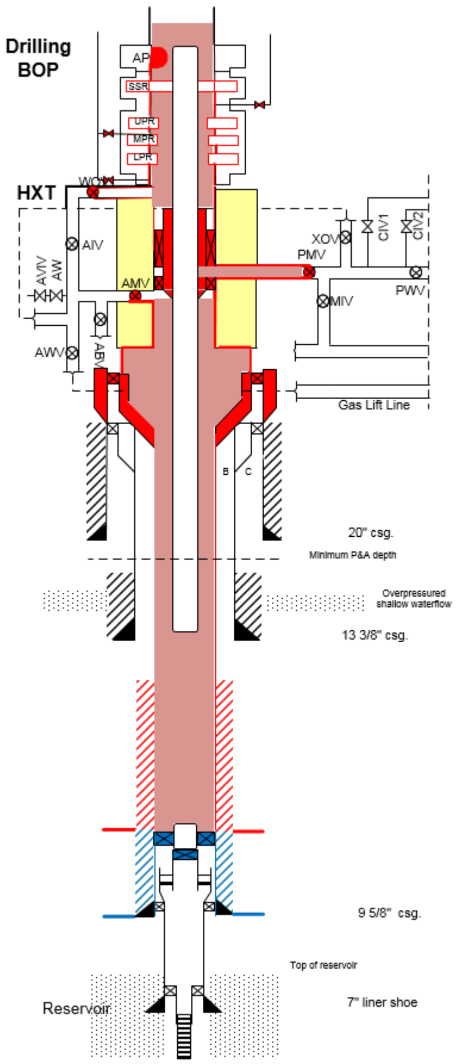
Figure 34 pull WOR, run BOP

5.1.6 Cut & pull tubing

Objective and activity

- Pull crown plugs.
- The production tubing is cut above the production packer with a cutting assembly with rotating knives, and then pulled.
- The tubing is cut to enable placement of cement plug for reservoir barriers.
- By use of BOP and marine riser, the P&A operations involving retrieval of tubing hanger and tubing, placement of barriers and cut and pull casings can be performed with sufficient barriers in place.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes: Displaced Kill weighted fluid (KWF) will also function as a barrier if possibility to monitore.		

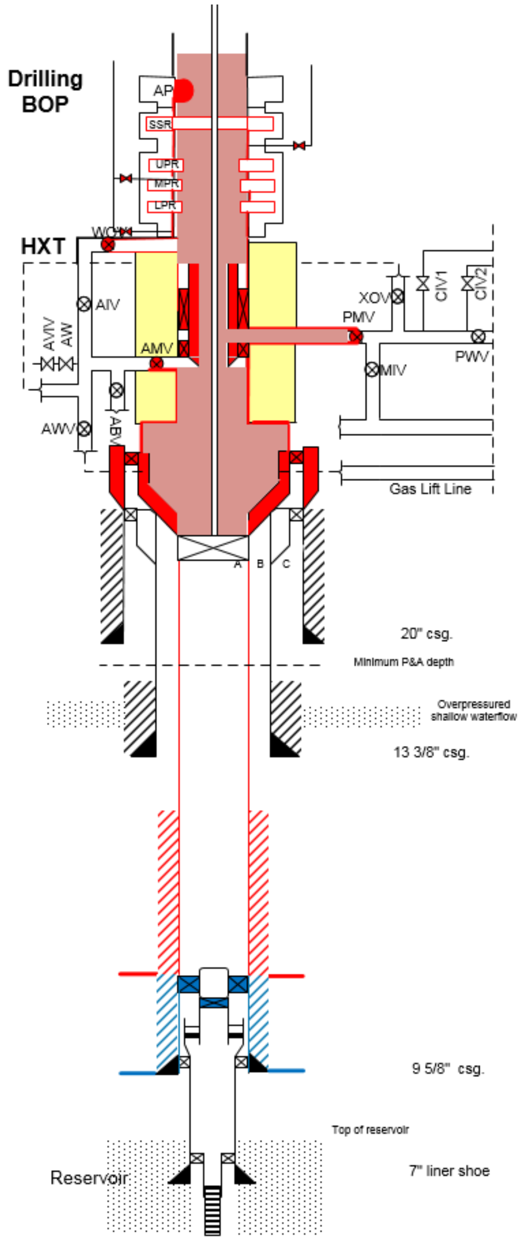
Figure 35 Cut and pull tubing

5.1.7 Install shallow plug

Objective and activity

- When the tubing is removed, a shallow plug shall be installed in production casing prior to removal of the XMT [5].

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes:		

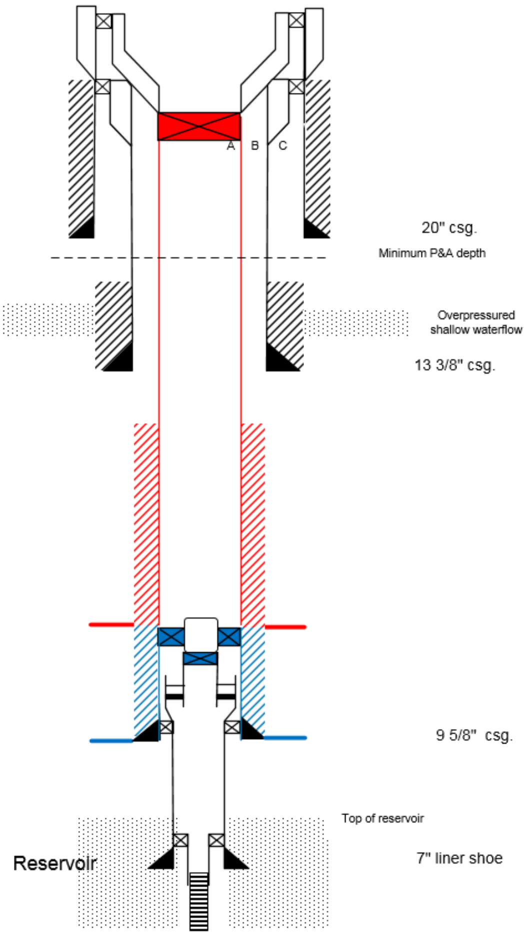
Figure 36 install shallow plug

5.1.8 Pull BOP & HXMT

Objective and activity

- The well is secured by to primary barriers, thus the BOP and HXMT can be pulled.
- The HXMT need to be pulled after tubing is retrieved and barriers are in place.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Mechanical plug – V0 rated	28	
Notes:		

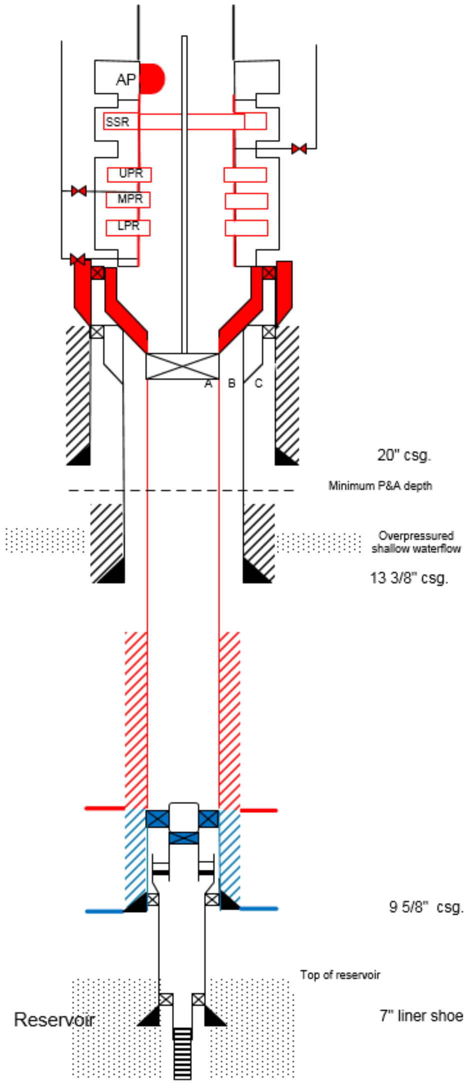
Figure 37 Pull driling BOP and HXMT

5.1.9 Run drilling BOP & retrieve shallow plug

Objective and activity

- Land BOP on slot.
- Retrieve shallow set plug.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug V0-rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Drilling BOP	4	
Notes:		

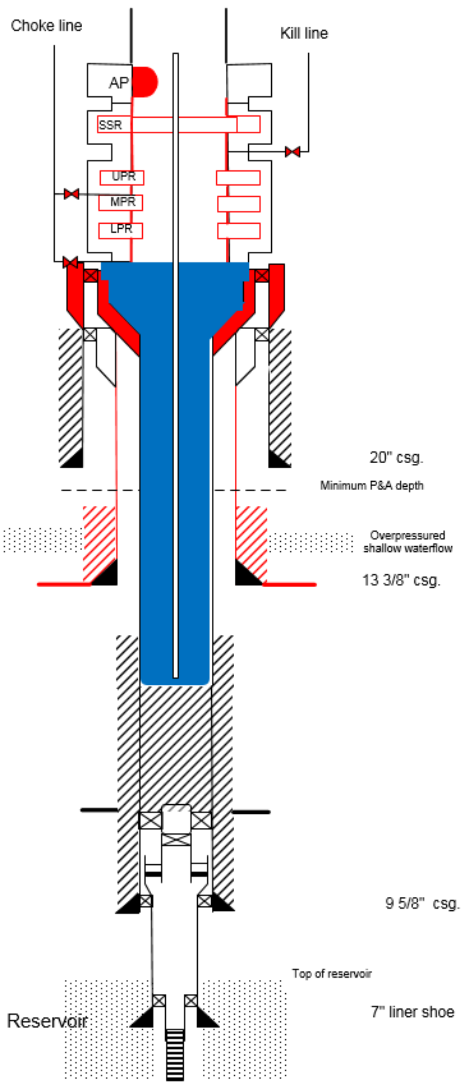
Figure 38 Run drilling BOP and retrieve shallow plug

5.1.10 Place cement plugs towards reservoir

Objective and activity

- Place first cement plug towards the reservoir.
- Place second cement plug towards the reservoir.
- Verify cement by tagging

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

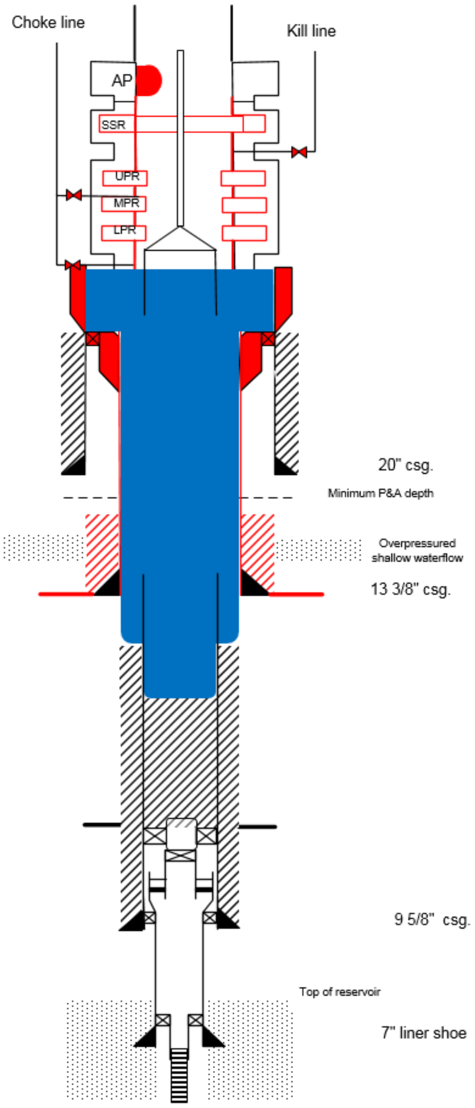
Figure 39 placing reservoir barriers

5.1.11 Cut and Pull 9 5/8" casing

Objective and activity

- Cut 9 5/8" casing at planned depth.
- Retrieve 9 5/8" seal assembly, casing and casing hanger.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

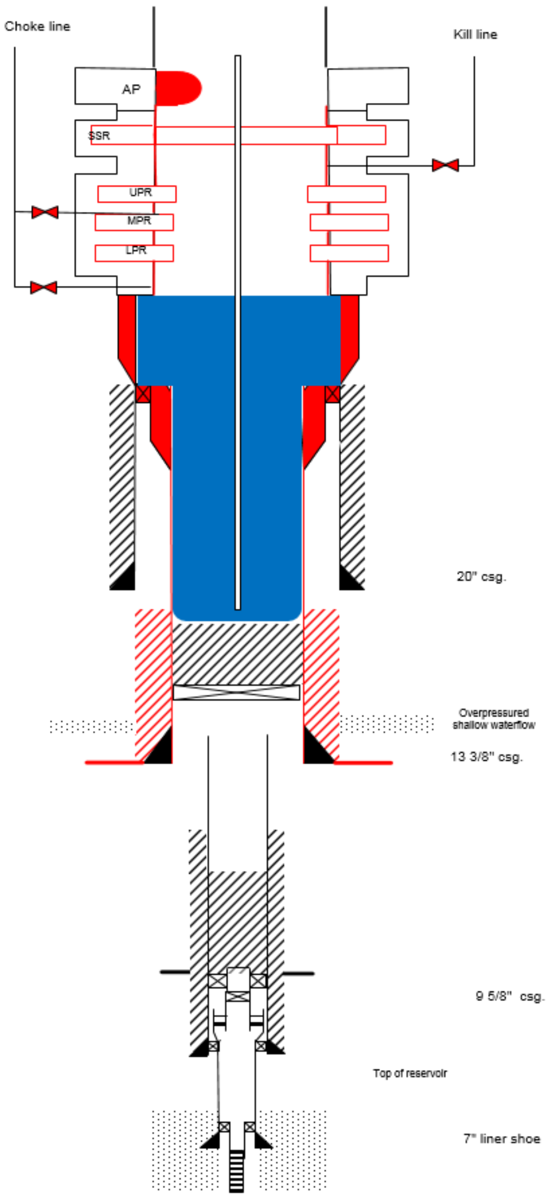
Figure 40 Cut and pull 9 5/8" casing

5.1.12 Setting primary and secondary barriers for overburden

Objective and activity

- Install 13 3/8 mechanical plug, tag and pressure test same.
- Displace to seawater.
- Set cement plugs on top of mechanical plug through setting tool.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

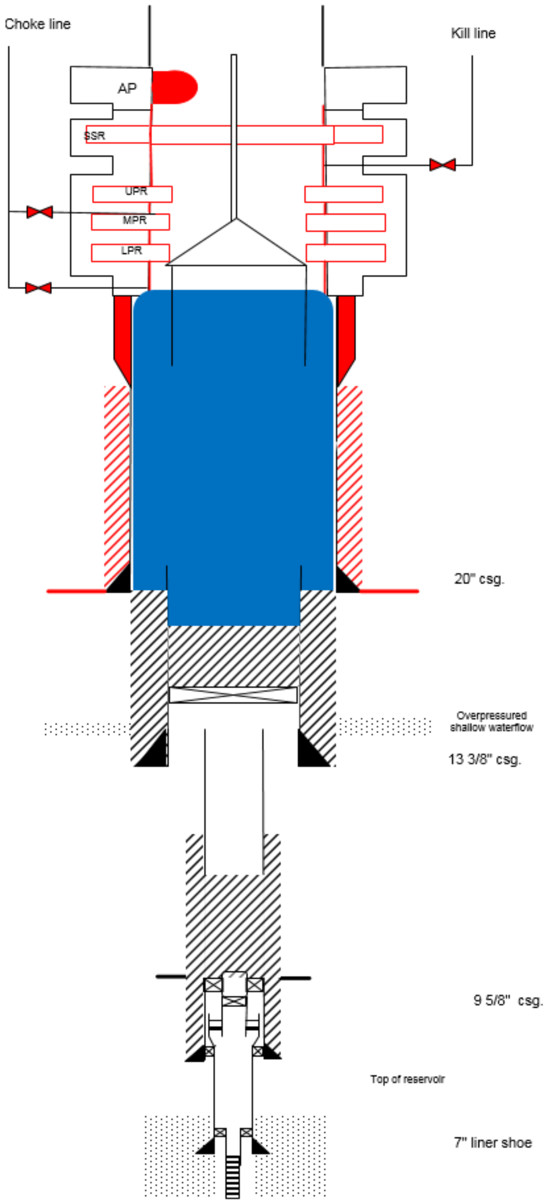
Figure 41 setting barriers towards overburden zone

5.1.13 Cut and pull 13 3/8" casing and pull seal assembly

Objective and activity

- Cut 13 3/8" casing at planned depth.
- Retrieve 13 3/8" seal assembly, casing and casing hanger.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

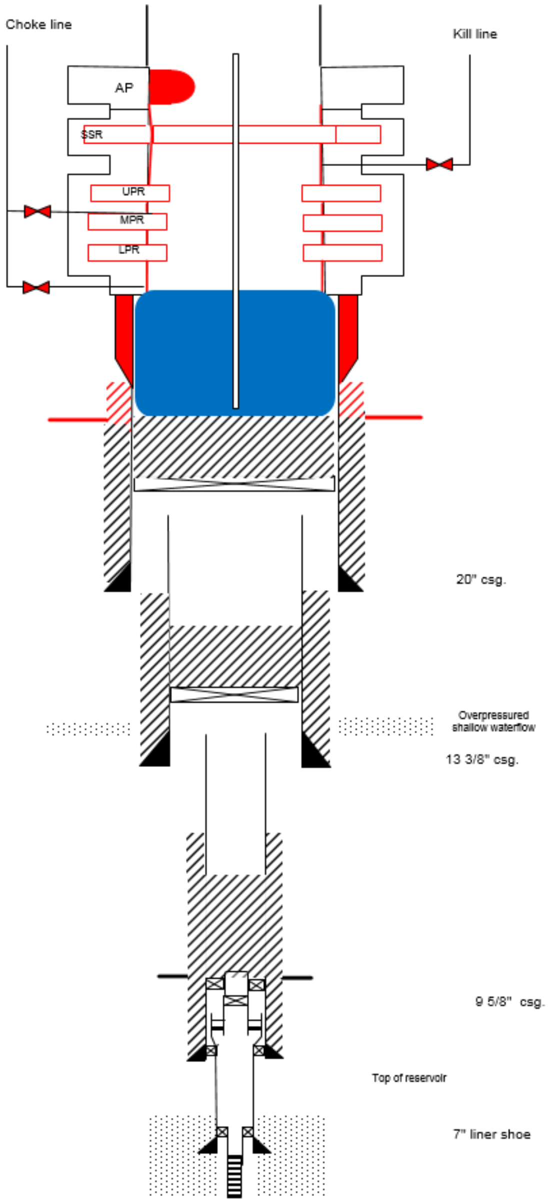
Figure 42 Cut and pull 13 3/8" casing

5.1.14 Open hole to surface barrier

Objective and activity

- Install 20" mechanical plug and pressure test same.
- Displace well to seawater.
- Place cement plug on top of mechanical plug through setting tool.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

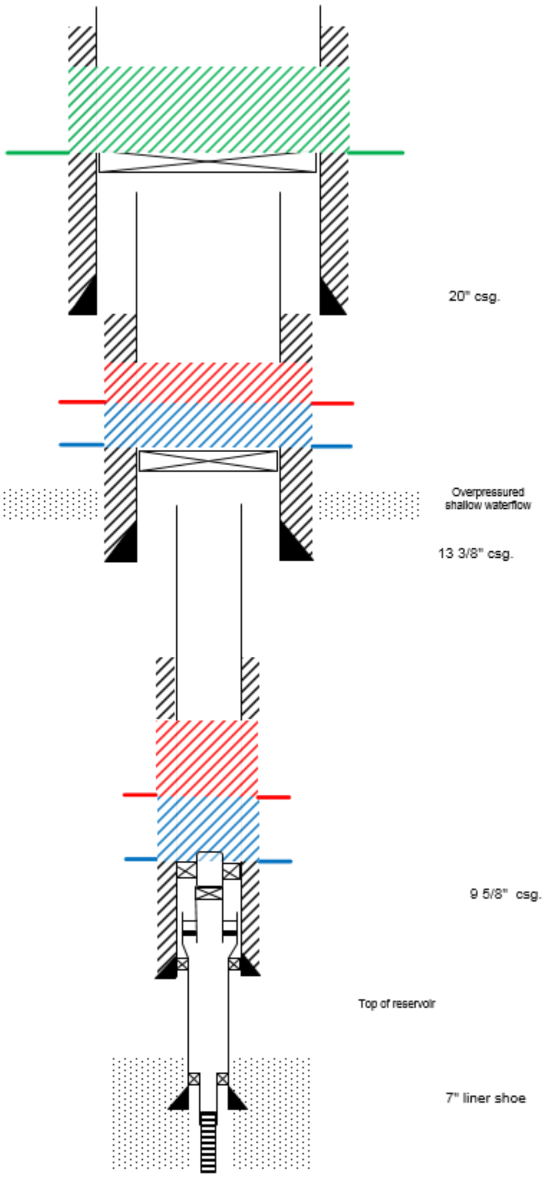
Figure 43 Placing open hole to surface barrier

5.1.15 Well status after permanent abandonment

Objective and activity

- Pull marine riser joints and BOP.
- Cut and retrieve WH below seabed.
- Well is final P&A'd.

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at prod. Packer depth (Shetland)	51	
9 5/8" Casing cement	22	
9 5/8 " Casing	2	
Cement plug #1	24	
SECONDARY		
Shetland formation	51	
9 5/8" casing	2	
9 5/8" casing cement	22	.
Cement plug #2	24	
PRIMARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8" casing	2	
Cement plug #3	24	
SECONDARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8 casing	2	
Cement plug #4	24	
Open hole to surface well barrier		
Casing cement	N/A	
20" casing cement	22	
20"casing	2	
Cement plug #5	24	
Notes: 1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" liner have confirmed good barrier cement		

Figure 44 Well permanently plugged and abandoned

5.2 Multilateral Oil Well

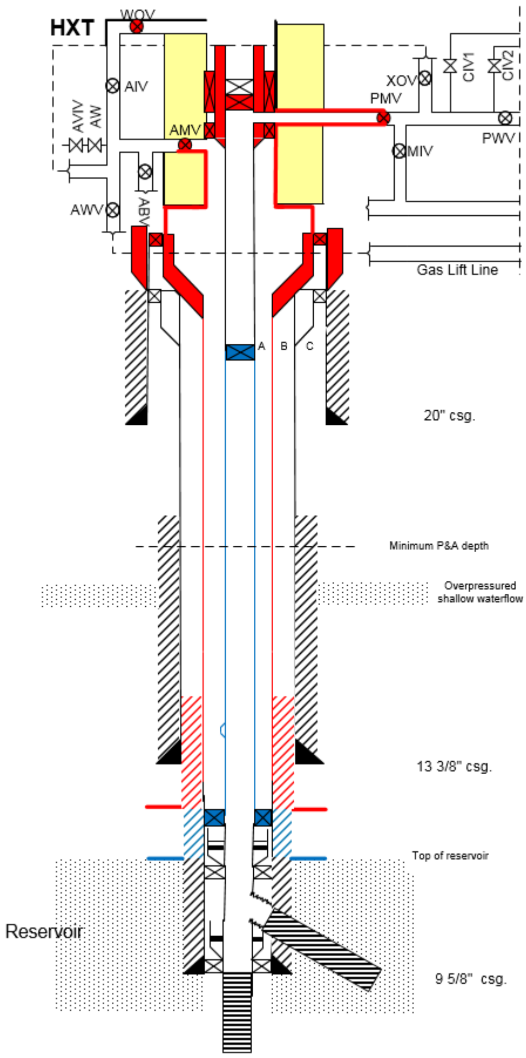
There are four multilateral oil wells on the Gjøa field (C-1, C-3, C-4 and D-1), with two horizontal branches into the same reservoir. All multilaterals are completed with DIACS to allow for individual clean up, and individual control of branches if needed.

5.2.1 Well status at start-up

Objective and activity

- Ref. to section 5.1.1

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation above reservoir	51	
Production packer	7	
Completion string below DHSV	25/29	
9 5/8" x9 7/8" x 10 ¾" casing	2	
9 5/8" liner cement	22	
DHSV	8	
SECONDARY		
Formation at prod.packer depth	51	
10 ¾" x 9 7/8" x 9 5/8" casing	2	
10 3/4" casing hanger with seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower Tubing Hanger Crown Plug	11	
Upper Tubing Hanger Crown Plug	11	
Notes: -Completion string is tubing above production packer including components. -Liner hanger packer and Gas Lift Valve is V_0 rated		

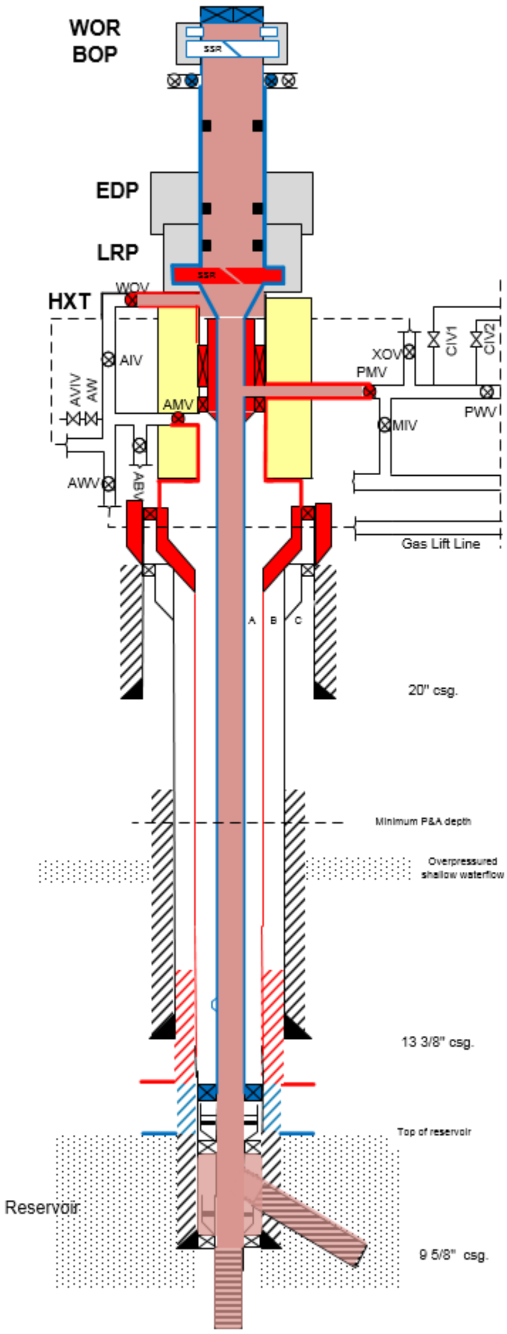
Figure 45 Well status at start-up

5.2.2 Bullheading operation

Objective and activity

- Ref. to section 5.1.2

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Horizontal XMS tree	31	
Workover riser	26	
LRP / EDP	42	
Subsea lubricator valve for testing	45	
Surface flow tree	34	
Wireline BOP	37	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes: - Subsea shear seal ram (SSR) is open during operation, but is marked as closed to illustrate barrier envelope towards reservoir - LRP is common WBE during this operation		

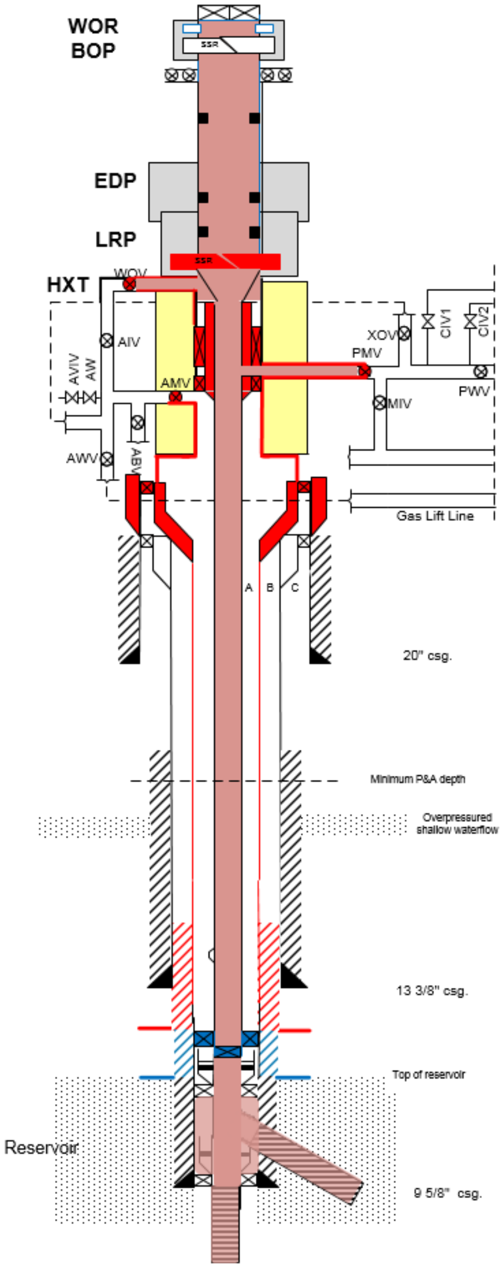
Figure 46 Bullheading operation

5.2.3 Install deep mechanical plug

Objective and activity

- Ref. to section 5.1.3

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

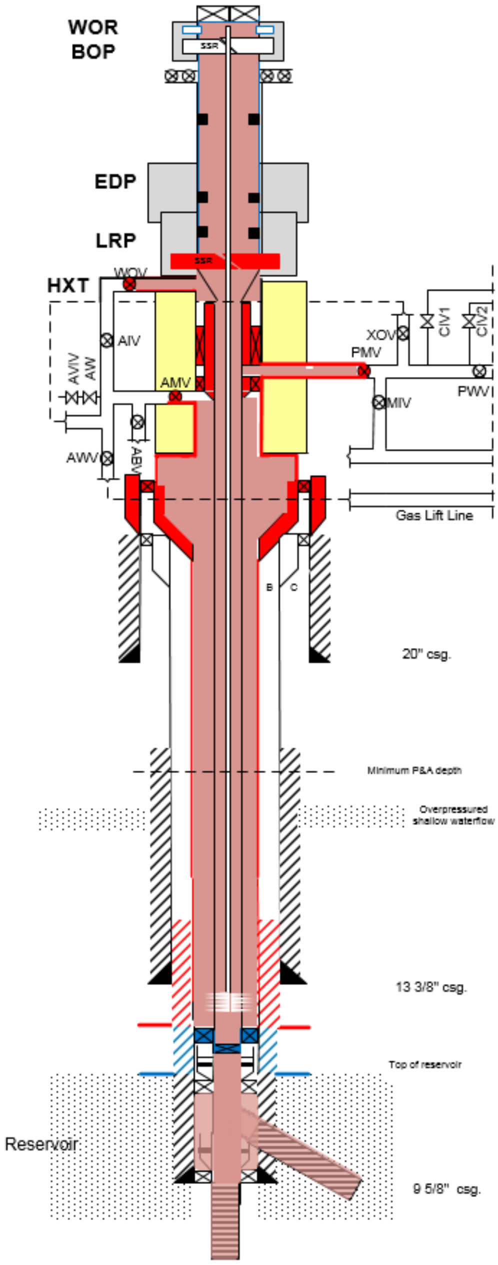
Figure 47 Installing deep mechanical plug

5.2.4 Punch tubing and displace upper annulus to KWM

Objective and activity

- Ref. to section 5.1.4

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

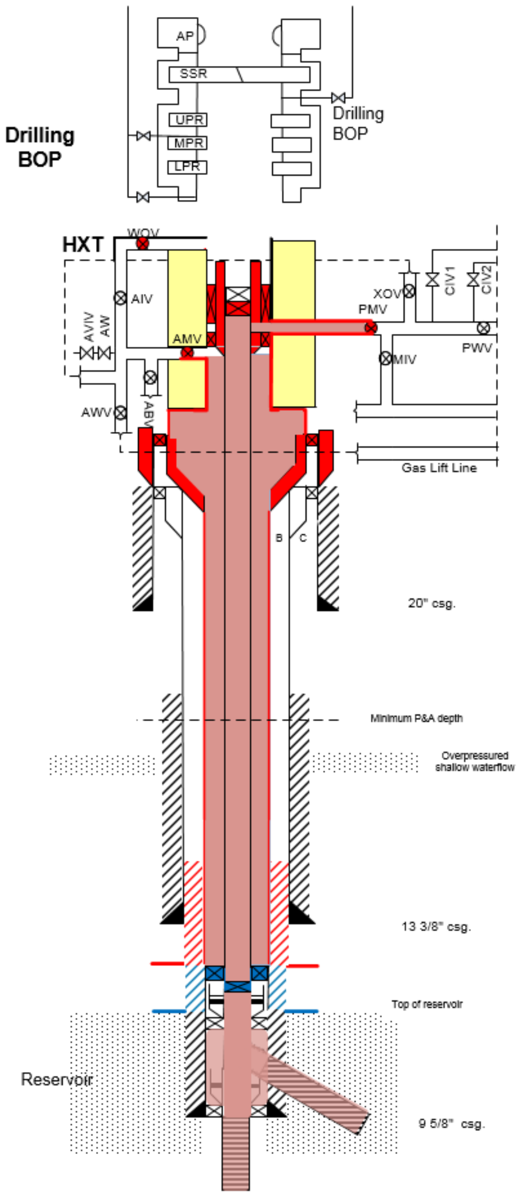
Figure 48 Punch tubing

5.2.5 Pull WOR and Run drilling BOP

Objective and activity

- Ref. to section 5.1.5

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

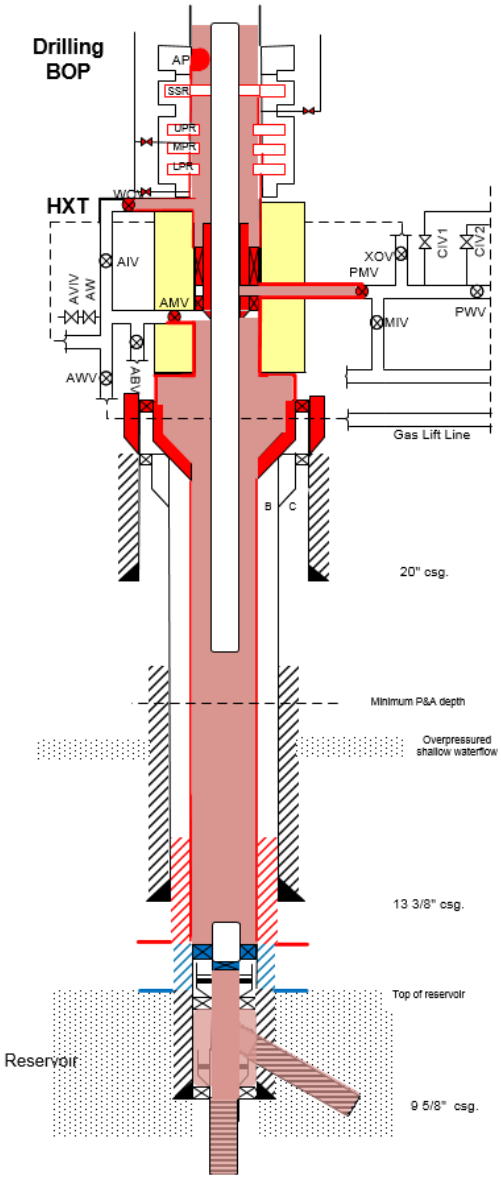
Figure 49 Pull WOR and run drilling BOP

5.2.6 Cut and pull tubing

Objective and activity

- Ref. to section 5.1.6

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes: Displaced Kill weighted fluid (KWF) will also function as a barrier if possibility to monitore.		

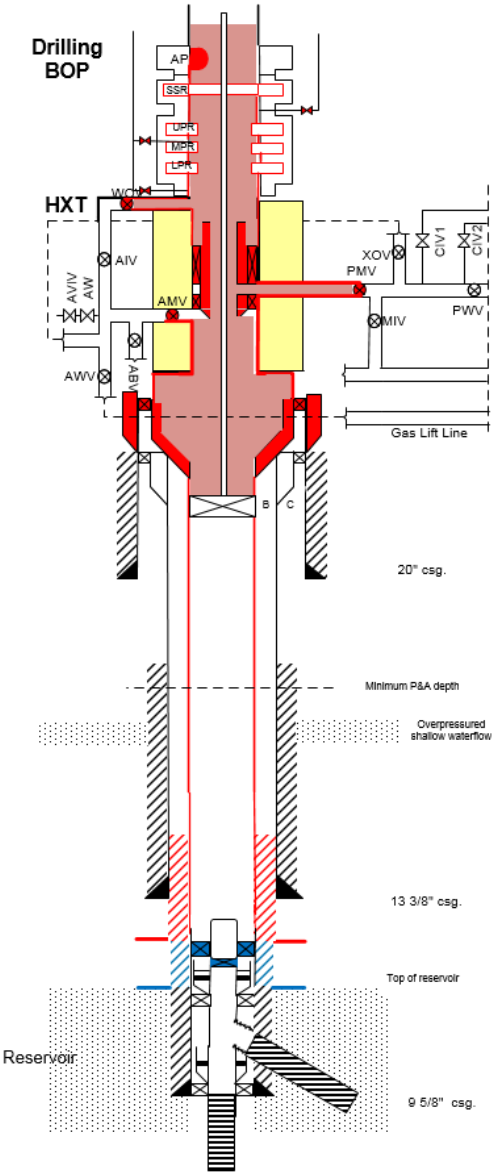
Figure 50 Cut and pull tubing

5.2.7 Install shallow plug

Objective and activity

- Ref. to section 5.1.7

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes: Displaced Kill weighted fluid (KWF) will also function as a barrier if possibility to monitore.		

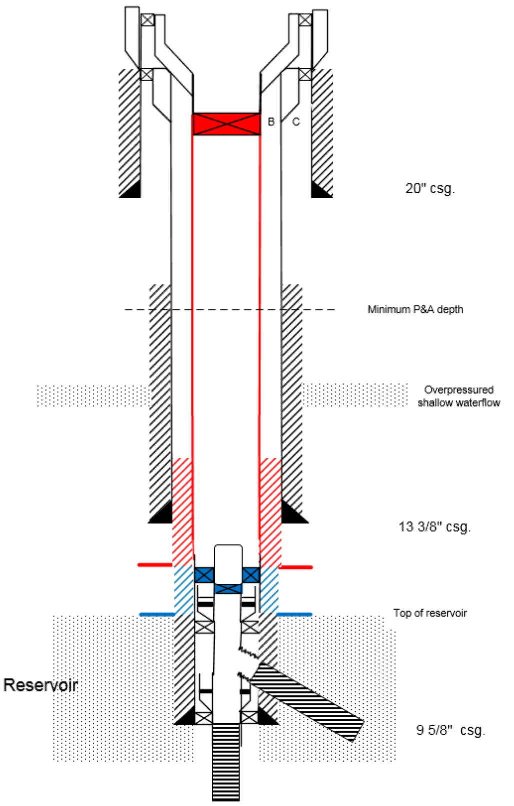
Figure 51 Install shallow plug

5.2.8 Pull BOP and HXMT

Objective and activity

- Ref. to section 5.1.8

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes: Displaced Kill weighted fluid (KWF) will also function as a barrier if possibility to monitore.		

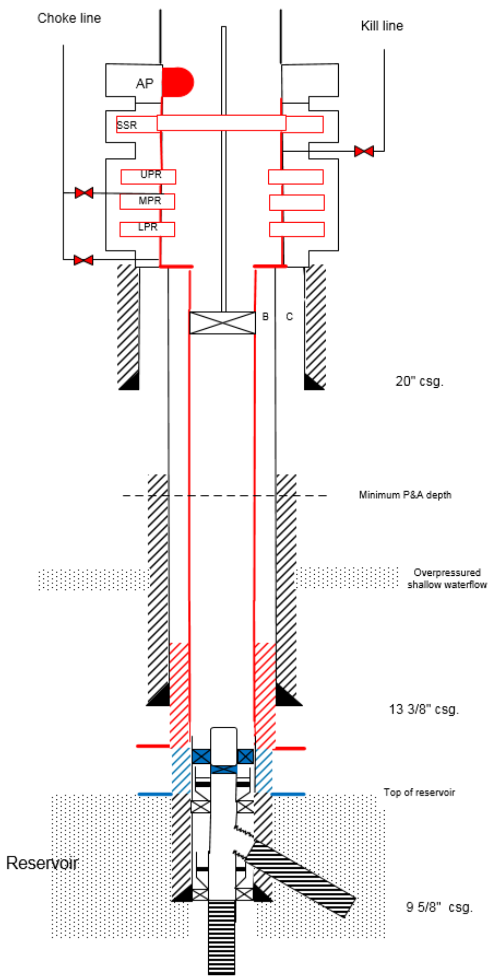
Figure 52 Pull Drilling BOP and HXMT

5.2.9 Run drilling BOP and retrieve shallow plug

Objective and activity

- Ref. to section 5.1.9

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Mechanical plug – V0 rated	28	
Notes:		

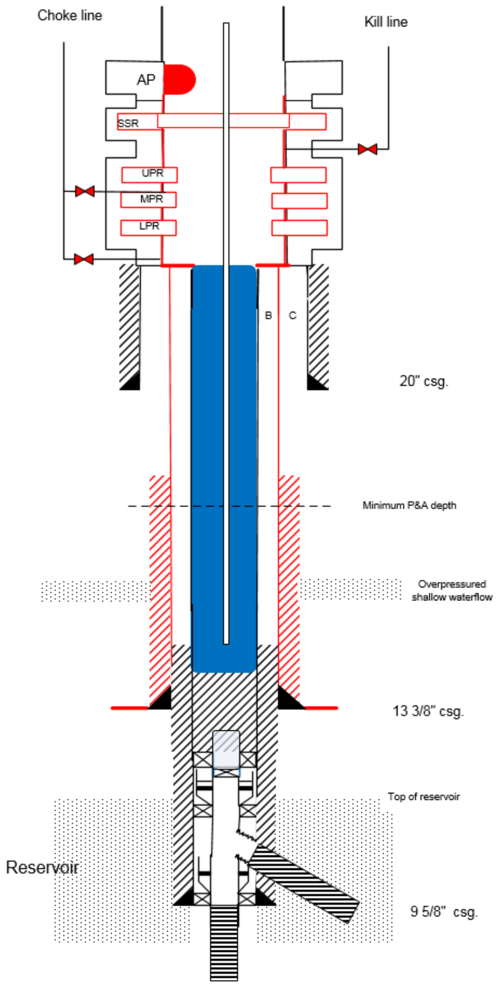
Figure 53 Run drilling BOP and retrieve shallow plug

5.2.10 Barriers towards the reservoir

Objective and activity

- Ref. to section 5.1.10

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

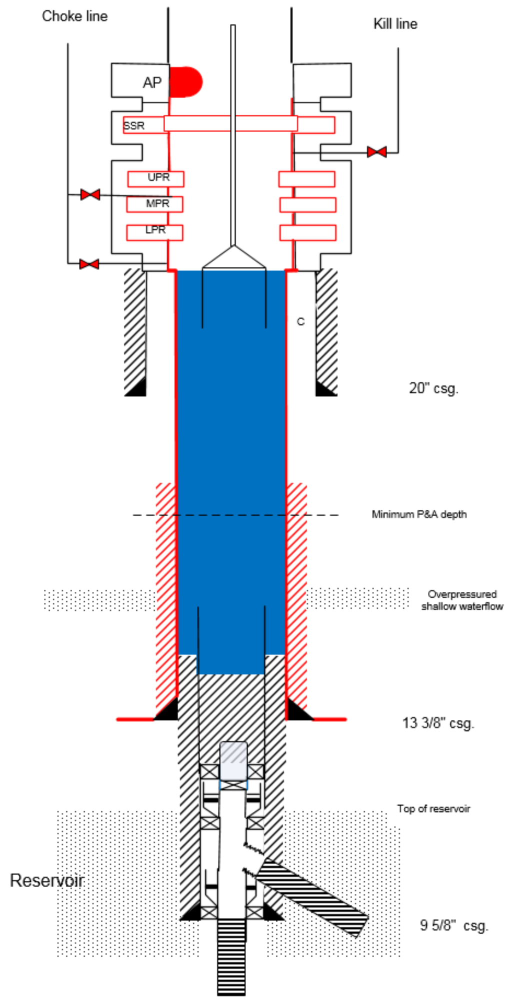
Figure 54 Setting barriers towards reservoir

5.2.11 Cut and pull 9 5/8" casing

Objective and activity

- Ref. to section 5.1.11

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

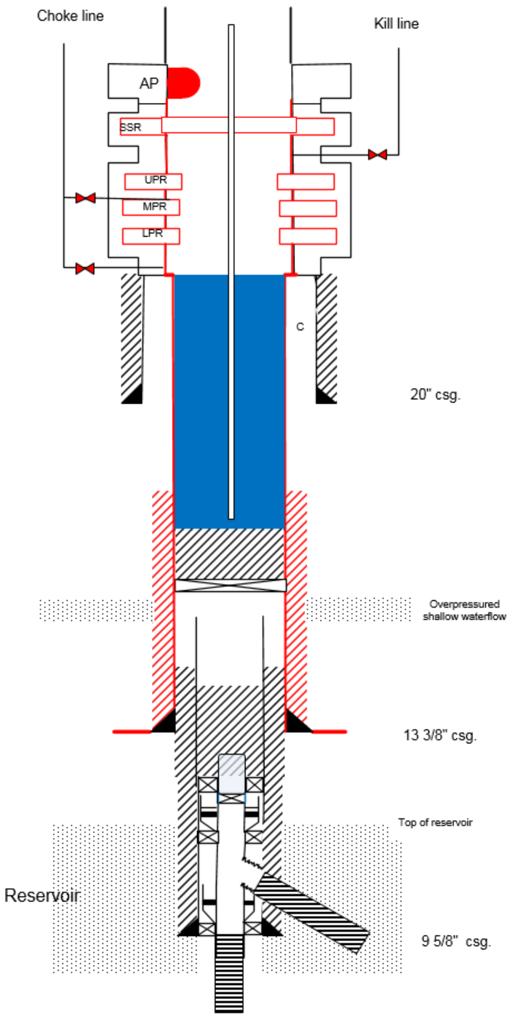
Figure 55 Cut and pull 9 5/8" casing

5.2.12 Setting primary and secondary barriers for overburden

Objective and activity

- Ref. to section 5.1.12

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

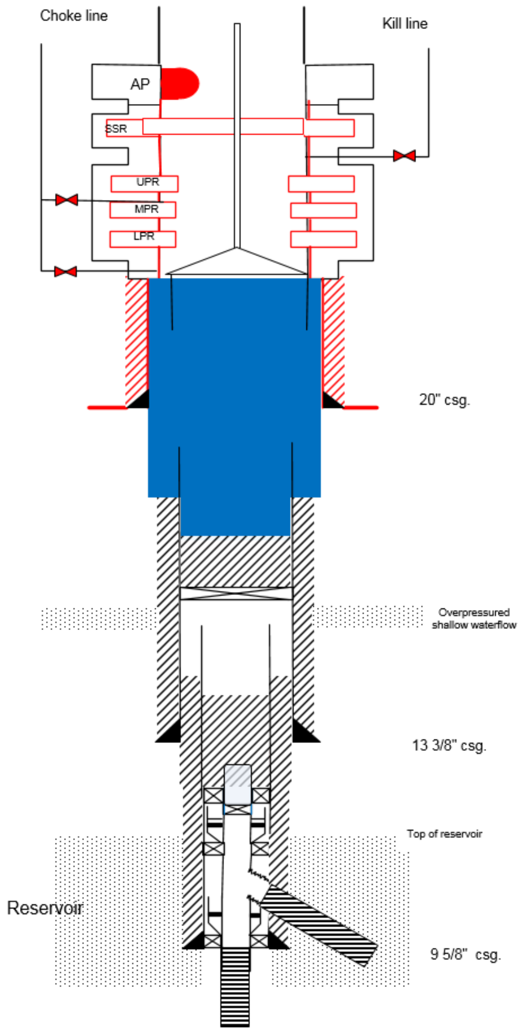
Figure 56 Setting barriers towards overburden

5.2.13 Cut and pull 13 3/8" casing

Objective and activity

- Ref. to section 5.1.13

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

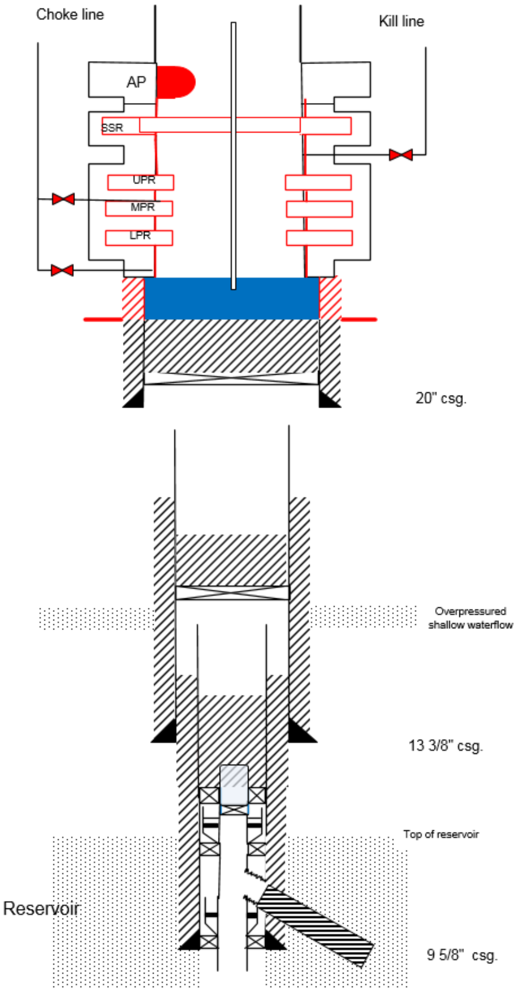
Figure 57 Cut and pull 13 3/8" casing

5.2.14 Open hole to surface barrier

Objective and activity

- Ref. to section 5.1.14

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

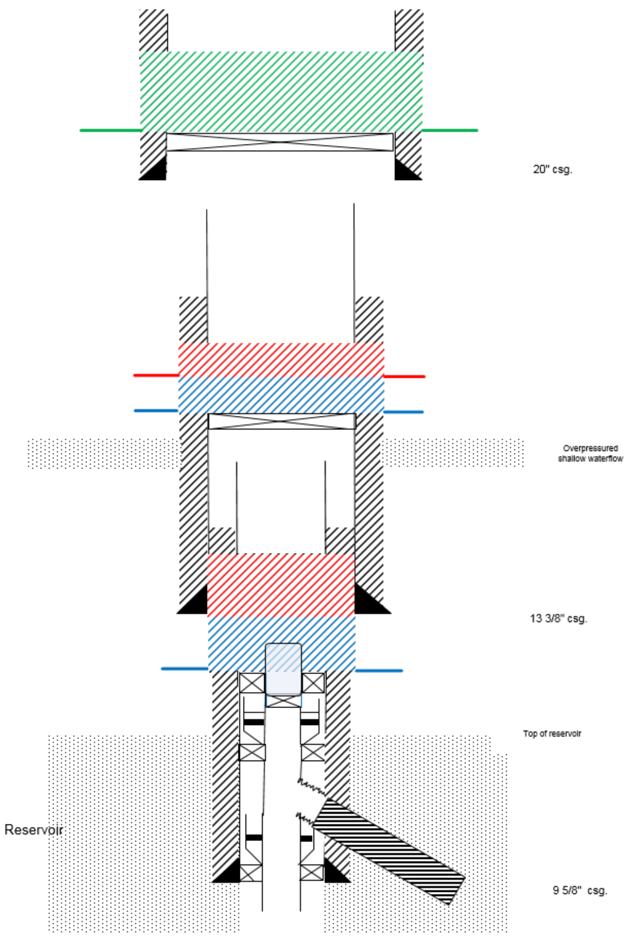
Figure 58 Setting open hole to surface barrier

5.2.15 Well status after permanent abandonment

Objective and activity

- Ref. to section 5.1.15

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at prod. Packer depth (Shetland)	51	
9 5/8" Casing cement	22	
9 5/8 " Casing	2	
Cement plug #1	24	
SECONDARY		
Shetland formation	51	
9 5/8" casing	2	
9 5/8" casing cement	22	.
Cement plug #2	24	
PRIMARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8" casing	2	
Cement plug #3	24	
SECONDARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8 casing	2	
Cement plug #4	24	
Open hole to surface well barrier		
Casing cement	N/A	
20" casing cement	22	
20"casing	2	
Cement plug #5	24	
Notes: 1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" liner have confirmed good barrier cement		

Figure 59 Permanently plugged and abandoned well

5.3 Monobore Gas Well

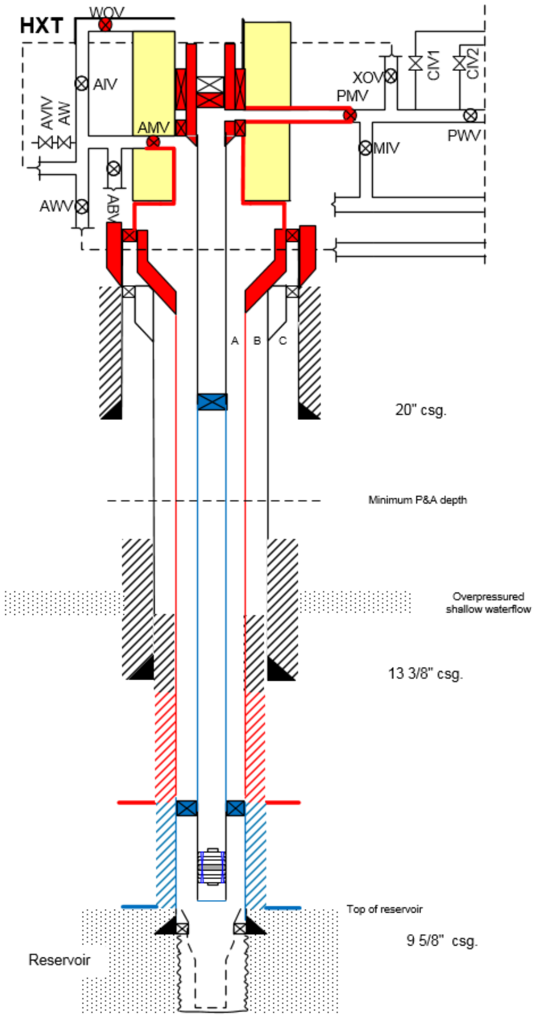
There are four monobore gas wells on the Gjøa field (B-2, D-3, E-1 and F-1), drilled from vertical up to maximum 46^0 deviation. All gas wells have a very similar well design, thus the P&A operation can be done in the same manner.

5.3.1 Well status at start-up

<u>Objective</u>

- Ref. to section 5.1.1

<u>Barriers</u>



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation above reservoir	51	
Cemented 9 5/8" casing below prod. Packer	2/22	
Production packer	7	
Completion string with components below DHSV	25/29	
DHSV	8	
SECONDARY		
Formation at prod. packer depth	51	
Cemented 9 5/8" x 10 ¾" casing above prod. Packer	2/22	.
9 5/8" casing hanger with seal assembly	5	
HXT	31	
Tubing Hanger	10	
Lower Tubing Hanger Crown Plug	11	
Upper Tubing Hanger Crown Plug	11	
Notes:		

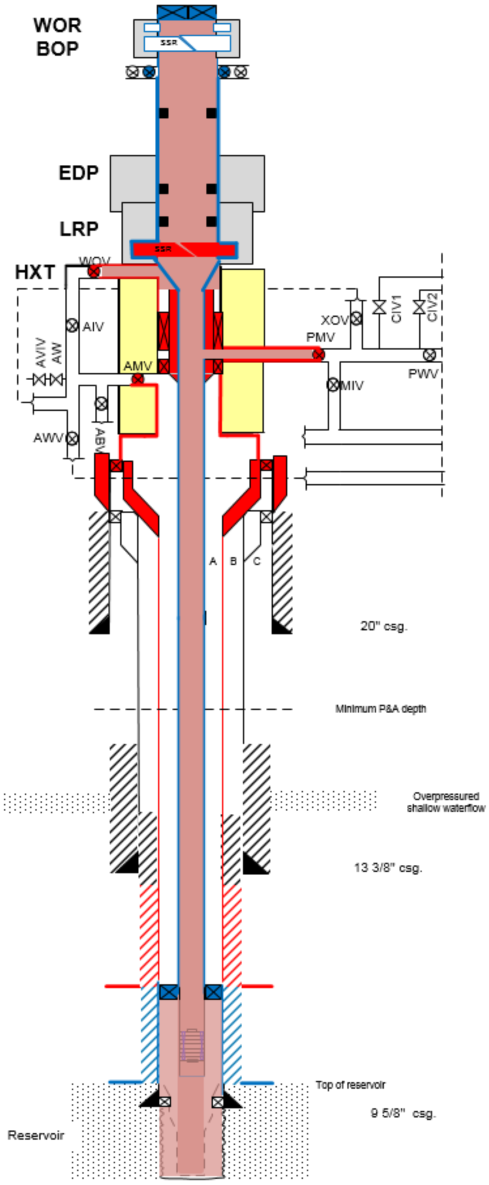
Figure 60 Well status at start-up

5.3.2 Bullheading operation

Objective and activity

- Ref. to section 5.1.2

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Horizontal XMS tree	31	
Workover riser	26	
LRP / EDP	42	
Subsea lubricator valve for testing	45	
Surface flow tree	34	
Wireline BOP	37	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes: - Subsea shear seal ram (SSR) is open during operation, but is marked as closed to illustrate barrier envelope towards reservoir - LRP is common WBE during this operation		

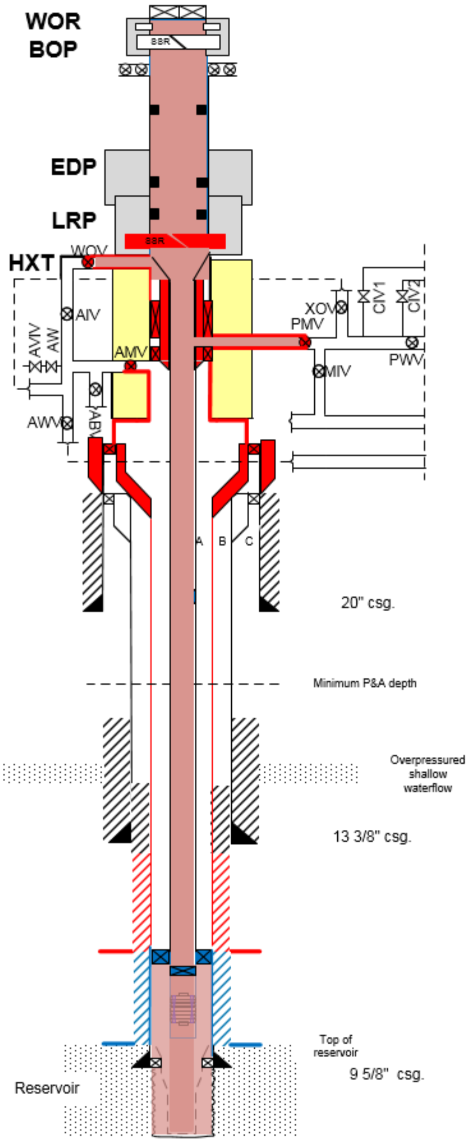
Figure 61 Bullheading operation

5.3.3 Install deep mechanical plug

Objective and activity

- Ref. to section 5.1.3

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

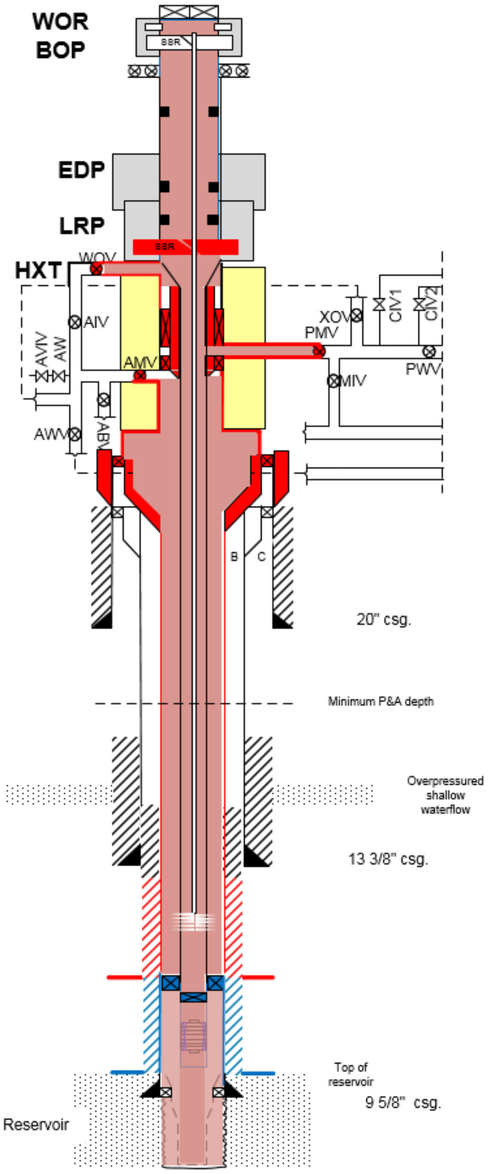
Figure 62 Installing deep mechanical plug

5.3.4 Punch tubing and displace upper annulus to KWM

Objective and activity

- Ref. to section 5.1.4

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – Vo rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower riser package (LRP)	42	
Notes:		

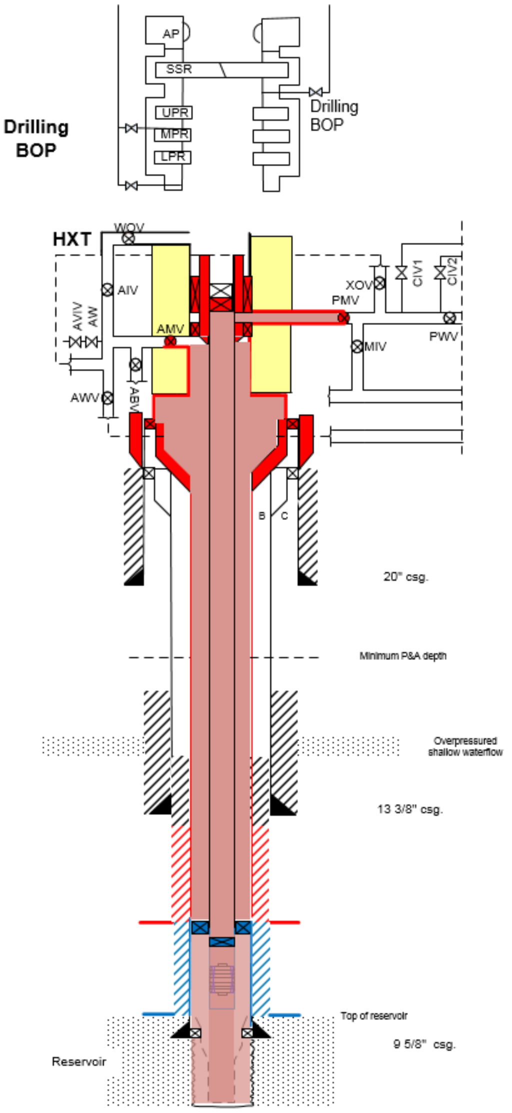
Figure 63 Punching tubing

5.3.5 Pull WOR and Run drilling BOP

Objective and activity

- Ref. to section 5.1.5

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug – V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Lower tubing hanger crown plug	11	
Upper tubing hanger crown plug	11	
Notes:		

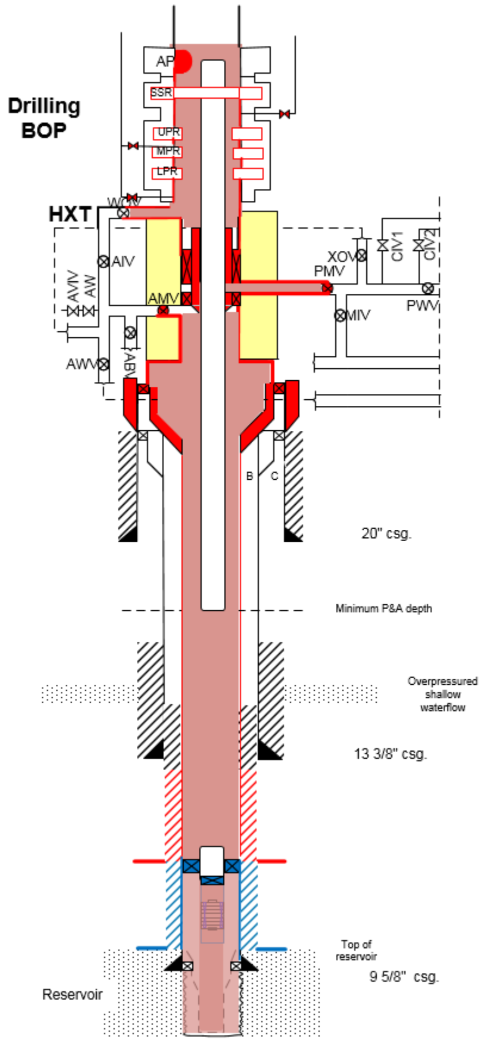
Figure 64 Pull WOR and run up drilling BOP

5.3.6 Cut and pull tubing

Objective and activity

- Ref. to section 5.1.6

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes: Displaced Kill weighted fluid (KWF) will also function as a barrier if possibility to monitore.		

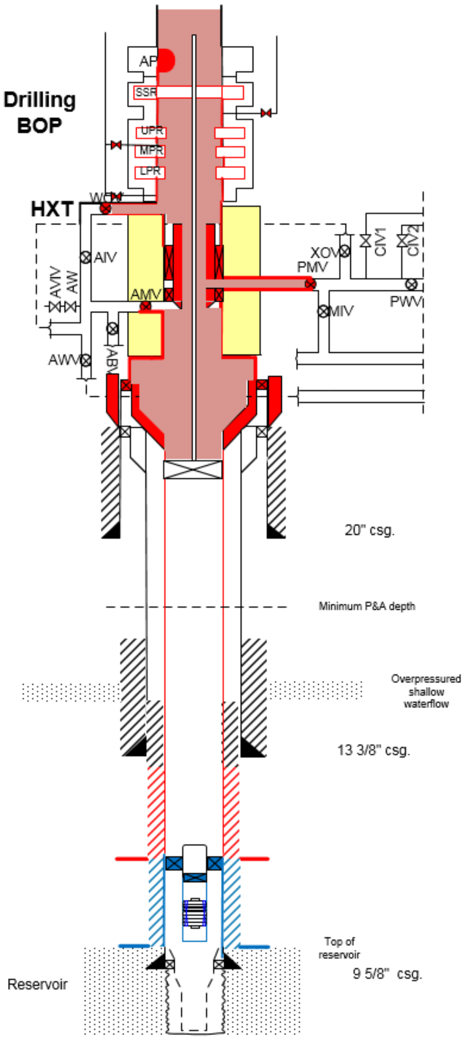
Figure 65 Cut and pull tubing

5.3.7 Install shallow plug

Objective and activity

- Ref. to section 5.1.7

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Tubing hanger with seals	10	
Horizontal XMS tree	31	
Drilling BOP	4	
Notes:		

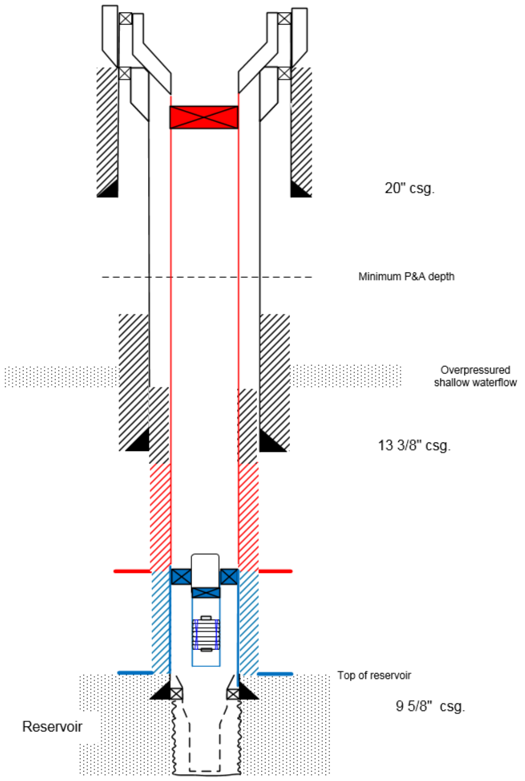
Figure 66 Installing shallow plug

5.3.8 Pull BOP and HXMT

Objective and activity

- Ref. to section 5.1.8

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	Ref. Table NORSOK D-010	Verification of barrier elements
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Mechanical plug – V0 rated	28	
Notes:		

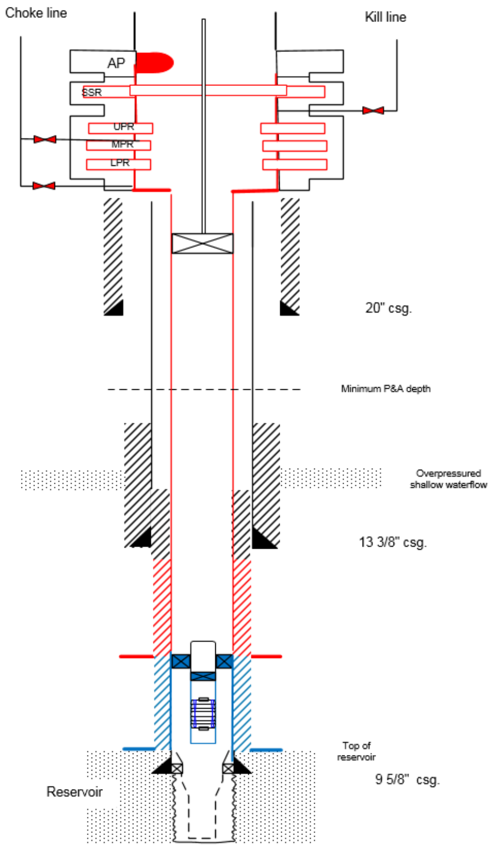
Figure 67 Pull BOP and HXMT

5.3.9 Run drilling BOP and retrieve shallow plug

Objective and activity

- Ref. to section 5.1.9

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at casing shoe	51	
9 5/8 casing cement up to production packer	22	
9 5/8 casing	2	
Production packer	7	
Production tubing	25	
Mechanical plug- V0 rated	28	
SECONDARY		
Formation at prod.packer depth	51	
9 5/8" casing	2	.
9 5/8" casing cement	22	
9 5/8" casing hanger and seal assembly	5	
Mechanical plug – V0 rated	28	
Notes:		

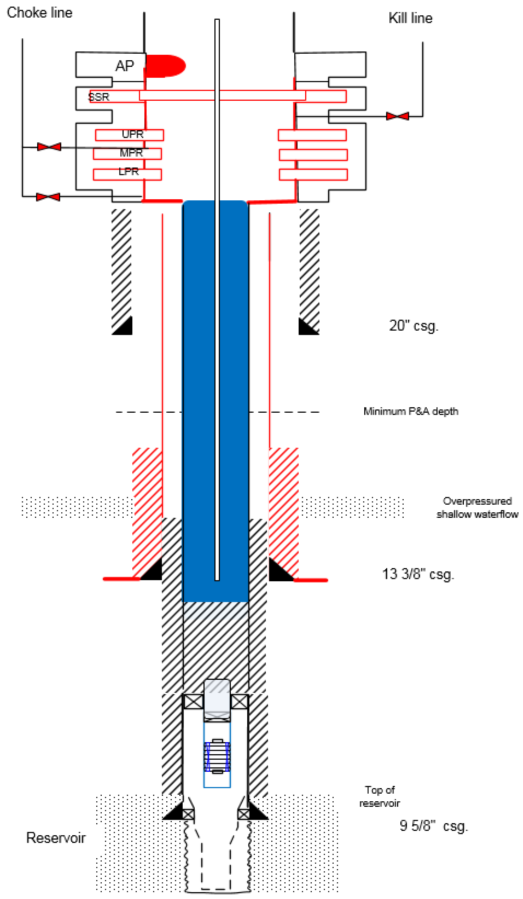
Figure 68 Run drilling BOP and retrieve shallow plug

5.3.10 Barriers towards reservoir

Objective and activity

- Ref. to section 5.1.10

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

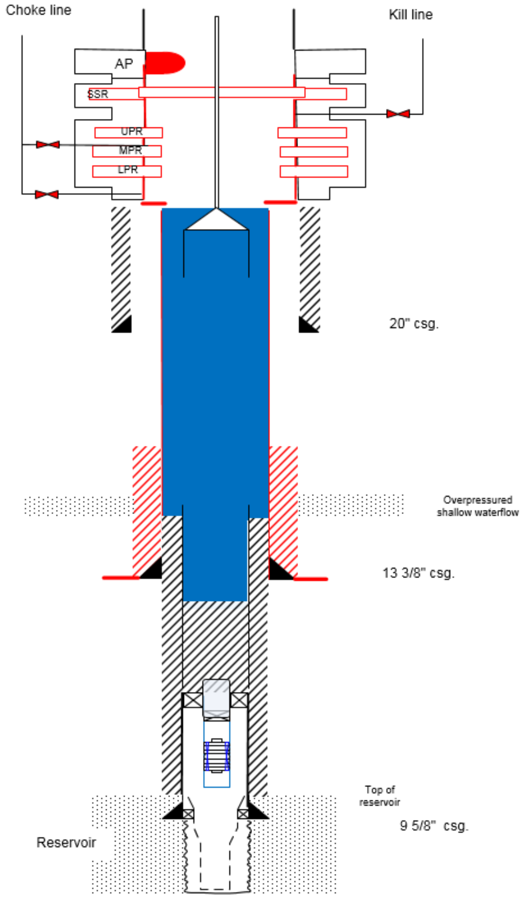
Figure 69 Setting barriers towards reservoir

5.3.11 Cut and pull 9 5/8” casing

Objective and activity

- Ref. to section 5.1.11

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

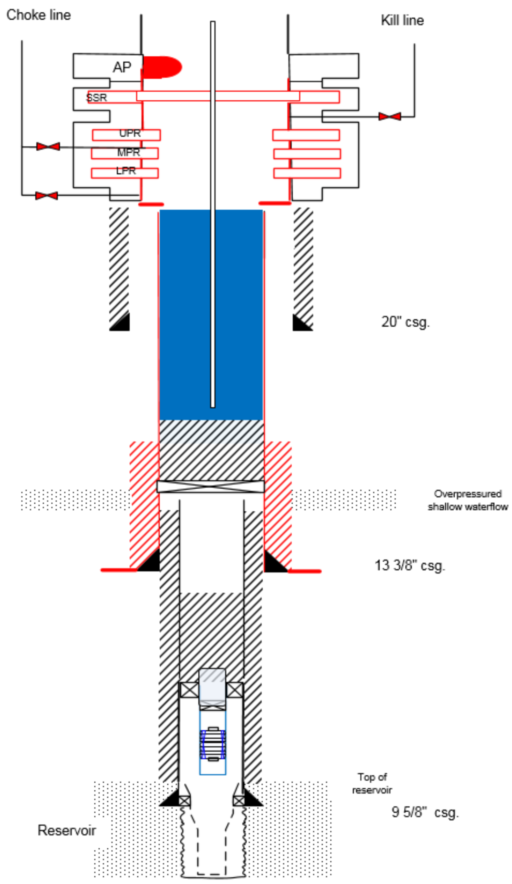
Figure 70 Cut and pull 9 5/8” casing

5.3.12 Setting primary and secondary barriers for overburden

Objective and activity

- Ref. to section 5.1.12

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 13 3/8" casing shoe	51	
13 3/8" casing	2	
13 3/8 casing cement	22	.
13 3/8 casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

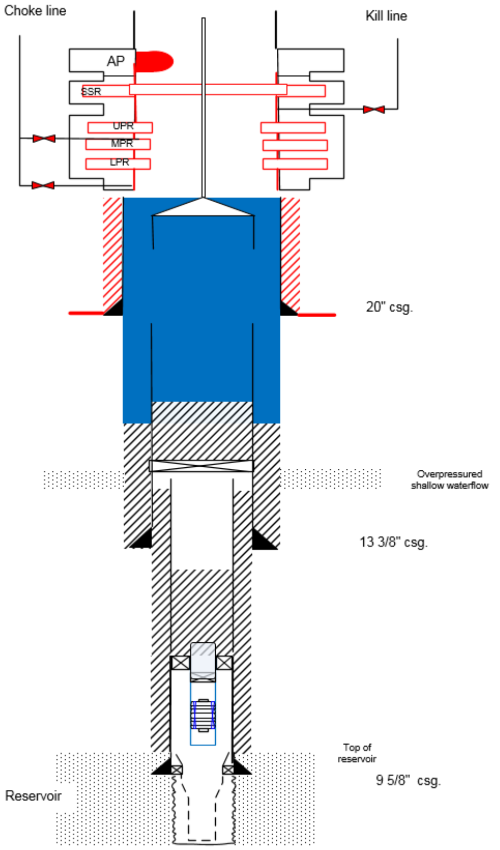
Figure 71 Setting barriers towards overburden

5.3.13 Cut and pull 13 3/8" casing

Objective and activity

- Ref. to section 5.1.13

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Multilateral oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

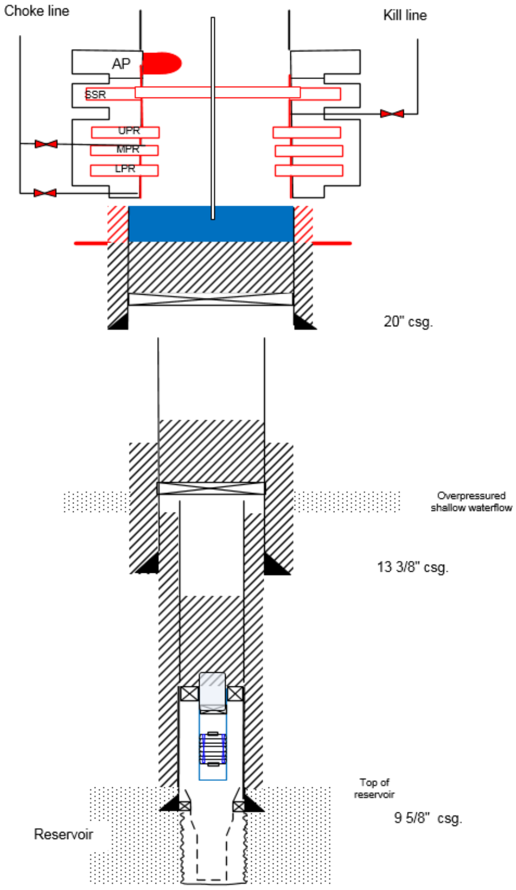
Figure 72 Cut and pull 13 3/8" casing

5.3.14 Open hole to surface barrier

Objective and activity

- Ref. to section 5.1.14

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore gas producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Fluid column	1	
SECONDARY		
Formation 20" casing shoe	51	
20" casing	2	
20 casing cement	22	.
20" casing hanger	5	
Wellhead	5	
BOP	4	

Notes:
1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" casing have confirmed good barrier cement

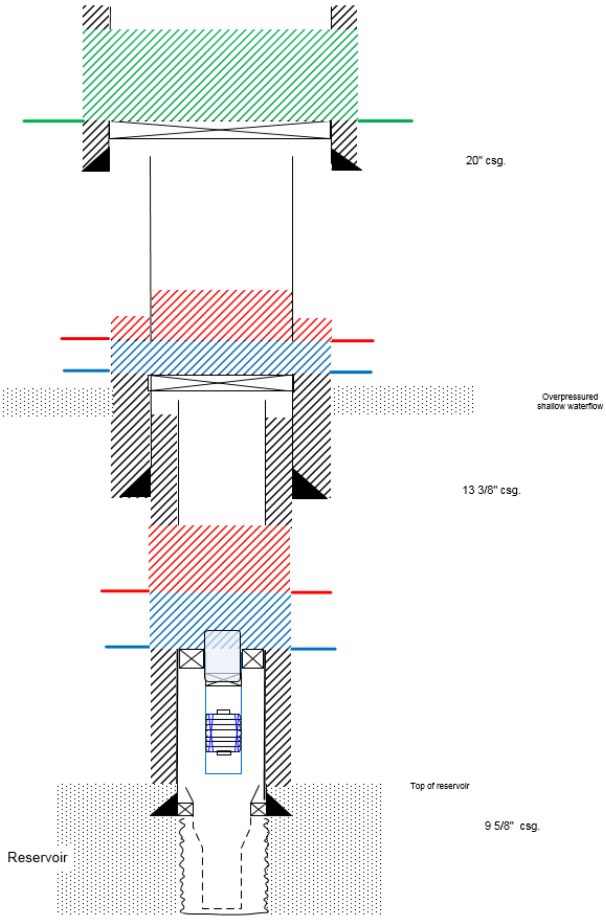
Figure 73 Setting open hole to surface barrier

5.3.15 Well status after permanent abandonment

Objective and activity

- Ref. to section 5.1.15

Barriers



Well data		
Installation/rig:	Gjøa	
Well no.:		
Well status:	Monobore oil producer	
Revision no. / Date:	1	21.04.2016
Prepared:	Krister Aunan	
Verified:		
Well barrier elements	**Ref. Table NORSOK D-010**	**Verification of barrier elements**
PRIMARY		
Formation at prod. Packer depth (Shetland)	51	
9 5/8" Casing cement	22	
9 5/8 " Casing	2	
Cement plug #1	24	
SECONDARY		
Shetland formation	51	
9 5/8" casing	2	
9 5/8" casing cement	22	.
Cement plug #2	24	
PRIMARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8" casing	2	
Cement plug #3	24	
SECONDARY (SWF)		
In-situ formation	51	
13 3/8" casing cement	22	
13 3/8 casing	2	
Cement plug #4	24	
Open hole to surface well barrier		
Casing cement	N/A	
20" casing cement	22	
20"casing	2	
Cement plug #5	24	
Notes: 1. USIT/CBL/VDL log of 13 3/8" casing and 9 5/8" liner have confirmed good barrier cement		

Figure 74 Permanently plugged and abandoned well

6 Discussion

The decision to P&A any well or a whole field is first and foremost based on economics. Once production delivers less revenue than the operating expenses, it is time to consider abandonment. The Cost of P&A operation can be calculated by multiplying abandonment time by the daily spread cost of the applied technologies. Saving a day means saving multiple million NOK. Therefore, in order to reduce the time and thereby the cost of abandonment operations, operators continuously strive to radically improve how P&As are performed. The service industry sees this as a major business opportunity for the not-to-distant future, and they are continually developing tools and techniques to decrease time/increase efficiency without compromising safety. Operators are to a lesser degree interested in the innovation itself, but are obviously keen to minimize money spent on a required P&A process that costs money but does not generate income. Minimizing operation time - and thereby costs - without sacrificing well integrity, is the most critical factor to the subsea operators, who by law are forced to make this significant investment with no financial return in the case of P&A operations.

This discussion chapter of my thesis will focus on some important aspects such as estimation of the time this process takes, and some areas of potential optimization or change.

6.1 Time Estimation

In this section a time estimation of the P&A operation for a single well, utilizing a semi-submersible for the operation, will be presented. For this purpose a probabilistic approach will be used with such advantages as reflecting model uncertainties, capturing an accurate range of possible outcomes, and promoting the understanding of unexpected events involved in the operation [27], compared to the deterministic method that is traditionally used. The P&A operation described in previous chapter can be further divided into sub-operations thereby defining a detailed operation plan. The various sub-operations, together with time distributions, are presented in table 7 below.

Table 7 Operation sequence for P&A of one single well at the Gjøa field

Description of operation	Minimum (hours)	Most Likely (hours)	Maximum (hours)
Anchoring of semi-submersible rig	18	22	28
Run WOR and connect to HXMT	48	60	72
Kill well, bullheading	6	9	12
Install and test deep-set plug	12	16	24
Punch tubing	12	14	18
Displace tubing and annulus	6	9	12
Install crown plugs	4	6	8
Pull WOR and run BOP	38	43	50
Pull crown plugs	4	6	8
Cut and pull tubing	48	62	78
Install shallow plug	6	8	12
Pull BOP and retrieve HXMT	36	41	48
Run drilling BOP	24	36	48
Retrieve shallow plug	6	8	12
Place cement plugs towards reservoir	22	26	30
Cut and pull 9 5/8” casing	24	30	36
Place cement plugs towards overburden	22	26	30
Cut and pull 13 3/8” casing	24	30	36
Set bridge plug	7	9	12
Setting open hole to surface barrier	18	24	36
Cut and retrieve WH	5	12	18
De-anchoring of semi-submersible rig	18	22	28

A Monte Carlo simulation is a method for investigating the probabilistic outcome of a process, and will forecast the total duration of the P&A operation. The procedure for time estimation of abandonment operations is based on the following steps [43]:

1. Define an appropriate model
    - Specify which items are included/excluded from the model.
    - The detail level of the model should be decided.
2. Data gathering
    - Set of collected data should be large enough to include all possible data.

   - Possible values for sub-operations are collected on the basis of historical data, phenomenology and expert opinions.
3. Define input distributions
   - Put effort and time in selecting appropriate mean and spread for inputs rather than discussing the distribution shape.
4. Sample input distributions
   - Choose how many iterations one requires: the larger the number of iterations, the more accurate estimate.
5. Interpreting and using the results
   - The output of the process will be a set of probability distribution curves or histogram for each forecast quantity.
   - This result needs to be evaluated and corrected if there are any mistakes.

MATLAB was used as the software-programming tool, and by running 30000 iterations the code generated the final results. The final time-distribution curves and corresponding statistical values for the scenario are presented in figure 75.

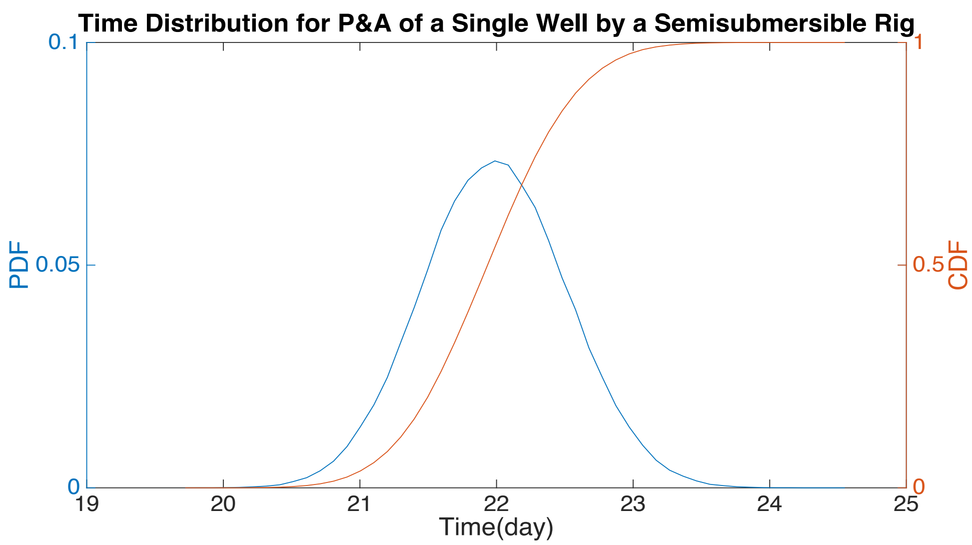


Figure 75 Time-distribution curve for P&A of a single well

The results of a probabilistic time estimation is presented as a probability-density function (PDF) and a cumulative-distribution function (CDF). The *x-axis* represents the time values for a single well abandonment, and the *y-axis* in the

PDF curve presents the occurrence probability corresponding to each value of the outcome, while the CDF curve shows the probability that the outcome takes a value that is less than the corresponding value on the x-axis [27]. From these resulting distribution curves, values of P10, P50 and P90 will also be obtained, seen in table 8.

- **P10** - 10 % of outcomes are smaller
- **P90** - 90 % of outcomes are smaller
- **P50** (Median) - 50 % of outcomes are smaller

Table 8 Statistical properties of the forecast result

Statistical Parameter	Total Time (days)
P10	21.31
P50	21.98
P90	22.67
Max	24.60
Min	19.68
Standard Deviation	0.53

The values obtained from figure 75 are not entirely realistic, as data from other elements, such as unexpected events and non-productive time (NPT) in the operation is not included. One significant advantage of the probabilistic approach is to quantify and manage the occurrence probability of unexpected events [27]. For further time estimation a more detailed analysis is required, which includes NPT and unexpected events such as WOW, not being able to pull tubing or casing, collapsed tubing or casing. This will have a negative effect in relation to time in the form of a more widened curve and a shift of the time-distribution curve to the right. This means that it is anticipated that the operation will take longer time and have a higher standard deviation, indicating that the data points are spread out over a wider range of values.

If, on the other hand, a multi-well campaign with sequential operations is planned, one could expect a learning effect to be gained from this. P&A time tends to decline with repetition of the same operations as learning is gained. This would be reflected in a more positive value with regard to time. The probability is that the next well be performed more effectively than the previous one.

Rushmore is a database that collects, analyses and publishes offset well data for participating operators in the oil industry. Based on data from P&A performed on 74 subsea wells on the NCS and the UK sector, the following percentage of productive time, WOW and NPT was retrieved, see figure 76. As one can see from the figure a lot of the operational time is lost on NPT and WOW.

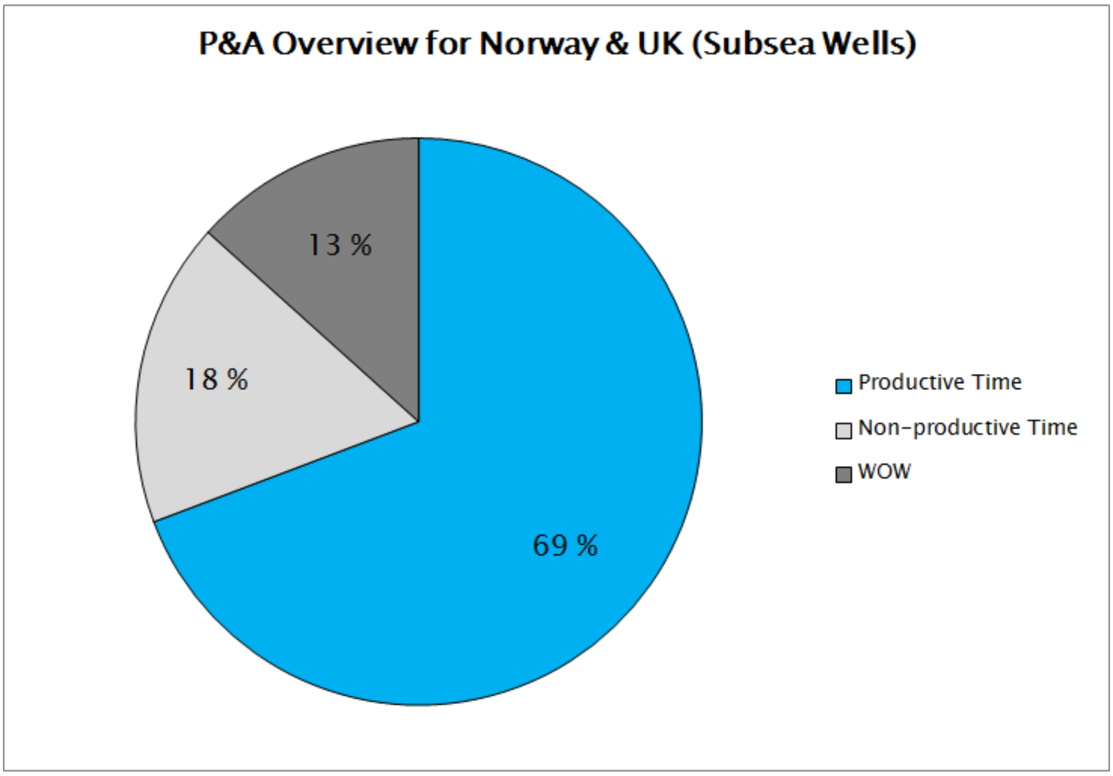


Figure 76 Productive time, NPT and WOW overview for P&A operations based on data from Rushmore

6.2 Innovative Technology

The O&G sector is a conservative industry, traditionally hesitant to implement new technologies and methods. However, as P&A creates no added value for the operators it is therefore reasonable to believe that the pace of technology development, and deployment around P&A operations should, and indeed must, accelerate in order to increase the effectiveness of abandoning wells. It is expected that the future will bring a strong focus on developing solutions that will compete to a lesser degree with the resources that are used for the permanent P&A of wells today. The traditional technology being used today is time-consuming and involves great challenges during operation. There are, therefore, major opportunities for innovative service companies to create revenue by promoting new technologies and methods, which will be efficient products for the oil companies.

In this chapter some of the potential new technologies will be addressed. If these technologies come out on the market, they have the potential to significantly improve and simplify the traditional P&A operation procedure, resulting in a paradigm shift in the traditional way of performing a P&A operation.

6.2.1 Interwell

Interwell is an international service company established in Norway in 1992, and they are currently working on developing what could be a transformative solution within P&A. Their method and use of permanently abandoning a well, or removing a well element, involves the use of a heat-generating mixture that melts the surrounding materials. The heat-generating mixture is positioned in the well, and by igniting the mixture all the surrounding materials in the well, including casings and tubing, will melt and create a barrier with properties similar to the cap rock [44].

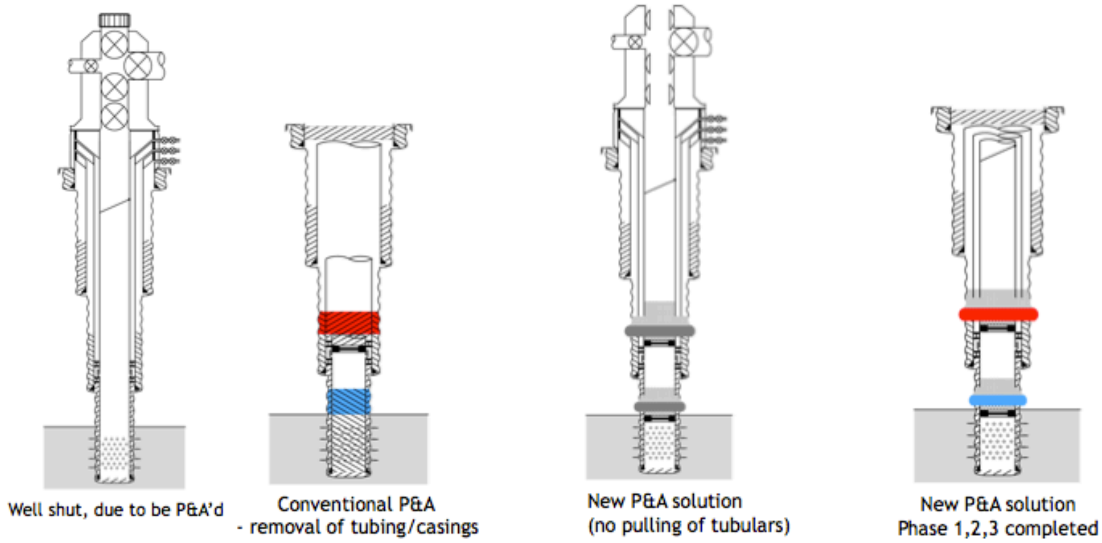


Figure 77 Current and new Interwell P&A practices [44]

Interwell has so far conducted over two hundred various scale tests, including multiple casing configurations, and completed its first recruitment to its operational/commercial organization. They are currently working to qualify their method in pilot wells, and hope to see their method commercially qualified through the end of 2016. Some potential advantages with their new technology are:

- Significantly reducing time and cost of P&A operation, eliminating time-consuming operation steps, reduce rig time and enable lighter vessels to perform the operation.
- Environmentally-friendly solution.
- Ensuring a permanent solution, claiming it has the ability to create a seal with zero leakage in an eternal perspective.

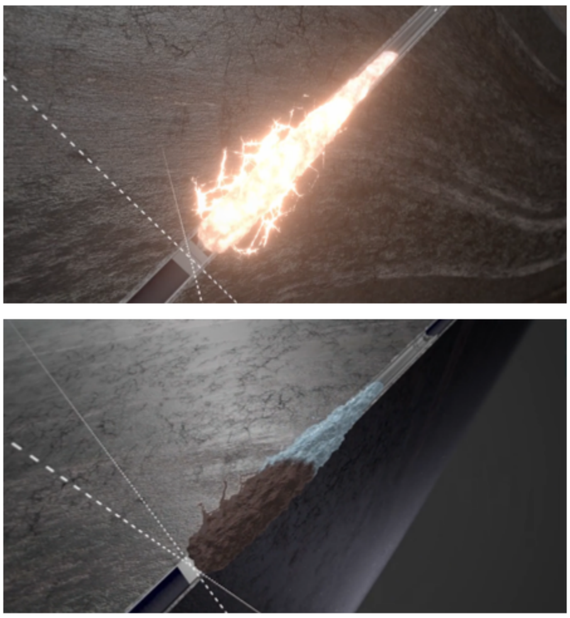


Figure 78 The goal is to restore reservoir barrier(s) with properties similar to cap rock properties [44]

6.2.2 Plasma-Based tool

GA Drilling is another service company focusing on developing ground-breaking technology within P&A. Their "solution" is the plasma-based tool still on the prototype stage. Two of the main P&A challenges are the time and expense of casing milling and swarf handling. Milling generates swarf, which must be removed before cementing, and removal of swarf can damage the BOP.

Plasma-Based tool technology is based on the production of high-temperature water steam plasma for rapid steel structural degradation [45]. This approach brings a radical abandonment of the classic rotary approaches involving connected tubes in a long string and the generation of swarf, both of which will be removed. This new technology eliminates the challenges described above, and it has the advantage of rig-less operation since the system is designed for coiled tubing solution.

The plasma-based tool is being developed for simplification of the conventional procedure. The tool should be able to operate through tubing without the need for XMT removal. This ability eliminates the need for tubing removal since the tool can mill tubing as well as casing in one trip. Some potential advantages with the Plasma-Based tool are:

- Rig-less operation because the system is designed for use with coiled tubing.
- Rapid structural degradation of steel with plasma enables a high milling rate of penetration. When compared with the conventional approach, this feature saves time because no tripping is needed.
- The mechanism produces tiny steel particles instead of swarf. This is beneficial for proper BOP operation, as well as for other components where swarf usually causes failures.
- The non-contact approach brings improved reliability by minimizing wear and tear of the tool.

6.2.3 The MicroTubeRemover Wellbore Intervention tool

In 2015, Aarbakke Innovation presented their latest tool for cost reduction in P&A. One of the challenges mentioned earlier, and one of the major reasons for using a rig for P&A, is pulling the production tubing. According to NORSOK, with regard to permanently abandoning a well, any micro tubes lines, sensor cables, chemical injection lines etc., outside the tubing must be removed in order to properly place a barrier material in the production annulus, as control lines cannot be part of a permanent barrier. The pending WL tool removes the micro tubes and brings them to surface allowing such a barrier placement to be done.

Figure 79 The MicroTubeRemover Wellbore Intervention tool [46]

The tool will locate production/injection tubing collars, and then locate micro tubes externally of the tubing, followed by cutting the lines above a cable protector. After this, the lines are grabbed, cut and retrieved from outside the tubing [46]. This will mean that use of a rig is unnecessary as there is no longer any need to pull the production tubing.

6.3 MODU vs LWIV

When planning the P&A operation the use of a MODU is the obvious choice, but further evaluation should be undertaken as to how the procedure can be improved by using more cost-effective vessels. There are some new technologies that could be adopted together with LWIV in order to improve the operational procedure. In this section some of the pros and cons of MODU versus LWIV will be discussed, as well as existing technical solutions that are achievable by the use of these.

6.3.1 P&A completed by MODU

The conventional vessel used for a P&A operation is a MODU, typically a traditional semi-submersible used to complete all phases. It is a safe option for any operator who will work with "as low as reasonably possible" (ALARP) as the main HSE principle, as it can easily handle foreseen and most unforeseen scenarios. This has also been the foundation of this study. A semi-submersible has many advantages compared to a LWIV:

- It can perform all P&A operations
- It can pull tubing and casing
- It is more suited if unexpected events occur during operations
- It is more robust to weather conditions
- It requires no extra mobilization of other vessels

However, as already mentioned, there should be increased focus on moving from these historically more expensive MODUs towards the increased use of LWIVs. During the last years the market has suffered some substantial changes when compared to previous years. Following the oil price drop, NCS activity has slowed down significantly, and the cost level has followed the trend. This applies to most cost elements, and in particular to rig rates. Admitting a long-term view that rates will remain at such levels is not entirely realistic, since this would reflect an unsustainable situation. The challenging task is to regulate the premise for the long-term assumptions, setting an economic environment today, for an operation that will take place long into the future. A more realistic (although conservative) prognosis could be to envisage a 30% reduction in the rig rates and 20% in service rates [47].

6.3.2 P&A completed by LWIV and MODU

The most likely method of performing subsea P&A jobs, with regard to the technology available and the striving for economical sustainability, is by transferring some of the activities in the operation from MODU to a dedicated LWIV. Statoil has already successfully used LWIVs for P&A jobs. This was done on five wells at Troll Oseberg Gas Injection, where some of the preparatory work of P&A, such as killing the well, punching the tubing and setting the temporary plugs, as well as removing the XMT, were conducted by LWIV. Afterwards, a semi-submersible performs the permanent P&A job by pulling the tubing, casing and installing permanent cement plugs. Statoil reported that the scope was completed with very good results, taking only 62.5 days rather than the 80 planned [48].

Suspended Well Abandonment Tool system from Claxton engineering has been used in many years in UK sector to establish the open hole to surface plug, deployed from a light construction vessel [49]. It is also possible to finish the P&A job by cutting and removing the WH, conductor and casing strings a few metres below the seabed by abrasive water jet cutting in combination with a Subsea WH Picker deployed from a vessel [2]. One modified and cost-effective phase approach with capable vessels could be done as follows[50]:

Preparatory work of phase 1: RLWI

- Well integrity testing
- Kill the well by bullheading
- Install and test deep-set plug
- Tubing punch and circulate
- Tubing cutting
- Set shallow temporary plug
- XMT removal

Phase 1: MODU

- Upper completion/tubing recovery
- Install shallow plug
- Section milling (if required) and casing retrieval
- Remedial cement operations
- Install permanent barriers

Phase 2: MODU and LWIV

- Install permanent barriers, MODU
- Setting surface barrier, LWIV

Phase 3: LWIV

- Cut and retrieve WH by an abrasive cutting technology in combination with a subsea WH picker
- Decommission and recovery of flowlines, umbilicals, etc.

6.3.3 P&A completed by LWIV

For the future the industry should strive towards removing the P&A activities from the use of semi-submersible rig to vessels. This should especially be possible on wells with a lower level of complexity. This will result in a significant cost reduction for operators, and will release semi-submersible rigs time to perform drilling operations. The main reason for the inability to use an LWIV to perform a full P&A operation is the lack of a riser. There are many challenges that need to be overcome before using an LWIV for full subsea abandonment [51]:

- Cement placement techniques for LWIVs (without riser)
- Tubing pulling from LWIV (without riser)
- General P&A challenges such as qualification of annulus barriers, tubing and casing integrity, collapses & restrictions, control lines etc.
- Reaching the target in the wellbores if the well is very deep and with a sharp angle. This has greatly improved after the WL tractor was taken into use.
- Not able to pump and circulate to perform sufficient well clean up.
- Weather limitation

- Working on live wells presents technical challenges because of the interface between high pressure HC and the low pressures on the vessel (less robust pressure control equipment compared to semi-submersible).

Wells vary largely in complexity and not all are suitable for rig-less P&A, but LWIV capabilities will increase over time (e.g. coiled tubing). There are many challenges that need to be addressed before using LWIV for full subsea abandonment, but the gains are so significant that there should be a collective industry pushing to make this possible in the future. In addition to the financial benefits to be gained by moving activities to dedicated vessels, there is a HSE benefit. Specialized personnel on dedicated vessels will conduct these transferred activities. On the rig these activities could be performed parallel to other rig activities and thereby represent a slightly higher HSE risk [2]. Some critical success factors for the striving towards realization of the rig-less potential are [51]:

- Operator involvement and commitment
    - Close dialogue between Contractors, Operator and Authorities
- Innovation and improvement thinking
    - More engineering studies are required
- Access to real wells for qualification of technology is essential
- Either making it easier to use LWIV w/riser, or being able to displace cement and pull tubing/casing without riser and still have full well control
- Integrating coiled tubing with LWIVs. Using coiled tubing without riser would be a significant improvement for riser-less LWIs
- Technology advances making it possible for LWIVs to perform more complex operations:
    - E.g. how to re-establish WBEs from LWIVs?
- Bridging the technology gap between LWIV and MODU for future subsea well abandonments, by constructing a heavy intervention vessel as an alternative approach for well P&A.

6.4 Batch operation

Batch P&A is usually performed in a field with multiple wells ready for P&A operation. While planning to P&A several wells on the Gjøa field that is located in the same template or nearby, it is possible to perform the P&A in batches in order to increase safety, and increase efficiency and therefore save money. A batch operation means that permanent abandonment for several wells can be planned consecutively. The eleven subsea wells on Gjøa have more or less similar abandonment needs and complexities. Therefore P&A of the wells could be done within a single campaign. This will result in a cost-effective P&A operation as the transit time from shore to the different well locations takes time. The cost of vessel mobilization and demobilization will be reduced for every additional well that is included in this batch operation. In addition, the experience gained from performing many operations will give an efficiency increase as a result of the learning curve gained by doing many wells in a row, resulting in improved work performance and reduced operating time.

6.5 Recommendation for future studies

For the proposed P&A operation itself, there are many steps that may be examined for improvement in order to make the procedure more efficient. In addition, further future study of some areas should be done before starting on the P&A process:

- One must go more into depth for each individual well, as the well integrity of each distinctive well will vary in regard to cement height, quality of cement, WH fatigue, well accessibility, minimum setting depth, depth uncertainty etc.
- Arguments could be made that it is not necessary to Bullhead/kill the well at all, but by using LWIV together with WL a deeply-set plug can be installed directly.
- It should be investigated whether an alternative could be to place cement plugs towards the reservoir during operation 5.1.7, after installing a mechanical plug inside the 9 5/8” casing, before installing a shallow plug.

- A WH fatigue analysis should be planned, and is indeed planned, before starting on the P&A operation to assess the structural integrity of the WH and casing system.
- More thorough research should be undertaken of the different service companies delivering different technologies with the potential for providing a more efficient process for each operational step. This research should embrace both current technologies and those to be developed in the future.
- Probabilistic time estimation has been introduced in this thesis, but as the P&A method selection has been improved a more thorough review should be conducted. Important parameters such as more detailed sub-operation division, NPT, unexpected events and batch operation must also be included to give a more realistic scenario of the expected operational time.

7 Conclusion

The subsea wells on the Gjøa field will have to be P&A'd due to declining O&G production. The Petroleum Act requires licensees to submit a cessation plan to the Ministry two to five years before the production licence expires, or use of the facility ceases. In this respect, the overall objective of this thesis, specified by ENGIE E&P Norge, has been to start on a preliminary discussion of the process on how one can permanently P&A the wells in accordance with applicable regulation(s), which in the case of P&A is NORSOK D-010.

A step-by-step approach has been suggested, clearly presenting the different operations with the purpose of being easy to follow and understanding the actual operational process. Much emphasis has been brought into drawing WBS in Microsoft Visio showing the primary and secondary barriers during each step of the operation. These schematics are widely implemented and used in the industry. In particularly, they are used during operations on offshore facilities, to clearly identify each WBE together forming the primary and secondary envelopes. In this way it is easy to consider the safety of a well and its well barriers for those performing the operations and potential stakeholders. It has also proved to be useful and informal to use the illustrations in discussions when considering different solutions.

In addition to the reservoir, one overburden zone that is considered as a potential source of inflow has been identified; therefore, this also must be P&A'd with primary and secondary well barriers. These plugs shall seal the wellbore and all annuli in all directions. Because of this over-pressured zone in the overburden, both the 9 5/8" casing and the 13 3/8" casing must be cut and pulled in order to put in place satisfactory well barrier plugs.

On the Gjøa field, where there has been forward thinking, and where a thorough job has been done during the well design and drilling of the wells, the P&A operation itself would appear to be pretty straightforward. The most successful and economical approach is to avoid remedial cementing by thoroughly planning, designing, and executing all drilling, primary cementing, and completion operations properly. A good primary cement job is crucial for simplifying the procedure, and logging of the casing cement has confirmed that most of the wells have verified good-cement behind the casing. Therefore, it would seem that milling is not required, this being one of the most time-consuming P&A operations. The wells on Gjøa field are not old, with the first well being drilled in the beginning of 2009, and currently none of them has well integrity issues of significance for the P&A operation itself.

The actual P&A method used in the future may deviate, or at best, be improved from the one proposed in this thesis, but findings show that a similar operational procedure can be performed for each of the three different types of well design. However, future studies must go more into depth on each well, as each well is unique with regard to depth variations, cement heights, integrity issues etc. The latter are important parameters that have not been considered in depth in this thesis, and there might be slight variations on a well-to-well basis.

As there has been increasingly more focus on P&A, new technology will emerge, and this will have the potential to make step changes in the traditional way of performing a P&A operation today. New technology will mean that undesirable and time-consuming operations, such as milling, pulling tubing, cutting and pulling casing, may be performed by LWIV, or at best can be avoided. This would mean enormous cost reductions for the operators and, at the end of the day, Norwegian taxpayers. Worldwide, service companies are developing tools and methods to limit the economic impact of fulfilling these obligations. As technology keeps improving and P&A is getting ever-increasing attention as a potentially profitable option for service companies, new solutions are arising.

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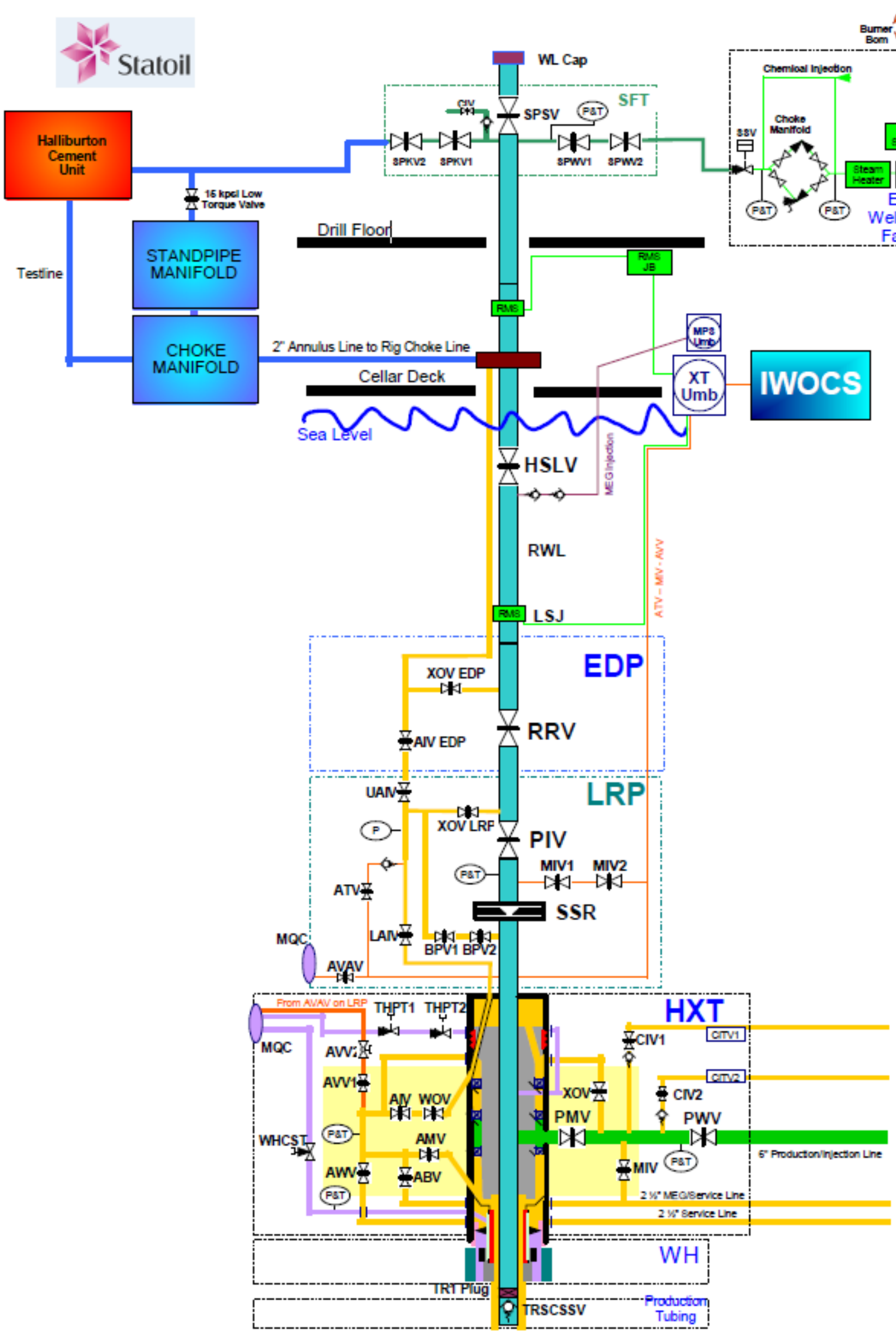
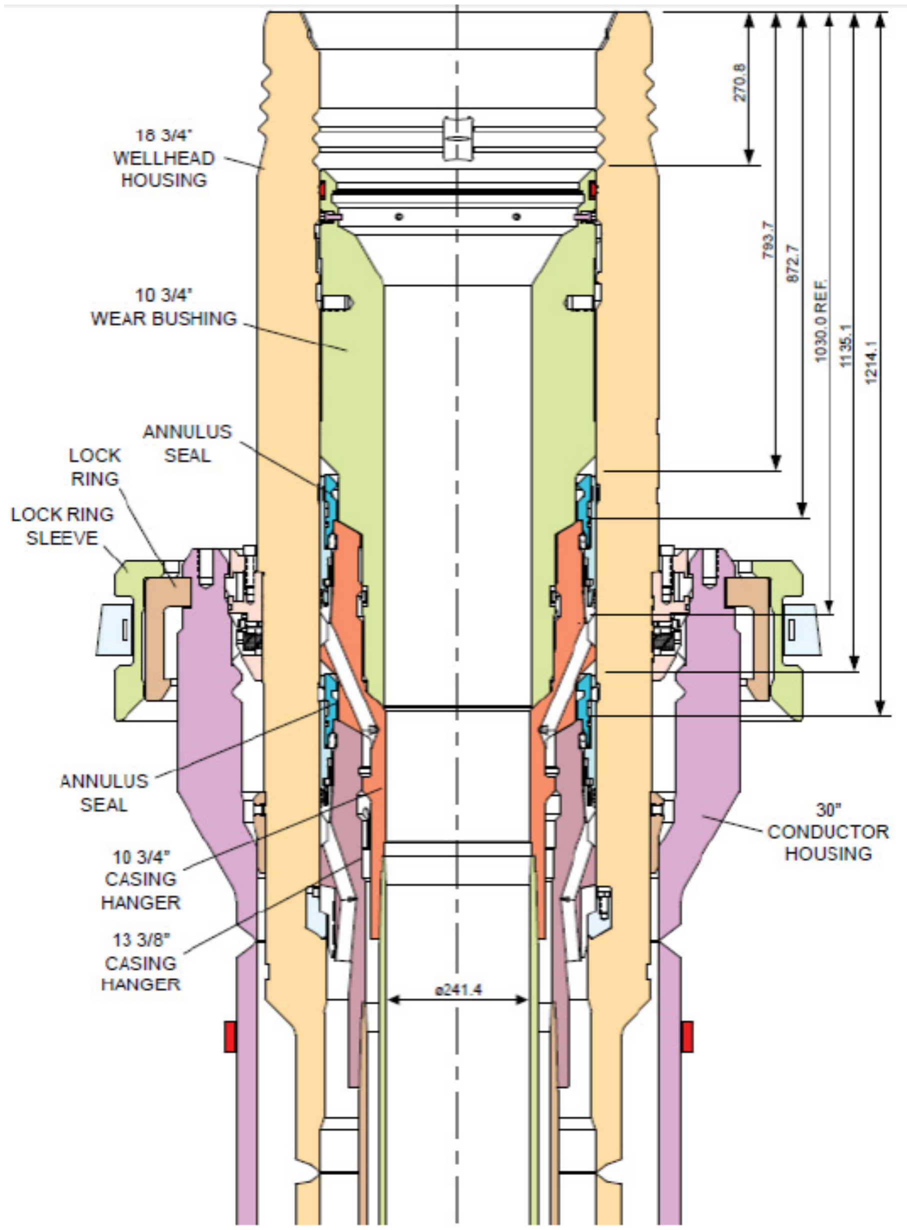
Appendix A

Workover Riser system used when drilling the wells on Gjøa [11]



Appendix B

Cross sectional schematic of Wellhead on Gjøa wells [11]



Wellhead in 30" Conductor Housing Stack up

Cross sectional schematic of HXMT on Gjøa wells [11]