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Abstract

The production on several fields on the Norwegian continental shelf (NCS) is moving towards the critical point where expenses exceed the production income. Operating past the economical limit is not viable and thus, the operator may be forced to permanently abandon the wells. The process of abandoning a well, commonly referred to as Plug and Abandon (P&A), has been given a lot of attention in the industry recently. This relates to the expected prohibitive cost that will, in addition to impacting the operators and license partners, affect the Norwegian taxpayers.

Due to the large uncertainties related to any well operation, the establishment of accurate and reliable cost and time estimates are important, both in relation to the asset retirement obligation, and for achieving an approval for the expenditures. Traditionally, time estimates have been conducted in a deterministic way. However, performing probabilistic time estimation may provide several advantages in terms of expressing the uncertainties and understanding the risks that are associated with a project [7].

The task provided by Wintershall was to establish a probabilistic time estimate of the P&A for one of their operating fields, Brage. Since the peak in 1996, the production on Brage has been decreasing and is predicted to be shut down in 2030.

The wells on Brage have been categorized in terms of casing design and required abandonment operations. Based on this categorization, 12 operational procedures have been established to serve as basis for the time estimates. A probabilistic model including risked events and learning curve has been established and by performing a sensitivity analysis, the most critical operations have been identified.

Using this model, P&A of the 40 wells on Brage is estimated to last for 960 days. The importance of including learning and unplanned events can be seen through the effect on the time estimates. In addition, the sensitivity analysis has identified the most critical part of the P&A project, namely the uncertainty related to the green clay's bond to casing. The operations related to section milling and retrieval of tubulars are also subject to uncertainty and could potentially cause severe non-productive time events.

To reduce the risks related to the future P&A project, technologies such as SwarfPak by WestGroup, HydraHemera by HydraWell and Sabre cutting system provided by Claxton should be followed up and evaluated.

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List of abbreviations

AFE - Authorization for Expenditures

ASV – Annular Safety Valve

BOP – Blow Out Preventer

CBL – Cement Bond Log

CTA – Concentric Tubing Anchor

DHSV – Downhole Safety Valve

EAC – Element Acceptance Criteria

FIT – Formation Integrity Test

HSE – Health, Safety and Environment

LOT – Leak-off Test

NCS – Norwegian Continental Shelf

NORSOK – Norsk Sokkels Konkurranseposisjon (The Norwegian Shelf's Competitive Position)

NPT – Non-Productive Time

P&A – Plug and Abandon

PSA – Petroleum Safety Authority (Petroleumstilsynet)

PWC – Perforate, Wash and Cement

RLWI – Riserless Light Well Intervention

TVD – True Vertical Depth

USIT – Ultrasonic Imager Tool

WBE – Well Barrier Element

WBS – Well Barrier Schematic

WH – Wellhead

WOW – Waiting on Weather

XLOT – Extended Leak-off Test

XMT – Christmas Tree

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1 Introduction

1.1 Background

Since the start up in 1966, a total of 6283 wells have been drilled on the Norwegian Continental Shelf (NCS). This number includes development wells and exploration wells drilled at the North Sea, Norwegian Sea and Barents Sea [1].

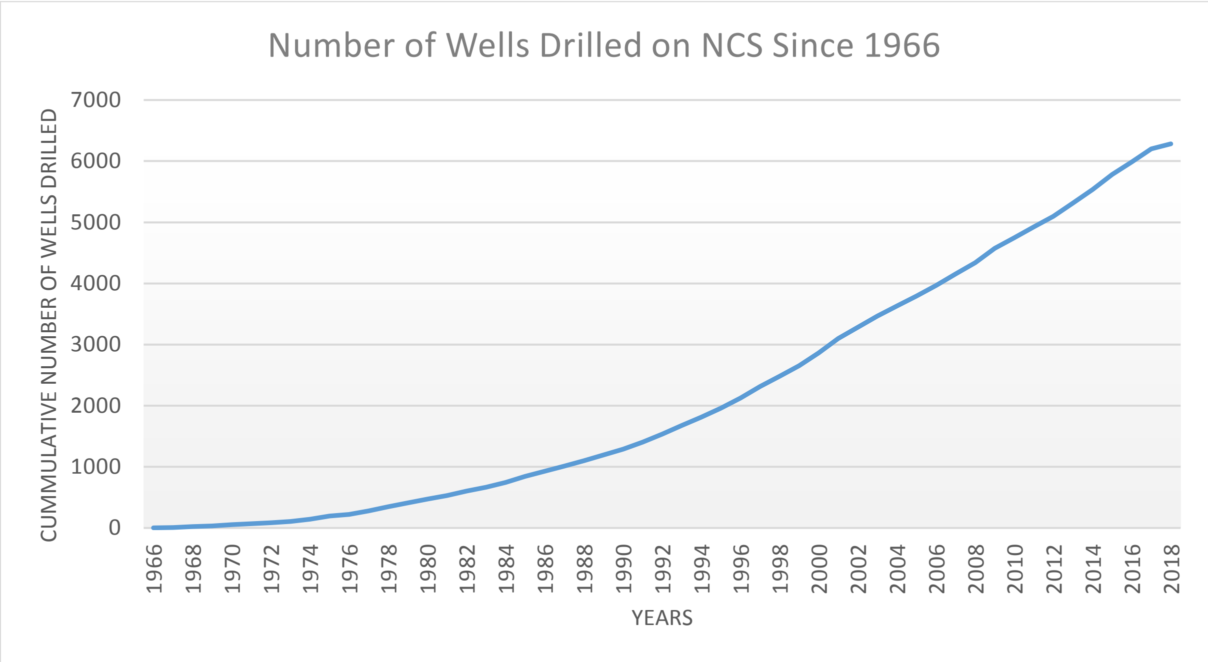


Figure 1: The Number of Wells Drilled on the NCS Since 1966 [1]

The lifetime of a typical oil field can be described through Fig.2 below. At the first stage, the petroleum deposit is discovered by a wildcat well. Exploration wells, also known as appraisal wells, are then drilled to identify the extent and size of the deposit before the final production wells are drilled. The production builds up until it reaches a steady state. The production remains at this plateau for a while before it eventually starts declining. As the production diminish towards an economic limit, the wells are moving towards its last phase, the abandonment phase [2]. The economic limit is representing the point in production where the expenses exceed the income [3]. If the operator finds it plausible that production from other parts of the field will be profitable, wells may be temporary abandoned and re-entered at a later stage. For the case with no further benefits of re-entries, the well will be closed for production and permanently abandoned. This process is referred to as plug and abandonment (P&A).

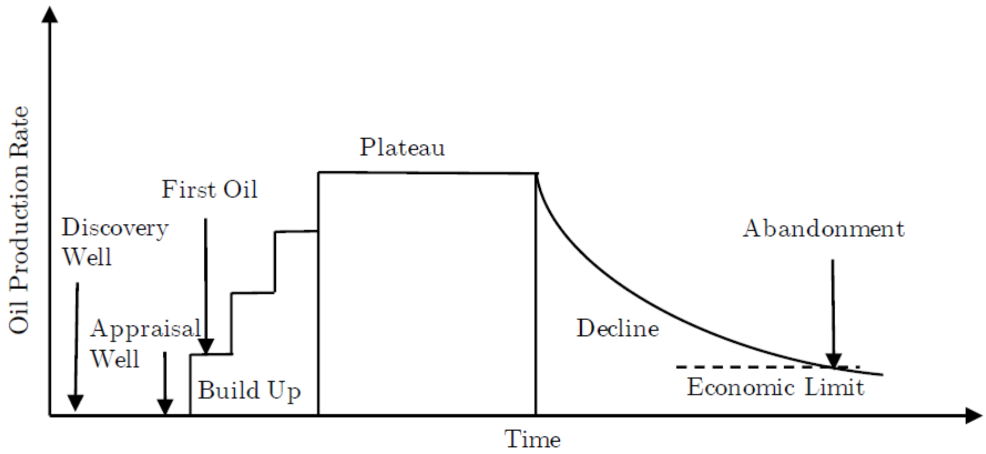


Figure 2: The Lifetime of a Typical Oil Field, from discovery to abandonment [2].

The objective of the P&A phase is to seal off the well to prevent leakages of hydrocarbons to the surface and cross-contamination of liquids between different formations. The seal is obtained by installing barriers in the well, and shall be installed with an eternal perspective [4].

A study conducted in 2015 showed that among the 5768 wellbores drilled up to that date, only 3223 had been P&A'ed [5]. Fig.3 presents the well status on the NCS from 2015. From 2015 and until today, 515 new wells have been drilled [1]. This implies that sooner or later, thousands of wells must be P&A'ed.

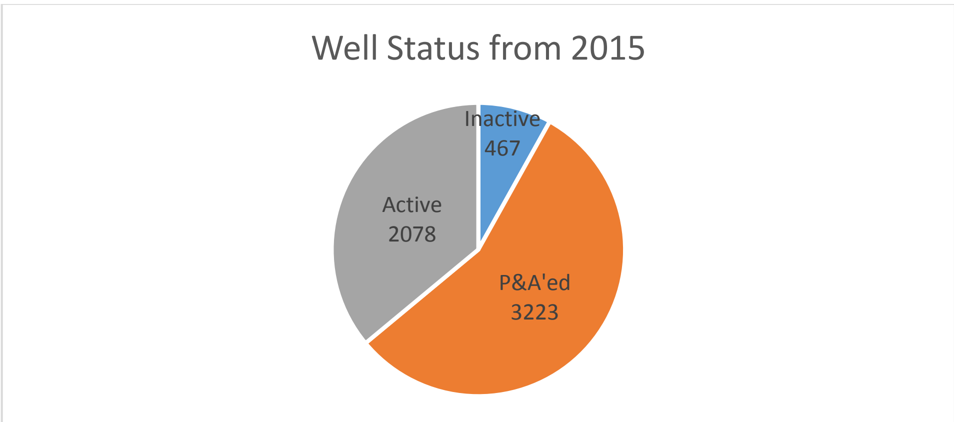


Figure 3 Wells Status on NCS from a study in 2015 [5]

The P&A cost can easily account for as much as 25 % of the total cost for exploration wells [6]. Furthermore, the study from 2015 predicted a cost of P&A on the NCS of 571 billion NOKs [5].

As 78% of the cost falls on the Norwegian taxpayers, cost reducing measures should be of interest for everyone. Today, with the increased focus on P&A, several companies are expanding within the P&A market by providing new and promising technology. By conducting early assessment of the future P&A projects, in terms of identifying the required barriers, revealing the time-driving well operations and investing in innovative technology, a reduction in cost and duration could be plausible.

In the planning phase of a P&A project, time and cost estimations must be conducted. This is one of the main step leading to an approval of Authorization of Expenditure (AFE). Traditionally, time and cost estimation has been conducted in a deterministic approach. I.e. a single well cost and duration estimate has been provided. However, for the drilling engineers to identify the potential time-drivers in a P&A campaign and to establish a basis for decision making, proper estimation models that provides clear and transparent information regarding uncertainty are essential. By applying probabilistic estimation models, this could be obtained with more ease [7].

1.2 Definition of Thesis and Research Questions

The production on Brage has naturally been declining since the peak in 1996. This is illustrated in Fig.4 below. The long tail in the production on Brage compared to the shorter tail in Fig.2, implies that injection has been applied to enhance the production and that several side-tracks have been performed to target other producing zones. A production moving towards the economic limit implies that operators should start on the preliminary assessment of the operation companies often prefer to postpone, the P&A phase.

According to Wintershall, the production on Brage is presumed to last until 2030. A decommissioning plan shall be submitted between two and five years before the expected P&A execution [8]. This imply that a plan on Brage shall be submitted between 2025 and 2028, which is respectively 7 and 10 years ahead. However, preliminary assessment of well status, required operations and potential new technologies may provide an advantage when the planning starts.

The task provided by Wintershall was to establish a probabilistic time estimate of the P&A for the wells on Brage. The objective of the thesis is to establish a time estimation model that includes risk, in terms of unplanned events and general Non-Productive Time (NPT). In addition, learning shall be implemented to the model to assess the effect of improvements on a multi-well P&A project. One of the benefits with the probabilistic approach is the ability to present the well operations subject to uncertainty with ease [7]. This can further be used in early allocation of resources and to identify the potential upsides in applying innovative technology. Hence, a sensitivity analysis of the different well operations will also be considered in the thesis.

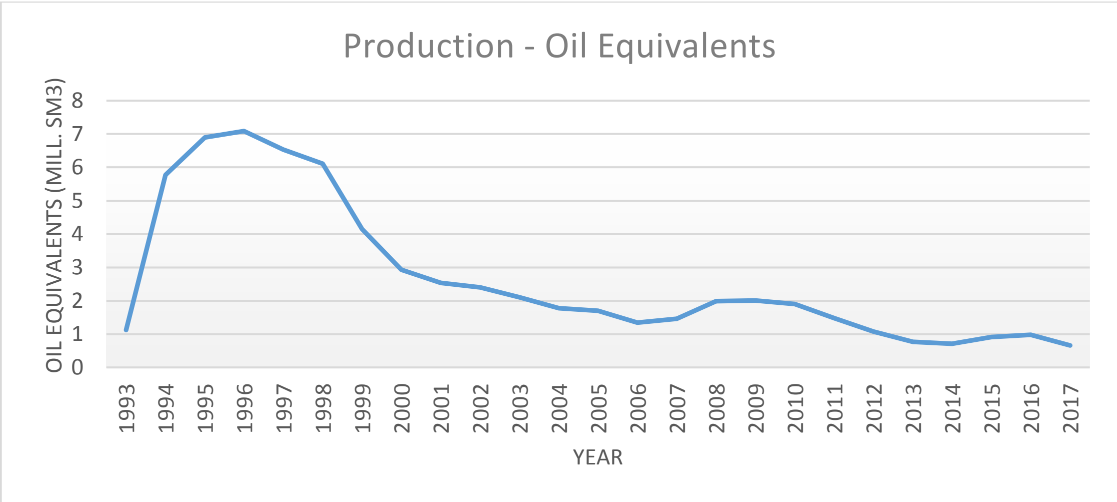


Figure 4: Production of Oil Equivalents on Brage since 1993 [9]

The estimation model established in this thesis will be based on a categorization of the different wells on Brage. This categorization will serve as a base for the work breakdown structure of the different well operations required for P&A. The work breakdown structures will be assigned operational procedures that cover each well category. Monte Carlo simulations will then be applied to the different procedures to establish a probabilistic time estimate. The proposed procedures will be based on regulations on the NCS, guidelines in NORSOK, the distinct well designs and previously established procedures.

The input data used in the simulations are mainly based on historical data from similar activities conducted on Brage. These relate to the operations conducted when old wells have been plugged back and re-entered. In addition, some input data are based on expert opinions from drilling engineers at Wintershall. Duration data from the decommissioning project of the Murchison field on UK sector are also considered. These are applied to cover well activities not yet performed at Brage and to evaluate the effect of learning.

To summarize, this thesis aims to answer the following questions:

- How do we develop a probabilistic estimation model that includes both learning and unplanned events?
- What is the estimated duration of P&A of the wells on Brage?
- How will the inclusion of uncertainties and learning affect the time estimate?
- Which operations are exposed to most uncertainty and thus, should be given sound effort in the future?
- Which operation could benefit from innovative technology?

1.3 Structure of Thesis

The remaining part of this thesis will be structured in the following way:

- **Chapter 2** defines and describes the phases of P&A, along with a review of the regulations and guidelines associated with P&A on NCS. In addition, general challenges and technology will be presented.

- **Chapter 3** gives a review of the theory behind probabilistic estimation and a walkthrough on how to develop a probabilistic model. The chapter also presents the method for including unplanned events and learning.

- **Chapter 4** will present some general information regarding the Brage field.

- **Chapter 5** will review the proposed P&A method on Brage and relate to the establishment of the different well categories and procedures. This chapter will also consider the possible unplanned events associated with P&A on Brage.

- **Chapter 6** will consider the method for collecting adequate input data. The use of expert opinions will also be discussed.

- **Chapter 7** explains the different models established for conducting the estimation.

- **Chapter 8** presents some of the results from the simulations conducted.

- **Chapter 9** relate to the discussion part of the thesis. The discussion is based on the validity of the estimates, along with assessment of the most critical operations. Potential upsides provided by innovative technology will also be discussed.

- **Chapter 10** aims to summarize and conclude based on the questions raised in section 1.2. Recommendations for further research are also presented.

2 P&A Theory

As shown in Fig.2, the income from a producing well will at some point fail to cover its expenses. The operator will now be left with different options. By plug back the original wellbore and perform a sidetrack, the operator could target either a more profitable part of the reservoir or a nearby located reservoir. If this is not possible, the wellbore must be plugged and abandoned, either in a temporary or a permanent perspective. P&A involves the activities conducted when shutting the well for production. The overall goal of P&A is to prevent any leakages of pore fluids to the environment [4]. In addition to the requirements related to the final well-status, the P&A activities performed in advance are also governed by a set of rules, regulations and guidelines introduced by the Norwegian government.

In this chapter, some general P&A theory will be presented. This will include definition, the governing regulations and standards and the phases of well abandonment. Some general challenges and technology associated with P&A will also be presented.

2.1 Definition

NORSOK [4] divides plug and abandonment into temporary and permanent abandonment. Temporary abandonment is further categorized to capture the presence of barrier monitoring.

a) ***Temporary Abandonment with Monitoring*** – "*Well status where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested. If the criteria cannot be fulfilled, the well shall be categorized as a temporary abandoned well without monitoring. There is no maximum abandonment period for wells with monitoring" [4, p. 14]*.

b) ***Temporary Abandonment without monitoring*** – *"Well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and not routinely tested. The maximum abandonment period shall be three years" [4, p. 15]*.

c) ***Permanent Abandonment –*** "W*ell status, where the well is abandoned and will not be used or re-entered again [4, p. 12]*.

The categorization presented above is based on the D-010 standard [4], provided by NORSOK. The NORSOK standards were established to provide a common set of standards to serve as reference in the authority's regulations, and will be described further in section 2.2 [4]. For the remaining part of this thesis, the term P&A will refer to as permanent P&A.

The operations involved in a P&A project will vary from one field to another. However, the general operational steps normally include [10]:

1) Connection to wellhead/X-mas tree (XMT) and killing the well.
2) Removal of XMT.
3) Cut and pulling of production tubing.
4) Installing well barriers.
5) Cut and retrieval of the wellhead, casing strings and conductor.

The operational steps presented above will include several sub-operations that will depend on the given well scenario. A more detailed description of the required operational steps will be presented in Chapter 5.

2.2 NCS Regulations and Guidelines

Several regulatory bodies are established to ensure adequate safety in P&A operations on the NCS. Fig.5 illustrates the governing hierarchy on the NCS. All well activities on the NCS shall be performed in accordance with the Petroleum Act of 29 November 1996 [8], which is regulated by the Petroleum Safety Authority (PSA). Section 5-1 of the Petroleum Act relates to the decommissioning plan and states that a plan shall be submitted between two and five years prior to the expected field decommissioning [8].

The PSA is an independent government regulator and issues regulations and guidelines that promotes safety in the Norwegian petroleum industry [11]. To succeed in the requirements in these regulations, the related guidelines often refer to standards such as NORSOK, American Petroleum Institute (API) and standards issued by DNV GL [12]. As the operational procedures established in this thesis are based on the NORSOK D-010 standard, this will be further presented in the next section.

p. 16].

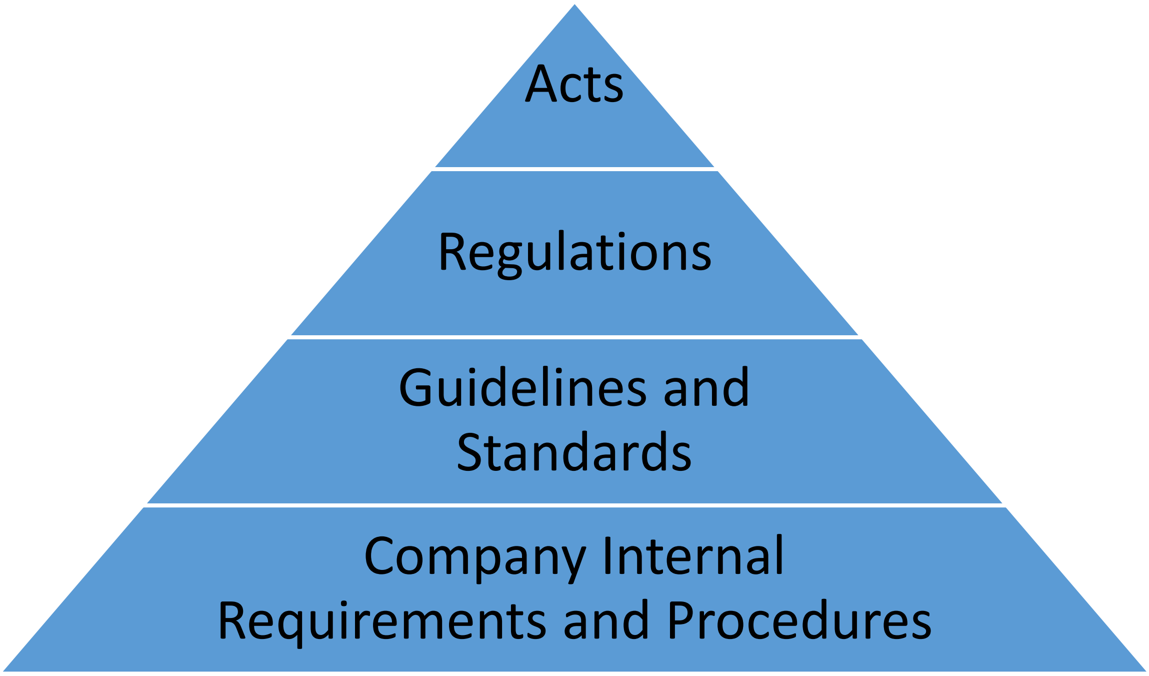


Figure 5: Governing Hierarchy in the Norwegian Petroleum Industry [11]

2.2.3 The NORSOK Standards – D-010

The NORSOK standards were first developed in 1994 through a collaboration between the Norwegian Petroleum industry and the government. At that time, companies used different standards that were often based on, the not necessarily comparable, US. standards. To replace each company`s individual standards with a common set of standards to serve as reference in the authority's regulations, the NORSOK standards were established. The purpose of NORSOK is to add value, reduce costs, increase safety and eliminate unnecessary activities in offshore field developments and operations [13] [4].

One of the resulting NORSOK standards is NORSOK D-010. The D-010 serves to establish requirements and guidelines for proper *well integrity* in drilling and well operations [4]. Well integrity is defined as *"application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well"* [4, p. 16].

In relation to well abandonment, the NORSOK D-010 provides requirements and guidelines for establishing barriers and other related activities conducted. In this section, these requirements will be discussed as the P&A proposal for Brage will be in accordance with this standard. The general requirements and guidelines for well integrity will be explained first, before describing the requirements for the specific case of well abandonment.

Before moving into the different requirements, it is worthwhile to define some key terms used in NORSOK. The definitions are found in Section 3.1 in NORSOK D-010 [4].

Well Barrier: *"envelope of one or several well barrier elements preventing fluid from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment"* [4, p. 15].

Well Barrier Element (WBE): *"A physical element which in itself does not prevent flow but in combination with other WBE`s forms a well barrier"* [4, p. 15].

Source of inflow: *"a formation which contains free gas, movable hydrocarbons, or abnormally pressured movable water"* [4, p. 14].

Shall: *"Verbal form used to indicate requirements strictly to be followed in order to conform to this NORSOK standard and from which no deviation is permitted, unless accepted by all involved parties"* [4, p. 14].

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 of action is preferred but not necessarily required"* [4, p. 14].

2.2.3.1 General Well Barrier Requirements

Identifying Required Well Barriers

Before an activity or operation can be conducted, the well barriers *shall* be defined. This is obtained by evaluating the required WBE forming the well barrier envelope. The well barriers *shall* fulfill several requirements regarding design and installation. These requirements relate, among others, to the pressure and environment it will be exposed to, dependencies between the different WBEs and so on [4]. A list of these requirements will be listed in Appendix A. The required amount of well barriers in place before commencing a well activity, depend on the source of inflow. Table 1 below, obtained from D-010, presents the minimum number of well barriers for different source of inflow [4].

Table 1: Minimum number of well barriers for various sources of inflow [4]

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

We see that the required amount of well barriers relate to both the formation pressure and the potential of fluid flow to surface. For wells with hydrocarbon bearing formations, or highly pressured formation where flow to surface is likely, two well barriers *shall* be in place. The two well barriers are referred to as the *primary* and *secondary* barrier and can be described in the following way [4]:

Primary Well Barrier - the well barrier that first prevent the unintended flow of fluids. That is, the well barrier closest to the source of inflow.

Secondary Well Barrier - the second, or back-up, well barrier that intend to prevent the unintended flow of fluids.

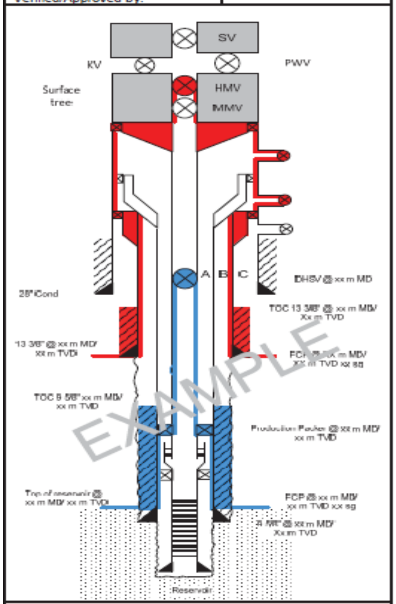
Well Barrier Schematic (WBS)

Before a well activity is commenced, a Well Barrier Schematic (WBS) *shall* be prepared. The WBS *should* among other include drawings of the well with the required barriers and WBE, potential sources of inflow, casings and the casing cement and the presence of failing WBE. In addition, it must contain well information and be clearly stated if the WBS is a planned or as-built version [4]. An example of a WBS is shown in Fig.6 below.

One column also worth mentioning is the Elements Acceptance Criteria (EAC). The number presented in this column refers to Chapter 15 in NORSOK D-010 and lists distinct technical and operational requirements related to the WBE for different well activities [4].

The WBS presented below only forms as an example, and a distinctive WBS must be developed when a new WBE is installed, the completed well is to be presented, workover is to be conducted, or to illustrate a permanent abandoned well [4].

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



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

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

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

Figure 6: WBS for a production well with potential of fluid flow [4].

Fig.6 illustrates a production well with potential of fluid flow. We see that the different WBE are listed under their associated well barrier, either the primary or secondary. The drawing distinguishes between the primary and secondary well barrier by assigning a blue and red color respectively.

The requirements and guidelines presented above form the general principles. Later chapters of NORSOK D-010 describe requirements and guidelines for specific operations, e.g. the activities related to the abandonment of a well. If requirements from the generic section are against those presented in the specific section, the specific should be the one counting [4].

2.2.3.2 Well Barrier Requirements for Permanent Abandonment

Chapter 9 in NORSOK D-010 covers the requirements and guidelines pertaining to well integrity during abandonment activities. The chapter covers activities related to suspension of well operations, temporary abandonment, permanent abandonment, and plug-back of wells before sidetracking. The purpose of Chapter 9 is, as for Chapter 4, to explain the creation of well barriers required to conduct the operations in a safe way.

Well Barrier Acceptance Criteria

As previous explained, a well barrier consists of several WBE. The required WBE may be different for permanent abandonment activities than for temporary abandonment activities. This is related to the definition of permanent abandonment; *"well status, where the well is abandoned and will not be used or re-entered again."* [4, p. 12]. The wells *shall* be plugged with an eternal perspective and hence, the well barrier *shall* withstand chemical and geological alterations. NORSOK does not specify which material to be used as a well barrier. However, Section 9.6.2 in NORSOK D-010 does provide a detailed list of the required *properties* of a well barrier. The barrier should [4]:

- Have an eternal perspective.
- Be impermeable.
- Be non-shrinking.
- Withstand mechanical impact.
- Be resistant to chemicals/substances.
- Ensure bonding to steel.
- Not be harmful to the steel tubulars integrity.

The required number of well barriers is, as for the generic section, explained through Table 1. In addition, requirements regarding barriers preventing flow between formation and "an open hole to surface" well barrier, are considered for permanent abandonment. The "open hole to surface" well barrier is often referred to as the *environmental plug*. Table 2 describes the resulting well barriers from the abandonment activity, along with their function and depth requirements. The crossflow barrier is only applicable for wells containing multiple source of inflow with different pressure regimes. If this is the case, the crossflow barrier can act as the primary barrier for the reservoir below. When the pressure regime is identical, the two sources of inflow can be treated as one, and the crossflow barrier is not necessary [4].

Table 2: The resulting well barriers from abandonment activities [4]

Name	Function	Depth position
Primary well barrier	To isolate a source of inflow, formation with normal pressure or over-pressured/ impermeable formation from surface/seabed.	The base of the well barriers shall be positioned at a depth were formation integrity is higher than potential pressure below, see 4.2.3.6.7 Testing of formation.
Secondary well barrier	Back-up to the primary well barrier, against a source of inflow	As above
Crossflow well barrier	To prevent flow between formations (where crossflow is not acceptable). May also function as primary well barrier for the reservoir below.	As above
Open hole to surface well barrier	To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.	No depth requirement with respect to formation integrity

Table 2 indicates that the well barrier *shall* be placed at *"a depth where formation integrity is higher than potential pressure below [4, p. 95]."* The formation integrity is normally based on previously conducted formation integrity tests (FIT), leak-off tests (LOT) or extended leak-off tests (XLOT) [4].

To be recognized as a permanent well barrier, the barrier *shall* extend across the full cross section of the well. The barrier *shall* extend through each annulus and seal in both vertical and horizontal direction. Thus, if a barrier is placed inside a casing with insufficient casing cement bonding, it is not recognized as a barrier. A valid well barrier is presented in Fig.7, where a cement plug is set inside a casing with sufficient cement bonding behind [4].

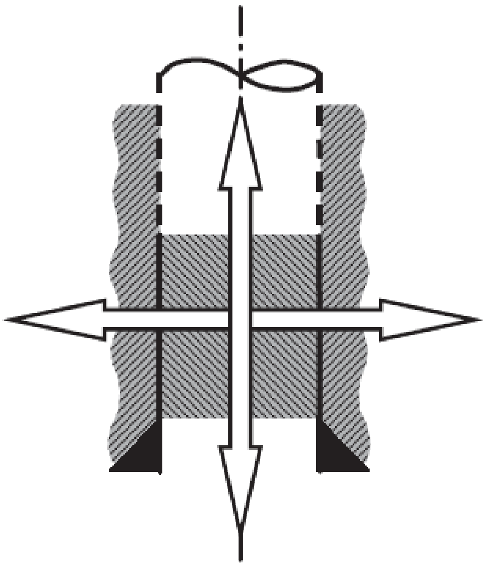


Figure 7: Well barrier sealing requirements - Cement Plug [4]

In Fig. 7, the inside cement plug acts as an internal WBE while the outer casing cement acts as an external WBE. For both the internal and external WBE, cement is the preferred material in the industry. However, other materials satisfying the list presented above can also be applied. Regarding the external WBE, impermeable formations with the ability to creep and form sufficient bonding with the outer casing, can in some cases act as a permanent WBE [4]. This will be discussed later in this chapter.

Both the external and the internal WBE *shall* have sufficient length and be verified to act as a well barrier [4]. The requirements regarding verification and length will be described in the following.

Length and Verification Requirements of an External WBE

A verification of the External WBE is required to confirm sealing in both vertical and horizontal direction. The verification can be based on either logging or historical records from cement jobs regarding volumes pumped, returns, etc. Logging *shall* be conducted if the casing cement is a part of both primary and secondary well barrier [4].

The required length of an external WBE is 50 m of acceptable bonding and formation integrity at the base of this interval. If the casing cement has been verified by logging, 30 m of acceptable bonding is sufficient [4]. If the formation is used as external WBE, other requirements are applicable. These will be described later in this chapter.

Length and Verification Requirements of an Internal WBE

If the internal WBE (e.g. a cement plug) is placed in a **cased hole**, the plug *shall* be verified by both tagging and pressure testing. If a pressure tested mechanical plug is used as foundation for the cement plug, it is sufficient to only verify the cement plug by tagging. If a continuous cement plug is acting as both primary and secondary well barrier, the plug *shall* be verified by drilling until hard cement is encountered. When the cement plug is placed in **open hole**, the barrier *shall* be verified by tagging [4].

Regarding the required lengths, the **open hole** cement plug *shall* be 100 m MD, with a minimum of 50 m MD above any source of inflow point. If the setting interval of the plug extends from open hole to casing, the plug should extend minimum 50 m MD above and below the casing shoe. If the cement plug is placed in a **cased hole**, the length *shall* be minimum 100 m MD, or 50 m MD if the plug is placed on a foundation plug. The **open hole to surface** plug has the same length requirement as for the **cased hole** plug [4].

Removing equipment above seabed

When all required well barrier has been placed, the process of removing equipment above seabed commence. NORSOK states that the wellhead, conductor and casings *shall* be removed a few meters below the seabed. This is to prevent conflicts with the marine environment. Cutting is the preferred retrieval method, but explosives can be used if the impact on the surrounding environment is the same. If the wellhead is placed at deep water, it may be sufficient to cover the wellhead instead of full retrieval [4].

Formation used as external WBE

In the previous section, the use of creeping formation as external WBE were mentioned. Cases where the external WBE (e.g. casing cement) is lacking sufficient bonding properties, are often associated with following costly and time-consuming operations, like section milling of the casing. By using the formation as barrier, these operations can be avoided. Fig.8 illustrates a creeping formation [15]. The concept of using formation as barrier was introduced at the Oseberg field in 2006. Statoil observed good bonding records from the cement logs, meaning that the formation around the outer casing had been creeping into the casing and established an efficient sealing barrier [14].

The ability to create this sealing barrier is often associated with shale formations. As the shale formation fulfills the NORSOK requirements regarding well barrier properties, the method was accepted by Norwegian authorities and guidelines were introduced to the D-010 standard. The acceptance criteria for using formation as barrier is listed in APPENDIX A in this thesis.

NORSOK states that the formation *shall* be verified by logging and the contact length *shall* be minimum 50 m MD. Verification of well integrity *shall* be conducted by applying a pressure differential across the interval. The integrity at the base of the interval *shall* also be verified by a leak-off test. If the integrity is verified for one well, only logging is required for the subsequent wells (unless the logging results are inconclusive) [4].

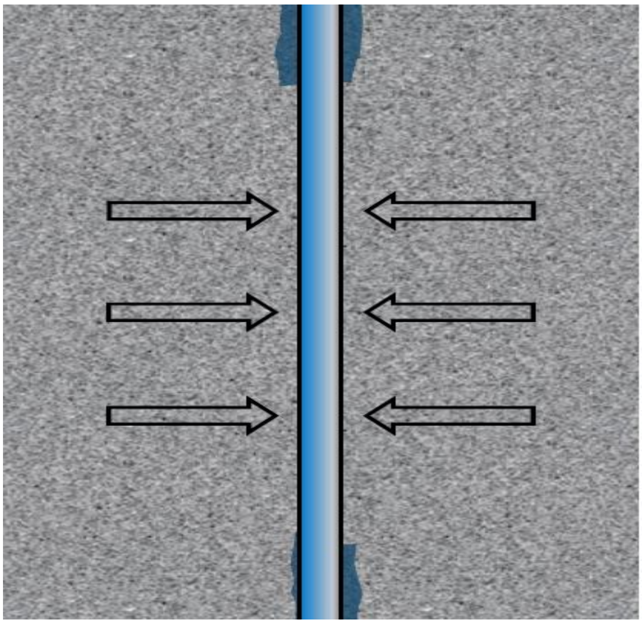


Figure: 8 Illustration of how Creeping Shale Bonds to Casing [15]

2.3 Phases of well abandonment

The Oil and Gas UK Guideline on Well Abandonment, categorizes the well abandonment into three phases which aims to emphasis the scope of work, equipment required and phases timing [16].

Phase 1 – Reservoir Abandonment

The first phase involves isolation of all reservoir producing or injecting zone by placing primary and secondary barriers in the wellbore [16].

Common well activities during Phase 1 [16]:

- Kill the well – usually by bull heading heavy fluid down tubing and circulating up annulus.
- Retrieve production tubing and casings.
- Set primary and secondary plugs to act as barriers against the reservoir.

Phase 2 – Intermediate Abandonment

The second phase involves setting barriers to intermediate hydrocarbon or water bearing permeable zones. This phase lasts until every operation related to plugging is completed [16].

Common well activities during Phase 2 [16]:

- Retrieving casings to fulfill the cross-sectional cement plug requirements.
- Set barrier plugs; either to seal off intermediate reservoir and water bearing zones, or to act as an environmental plug.

Phase 3 – Wellhead and Conductor Removal

The third phase involves removal of wellhead, conductor and casings. According to NORSOK D-010, these shall be cut and removed a few meters below the seabed [4]. The third phase is finished when no further operations is needed on the well [16].

By combining these phases with the associated complexity, it provides a better overview of the required operations on the different wells, for instance when an entire field is to be P&A'd. The complexity of the operation can be classified through a digit (0 to 4) which the Oil and Gas UK Guideline describes in the following way [16]:

Type 0: **No work required** – The given phase is already completed.

Type 1: **Simple Rig-less Abandonment** – Operations can be conducted using Wire Line (WL), pumping and crane. For subsea, Light Well Intervention Vessels (LWIV) can be used.

Type 2: **Complex Rig-less Abandonment** – Operations can be conducted using coiled tubing, WL, pumping, crane, jacks. For subsea, Heavy Duty Well Intervention Vessels (HDWIV) must be used.

Type 3: **Simple Rig-based Abandonment** – Removal of casing strings and tubing is needed.

Type 4: **Complex Rig-based Abandonment** – This type is related to more complex operations, like milling of casing, cement repairs due to poor cement bonding etc.

For defining the complexity of each well, Oil and Gas UK Guideline has provided criteria tables that list certain well characteristics and associated abandonment complexity. Table 3 is used for classifying the complexity of wells during *Phase 1*, the reservoir abandonment. Similar tables can be used for the other phases as well.

Table 3: Method for Classifying the Complexity of Wells during Phase [16]

x:Not Feasible ✓:Required O:Optional

Note #	Well Characteristics / Condition at abandonment	Well Abandonment Complexity: Type 1 Simple Rig-less	Type 2 Complex Rig-less	Type 3 Simple Rig	Type 4 Complex Rig
1	Sustained Casing Pressure due to hydrocarbons or overpressures	X	X	X	✓
2	Not cemented casing or liner at barrier depths (cap rock)	X	X	X	✓
3	Restricted access to tubing	X	X	✓	O
4	Deep electrical or hydraulic lines present at barrier depth	X	X	✓	O
5	Annulus Safety Valve (ASV) present	X	X	✓	O
6	Packer set above cap rock	X	X	✓	O
7	Site does not allow for CT/HWU pumping operations	X	X	✓	O
8	Multiple reservoirs to be isolated	X	✓	O	O
9	Tubing has leak (e.g. corrosion, accessories)	X	✓	O	O
10	Inclination >60 deg above packer (wireline access)	X	✓	O	O
11	Well with good integrity, no limitations	✓	O	O	O

The phases required for a certain well, with the associated complexity, can be listed in a table for further investigation and assessments. This approach is also obtained from the Oil & Gas UK Guidelines [16]. Presenting the concerned wells in this table yields better information regarding the required intervention work, the current well status, operations already completed and so on. This can then be reflected through a P&A code that summarizes the table. Table 4 shows the required methodology for a single well, where the reservoir has already been plugged, the tubing and casing must be retrieved, shallow barrier must be placed, and conductor removed. This yields the P&A code PL 0/3/3.

Table 4: Fictional Example of how the Complexity and Required Work of a Single Well can be Summarized [16].

Platform Well XX_XX			Abandonment Complexity: Type 0 No work	Type 1 Simple Rigless	Type 2 Complex Rigless	Type 3 Simple Rigbased	Type 4 Complex Rig-based
Phase	1	Res. Abn.	X				
	2	Intermed. abn.				X	
	3	WH Cond rem				X	

The table can be used to also include several wells, for instance when a multi-well P&A campaign is to be evaluated. This yields a summary of the number of wells needing a specific method of abandonment for the three phases. Table 5 shows a platform with 10 wells. The reservoir has been sealed on two of the wells, including one well that is plugged completely. The conductors and wellheads must be retrieved for all wells with the use of a rig.

Table 5: Fictional Example of how the Complexity and Required Work for 10 Wells can be Summarized [16].

Field X_Y P&A Campaign, 10 wells			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**	**2**			**8**	
	2	**Intermed. abn.**	**1**			**9**	
	3	**WH Cond rem**				**10**	

2.5 Challenges of P&A operations

When planning for a P&A campaign, it is important to assess the different challenges associated with the project. For a P&A project, there are several factors that will affect the number of challenges. This is related to the type of vessel used, technology required, location of the field and could potentially lead to time consuming and costly operations. In this section, some usual challenges associated with a P&A project in the North Sea will be discussed.

Weather

Waiting on Weather (WOW) is one of the more common environmental disruptions impairing offshore well operations and tasks related to logistics [17]. The weather conditions in the North Sea can be harsh and cause several hours of non-productive time. The severity of this element can depend on season and is usually more critical in winter times. One weather analysis showed that WOW is more crucial in Q1 and Q4, compared to Q2 and Q3 [10]. The impact on offshore operations will also depend on the vessel used. The weather analysis regarding seasons, also showed that the WOW was a bigger problem for Riser-less Light Well Intervention (RLWI) vessels than for semi-submersible rigs [10]. In the same way, a fixed installation may handle the weather better than floating rigs.

Section Milling

To fulfill NORSOK D-010´s requirements, the barrier plug must seal the entire cross section of the well [4]. Hence, if the cement plug is to be placed inside the casing, the annuli behind the casing must be fully cemented. In cases where the cement job is poorly performed, i.e. when the cement behind the casing is lacking the required bonding properties, section milling is the conventical way of resolving this.

Section milling involves grinding off a section of the casing, and eventually the cement behind the casing, using a milling tool (see Fig. 9 below). This enables the possibility to place a cement plug that seals across the entire wellbore. The cement plug could be set either in direct contact with the formation or inside the outer, non-milled, casing. If the plug is placed inside the outer casing, the cement/formation bonding behind must be verified [4].

Milling operations tend to be complicated and may cause several problems. The main problems are related to the generated swarf. Swarf is the small metal particles generated when milling off the casing. The issues are often related to swarf handling on deck and damages on the ram and annular seal inside the blow-out preventer (BOP). Another issue with the milling operations is related to vibrations and knife wear. As the milling causes a great amount of vibration, the cutting knives tend to wear out quickly. This may lead to several trips in and out of hole to replace the worn knives [18].

Logging Through Multiple Casings

Section milling is, as mentioned above, often necessary due to poor cement bonding behind the outer casing string. To determine the bonding situation, logging is normally performed. Logging is then performed in the casing exposed to the cement or formation. However, logging through multiple casing strings is, with current technology, not possible. A solution to this will be to cut and retrieve the inner casing string, so that the logging can be performed inside the outer casing string.

If verification of outer casing cement can be verified without removal of casing or tubing, other methods can be applied for placing the well barrier plugs. One method, squeezing cement through perforation in the tubular, will be explained in the next section. Thus, a technology providing the ability to log through multiple casings could be a huge time saver. Statoil, now Equinor Energy, is working on developing a method for logging through two casings [18].

2.6 Plugging Technology

Well abandonment involves several operations and sub-operations that will require certain methodology and technology. The required technology depends on the complexity of the operation, and will vary from one well to another. In this section, some of the more complex plugging operations and technology will be described.

2.6.1 Section Milling

The section milling method described in Section 2.5 can also be applied to operations that requires milling of multiple casing strings. Weatherford is offering a tool, Endura Dual-String Section Mill, which mills both the inner and the outer casing string [19]. Milling both casings in one run can contribute in reducing the overall P&A duration. The process of section milling is illustrated in Fig.9, where the 9 5/8" casing already has been milled and the milling of the outer 13 3/8" casing has commenced. The last picture in Fig.9 shows the rock-to-rock cement barrier plug placed inside the milled window.

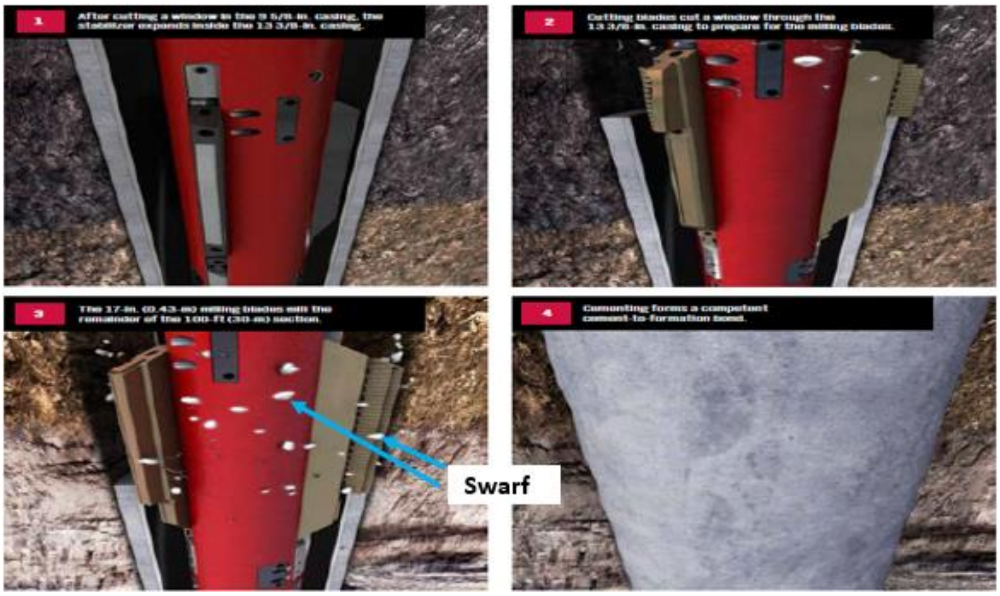


Figure 9: Process of Dual Section Milling by Weatherford [19]

2.6.2 Perforate, Wash and Cement (PWC)

An alternative method to mill and cement is to use the Perforate, Wash and Cement (PWC) technology. The method involves perforating the casing, washing the annulus and then squeeze cement through the perforations to create a cross sectional barrier [20]. This method may be a major time saver, mostly because of the avoidance of milling. New PWC technology also enables the opportunity to perforate and plug across multiple annuli, which before only could be accomplished through section milling (see Fig.10).

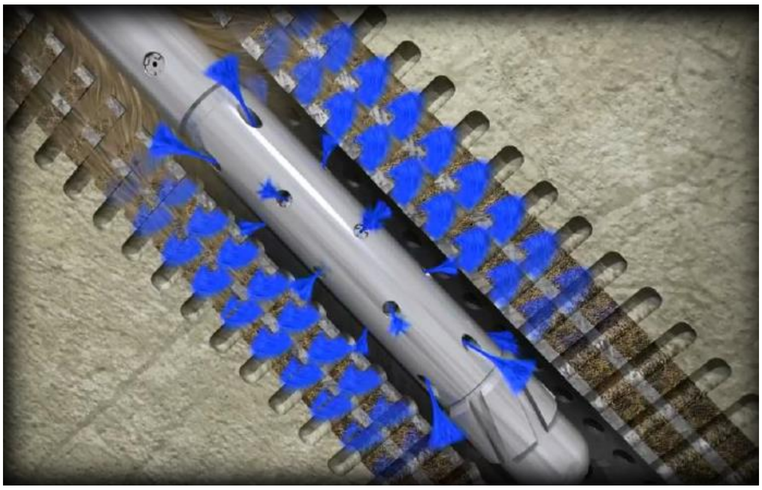


Figure 10: HydraHemera PWC Technology [20]

2.6.3 Conductor and Casing Strings Recovery Using Abrasive Cutters

As mentioned in Section 2.3, the third phase in well abandonment involves removal of wellhead, conductor and casings. According to NORSOK D-010, these shall be cut and removed a few meters below the seabed [4]. There are several ways to approach this removal operation, depending on the given well scenario. This could be related to the condition of conductor and casings, lifting capacity, available technology and so on. If the casing strings are in poor condition, e.g. due to wear and corrosion, it might be beneficial to cut and pull these first, before retrieving the conductor. However, if applicable, the operators could potentially save time by cutting through both the internal casings and the conductor, before pulling everything at once [21].

Modern technology gives the opportunity to cut through multiple strings using abrasive cutters. The *SABRE* cutting system from *Claxton*, can cut all casings regardless of loading, eccentricity and annuli contents. They use a jet of naturally occurring cutting components that in addition to perform cut through multiple casings, have a low environmental impact. This cutting system can be entered through wells with an inside diameter down to 6 5/8”, which eliminates the need for retrieving any internal strings before conductor removal [21].

Figure 11: Conductor and Internal Casings cut with Sabre by Claxton [21]

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3 Probabilistic Time Estimation

Together with the technical preparations conducted before abandoning a well, time and cost estimates are two essential elements when the Authorization for Expenditure (AFE) is up for approval [7]. Accurate and reliable cost and time estimates are also important for the asset retirement obligations. In addition, by using more comprehensive models, sensitivity analysis could be conducted to reveal the most uncertain activities for better planning and allocation of resources. Traditionally, the time estimates are based on historical data through a deterministic approach. This method does only reflect the risks associated with the project by providing possible duration outcome through the 10th and 90th percentile, together with the most likely duration [7].

Since the total duration for well abandonment involves essential uncertainty and risk factors, an estimation model taking these factor into account should be developed. When several wells are to be abandoned, the effect of learning should also be included to the model. These learning effects can reflect both the improvements from a contractor's perspective, as well as the operator's improvements in terms of planning and execution of a well activity.

One approach for a clear and transparent assessment of uncertainties and learning, is to develop a probabilistic estimation model [7]. In this chapter, both the deterministic and probabilistic approach to time estimation will be described, together with the associated advantages and disadvantages. This thesis aims to create a probabilistic time estimate and thus, the probabilistic approach will be given most attention. In addition, the method for including learning curves and unexpected events will be presented.

3.1 Probabilistic and Deterministic Approach to Duration Estimation

Deterministic Estimating

The deterministic approach is appreciated for its simplicity, clear assumptions and the more easily communicated results. The estimation method considers a base-case duration or cost, which may be based on historical data or expert opinions. To express uncertainties, high and low values of this base-case value is calculated. These values are found by adding or subtracting a certain percentage to the base-case value [22]. Traditionally, the deterministic approach has been utilized in the drilling industry. However, the approach has some limitations regarding visibility of the different outcomes. This relates to both describing the entire range of outcomes, and the ability to present the probability of the different outcomes [22]. Experience has shown that deterministic time estimates tend to be overoptimistic from the engineer`s point of view [7].

The report "Analyse av Investeringsutvikling på Kontinentalsokkelen" from 1999, investigated the causes of increased investment costs compared to the originally budgeted on the Norwegian Continental Shelf. The report stated that out of the 12 evaluated projects, 11 projects had an increase in investment costs, ranging from 5 to 35%. Errors in the estimates were assumed to account for 48% of these investment costs. A big part of these errors was related to deviations in the drilling costs [23]. This example emphasizes the importance of establishing estimation methods that better assess uncertainty and risk.

Probabilistic Estimation

Due to its many benefits, probabilistic time estimation has quickly become the preferred method in the drilling industry. Probabilistic approach enables implementation of uncertainty and risk, leading to estimates covering a greater span of possible outcomes [24]. In addition, by incorporating learning curves and unexpected events to the estimation model, one may achieve more accurate estimates. W.M. Akins et.al [24] presents some of the benefits with the probabilistic approach:

- *Acknowledge the uncertainties inherent in well construction and more effectively communicates the range of expected outcomes to stakeholders.*
- *Greatly improves the awareness of risks and opportunities and their potential impact on performance…*
- *…risk and opportunities are identified earlier in the planning process allowing more time to mitigate the risks and take advantage of the opportunities.*
- *Allows for sensitivity analysis that can show where the allocation of resources have the biggest impact on well construction performance [24, p. 2].*

The principle of a probabilistic estimation model is to divide the abandonment project into several sub-operations for which the duration can be given through probability distributions [24]. A fictional example of such a break-down of operations can be seen in Fig.12. The probability distributions are expressing the variation in duration, which consequently assesses the uncertainty in each sub-operation in a better way compared to the deterministic approach [24]. The total abandonment duration will then be the sum of the duration for each sub-operation and can be expressed in the following way [7]:

$$D_{total} = D_1 + D_2 + \ldots + D_n \tag{3.1}$$

Where D_{total} represent the total duration for abandonment of a certain well, D_n expresses the duration of sub-operation *n*, and *n* is the number of sub-operations [7]. The D_1 value in Fig.12 is the value listed in the column "Probabilistic Duration" of the operation "Skid Rig." Expression 3.1 assumes that there is no overlap in operations, i.e. activities are not performed simultaneously.

Procedure 8				
Operations	**Minimum** (days)	**Most Likely** (days)	**Maximum** (days)	**Probabilistic Duration** (days)
Skid Rig	0.04	0.17	0.33	0.13
Intervention	2.50	4.13	5.63	4.81
Remove XT (offline)	0.04	0.13	0.50	0.21
N/U BOP/Riser & P-test	0.50	0.71	1.17	0.75
Pump open shallow plug	0.05	0.13	0.17	0.08
Pull Upp Compl to cut	0.63	1.50	2.63	2.21
Set shallow mech plug	0.04	0.09	0.44	0.15
N/D BOP	0.13	0.38	0.96	0.51
N/D Tubing Head	0.04	0.17	0.38	0.21
N/U BOP/Riser & P-test	0.17	0.42	1.17	1.11
Retrieve shallow mech plug	0.04	0.09	0.44	0.08
Cut and pull tie-back casing	1.88	2.71	3.42	2.75
Log 13 3/8" casing	0.33	0.67	1.38	0.85
Set 13 3/8" casing plug	0.38	0.75	1.33	0.48
Set cement plug	0.50	1.04	2.38	1.51
Tag Plug	0.63	0.88	2.50	1.2
Cut and retrieve 13 3/8" shallow	0.83	1.13	1.42	0.95
Set Plug As base in 18 5/8"	0.25	0.50	0.83	0.7
Set Environmental plug	0.33	0.63	1.25	1.15
Tag plug	0.42	0.58	0.75	0.61
Conductor & casing Removal	2.00	4.00	8.00	4.62
Total Duration (days)				**17.99**

Figure 12: Break-Down of Well Operations with Minimum, Most Likely and Maximum Durations for Each Operation.

The process for establishing a probabilistic time estimation model for well abandonment, could roughly be described in the following way [24] [25]:

1. Define the required operational steps for well abandonment on the given well
2. Express the uncertainties related to the different sub-operations by assigning probability distributions to each sub-operation.
3. Perform Monte Carlo simulation
4. Evaluate the results
5. Adjust the model and re-perform estimation if needed.

As listed above, the methodology for developing probabilistic duration estimates involves the use of Monte Carlo Simulation. Thus, Monte Carlo Simulation, also known as Monte Carlo Experiments, will be explained in the following section.

3.2 Monte Carlo Experiments

Monte Carlo experiments are today used for many different purposes. Problem solving related to physics and medicine, stock price forecasting, cost and duration estimation are all examples where the method is being used [26]. The method can be defined as *"the use of statistical sampling experiments to provide approximate solutions to complex mathematical problems"* [25, p. 217]. Monte Carlo simulations are very applicable in drilling cost and time estimation due to the great amount of uncertainties related to the drilling operations.

In this section, the different steps of the Monte Carlo process will be presented along with some basic theory regarding probability distributions. Although the method could be implemented with no more than basic statistical knowledge, there are some pitfalls that the user should be aware of. These pitfalls will also be described further in this section.

3.2.1 The Steps of a Monte Carlo Simulation

Although there are many ways the simulation can be conducted, the method is usually based on input data, for instance historical duration data, along with their associated uncertainty. The simulation software then samples the input data and provides possible values. This process is referred to as a *trial*. The number of trials performed varies, but is often set to several thousand for more accurate estimates. H.S Williamson et.al [25] and W.M Akins et.al [24] both describes the method for conducting Monte Carlo simulations. The remaining part of this section will mainly be based on these. The development of a Monte Carlo simulation can be conducted in the following way [25]:

1) Describe the Model
2) Data Collection
3) Determine the Input Data Distributions
4) Run the Simulation
5) Interpretation of the Results

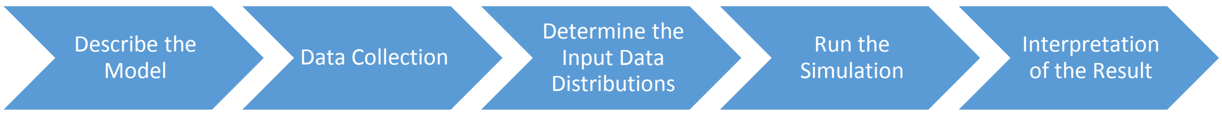

Figure 13: Monte Carlo Simulation Process [25]

Important to note is that the first three steps of the Monte Carlo experiment, illustrated in Fig.13, can be combined with the first two steps of the probabilistic model development described in Section 3.1. These steps are concerning the same, and thereby no need for describing the model, make an operational plan, and collect data twice.

Describe the model

The first step of the Monte Carlo Experiment is to define the model in terms of scope and objective. What do we want to simulate? What should be included in the model, and what parameters are not of interest? Based on the purpose of the estimation, also the level of detail must be considered. The level of detail relates to the number of sub-operations considered, and is normally increasing as the execution of the project approaches [24]. The inclusion of risk and uncertainties should also be evaluated. This will be discussed further in Section 3.3.

Data Collection

Collecting the input data that form as the base of the simulation, is often the most difficult part of the simulation process. The duration data are normally obtained from historical duration for similar activities conducted and/or expert opinions. It is important to collect a large data set to cover a great span of probable outcome. However, as the off-set data should be comparable to the considered project, this process could be both difficult and time-consuming. If there is a lack of good off-set data, expert opinions should also be considered. The experience and knowledge that different experts possess may vary and hence, involving several experts may result in more thorough assessment [24]. It is worthwhile to devote time in collecting data. More accurate input data will result in more accurate estimates [17].

It is also important to be consistent when it comes to exclusion of particularly poor outcome. The poor outcomes should be evaluated to assess if the outcome should be a part of the final data, and eventually if it should be incorporated to the model as an undesirable event. By choosing to exclude the poor outcome, based on the beliefs of a one-time occurrence, valuable information regarding uncertainties could potentially be lost [25]. Data collection will be described further in Chapter 6.

Determining the input data probability distribution

To reflect the great span of outcomes, one must select a probability distribution for the duration of the different sub-operations. Even though there are several distributions, the industry often turns to either a uniform or triangular distribution when developing estimation models [24]. The triangular distribution, which will be used in this thesis, is based on a minimum, most likely and a maximum value. According to H.S Williamson et.al [25], the choice of distribution for duration modelling is not crucial. He states the following:

The central limit theorem tells us that our distribution will have a mean close to the sum of the means of the individual distributions, a variance close to the sum of the variances of the individual distributions (provided we sample the distributions independently), and shape that approximates the normal (i.e.., bell-shaped) distribution [25, p. 220].

This means that the only dependent factors regarding the probability distribution for the sum of a substantial number of variables, is their *standard deviation* and the *mean*, and not the *distribution shape* of the individual variables [*25*].

Run Simulation

To run the simulation, a computer software is needed. For this thesis, the add-in software *@Risk* is used in combination with *Microsoft Excel*. *@Risk* predicts a value for duration on a sub-operation, based on the underlying data and the associated probability distribution. These predictions are then added together to form the total duration. This process is called a trial. By performing thousands of such trials, one will get thousands of different duration predictions, which is summarized in a probability distribution graph. These distributions are then up for interpretation.

Interpretation of the simulation result

As mentioned, the output of the simulation is a set of probability distributions. These distributions must then be checked for errors before it can be further used for decision making, resource allocation, setting of targets and so on. A simple approach to verify the output is to compare the results against expectations [25]. Before presenting the interpretation further, it will be worthwhile to first describe some common technical terms from statistics.

- ***Mean Value****:* The average of all output provided by the simulation.
- ***Mode****:* The most frequently appeared value through the thousand iterations performed.
- ***Percentiles:*** The probability that a random draw from the data set will be within a certain range, is described through the percentiles. When the data is ordered increasingly, the P_{th} percentile is the value that P% of the possible outcomes are less than. This implies that (1-P) % of the possible outcome will be greater than the P_{th} value. P10 is the value below which 10% of the outcomes fall, P80 is the value below 80% of the outcome fall and so on [24].

Fig.14 shows the probability distribution through a Probability Density Function (PDF), which is one of the output provided by the Monte Carlo simulation. As explained, the P50 value is the value below, and above, that 50 % of the outcomes will fall. That is, the point where the area underneath the graph shown in Fig.14, will be divided in half [24]. The *mode* is given through the highest point on the PDF curve, while the *mean* is represented through the line to the right of the P50 line.

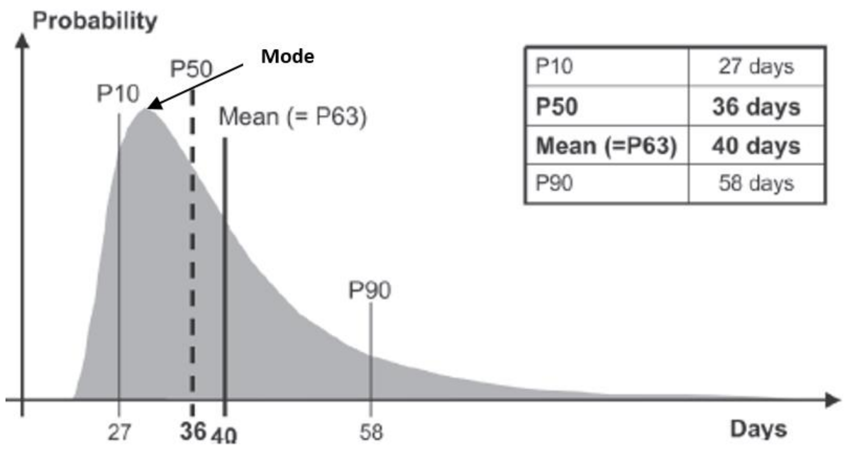

Figure 14: A Probability Density Function [25]

As previous mentioned, one of the benefits of conducting probabilistic estimation, is the ability of conducting sensitivity analysis. These analyses can give information regarding the most time consuming sub-operations, the sub-operation involving the greatest uncertainty and thus, where the resources should be allocated in the planning phase. The @Risk software provides, in addition to the probability distribution, a tornado chart reflecting the sensitivity of the different operation. An example of such a chart is shown in Fig.15. The uncertainty could then be evaluated with ease, as the chart rank the operations having greatest impact on the output mean. We see that the operation regarding the logging of 9 5/8" casing is causing the mean of total duration to vary between 34.2 and 42.6 days. Presenting the most uncertain activities through a tornado chart will yield a more intuitive interpretation compared to only presenting numbers.

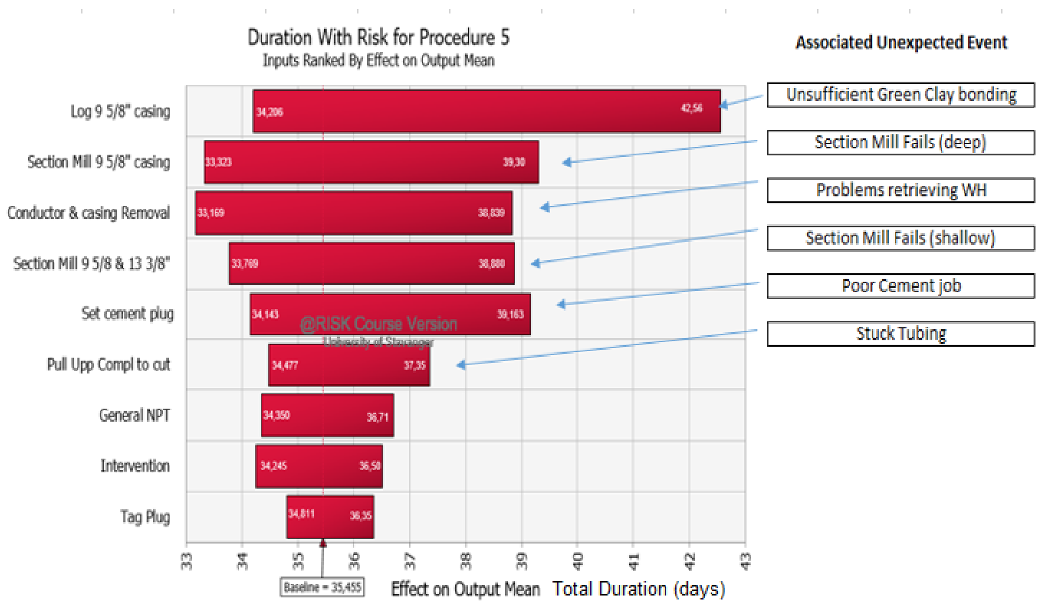

Figure 15: Fictional Example of a Tornado Chart Ranking the Most Critical Well Operations.

3.2.3 Pitfalls using Monte Carlo

Even though the different steps of a Monte Carlo simulation are straightforward to perform, there are some pitfalls that one should be aware of. By avoiding evaluating these pitfalls, the presumed benefits of a probabilistic model could potentially vanish. Hence, in this section the thesis will present some of the pitfalls associated with Monte Carlo simulation. The pitfalls are presented in the article *"Monte Carlo Techniques Applied to Well Forecasting: Some Pitfalls"* [25]. The examples presented in the following are conducted using @Risk in Excel and are based on the article introduced above.

Pitfall Number One – Selecting Minimum and Maximum Input Values for Triangular Distribution

To address the uncertainty of a sub-operation, the duration is reflected through a probability distribution - often set to a triangular distribution. Furthermore, we need to select a minimum, maximum and a most likely value based on the data set collected. The way of defining the maximum and minimum value is often misunderstood [25] and the problem could be visualized through the following example.

If we consider the data set in Table 6, reflecting the duration for a certain sub-operation. Which values should be used as input in the triangular distribution? If the values 18 and 35 hours are selected to represent the maximum and minimum value, do we cover all duration values the outcome can take? If those values are selected, we are assuming that through these 17 operation examples, we have experienced both the fastest and the slowest time that the certain operation could take. This may not be the case and could potentially lead to systematic underestimation [25]. For smaller data sets, this pitfall will be more important to evaluate.

Table 6: A Fictional Data set containing 17 observations for a certain well operation.

Observation #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Duration (hrs)	18	20	24	28	30	35	19	25	31	28	24	26	18	20	21	24	34

The earthquake off the Pacific coast of Tohoku, Japan, on March 11, 2011, is a good example of how underestimation can result in a disaster. The earthquake generated a tsunami which inundated a 2000 km stretch of the Pacific coast of Japan causing over 15 000 fatalities.

Although the height of the protection walls set up across the coast were based on historical incidents, they were not able to withstand the waves that struck the coast in 2011. Later reports have shown that the potential wave height was underestimated leading to undersized protection walls not covering a worst-case scenario [27].

Pitfall Number Two:

Pitfall number two is also related to the selection of values to be used in triangular distribution. By presenting the *most likely* value as the mean or median of the data set, errors causing both underestimation and overestimation is likely [25]. Suppose the same data in Table 6 as reference. The mean and standard deviation of the data set is 25 and 5.38 hours respectively. Suppose we use the mean value of the data set to reflect the *most likely value* in the triangular distribution. In addition, we use the maximum and minimum values defined in pitfall number one. This will yield a distribution with a mean that is indifferent from 25 hours and a standard deviation indifferent from 5.38 hours.

Fig.16 illustrates the case and from the yellow mark we see that the mean is estimated to 26 hours while the standard deviation is 3.48 hours. The predicted minimum and maximum values are 18 and 35 hours respectively. Consequently, the estimates tend to be too optimistic or too pessimistic if the input data is skewed respectively to the right or left [25].

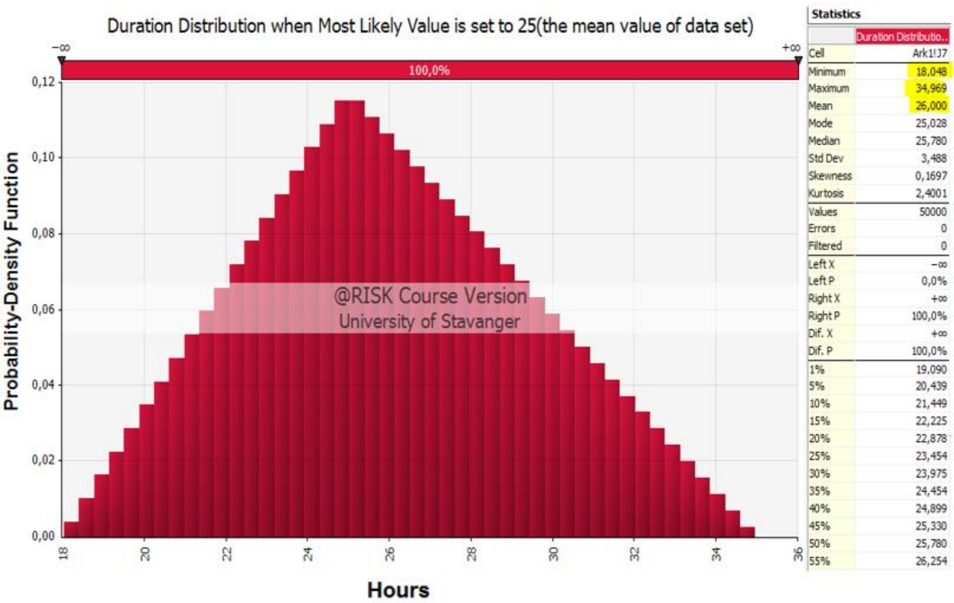

Figure 16: Probability Distribution for Illustrating Pitfall Number 1 and 2.

Solution to Pitfalls Number One and Two:

The solution to the first two pitfalls is to calculate the maximum, minimum and most likely value, in such a way that the resulting distribution will have the same mean and standard deviation as the data set. H.S Williamson et.al propose the following steps for calculating the distribution inputs [25].

The minimum, most likely and maximum values are calculated based on the mean and standard deviation of the considered data set. Thereof, for a data set, x_i, consisting of n values, we will express the mean and standard deviation as

$$Mean = \frac{1}{n}\sum_i x_i \tag{3.2}$$

$$SD = \sqrt{\frac{n\sum_i x_i^2 - (\sum_i x_i)^2}{n(n-1)}} \tag{3.3}$$

We then select a minimum value that fulfill the following constraint

$$mean - 2\sqrt{2}SD \ \leq minimum \ \leq mean - \sqrt{2}SD \tag{3.4}$$

From this we get

$$Most\ Likely = \frac{3mean - minimum}{2} - \sqrt{6SD^2 - \frac{3}{4}(mean - minimum)^2} \tag{3.5}$$

And;

$$Maximum = \frac{3mean - minimum}{2} + \sqrt{6SD^2 - \frac{3}{4}(mean - minimum)^2} \tag{3.6}$$

By inserting the data from Table 6 to expression 3.2 and 3.3, we obtain a *mean* of 25 and a *standard deviation* of 5.38. By inserting these numbers into expression 3.4, we obtain the upper and lower boundary from which we can choose the *minimum* value. The average of the two boundaries could for instance be used as minimum value. The minimum value could also be selected based on expert opinions. The *minimum* value is selected and inserted in expression 3.5 and 3.6 to obtain *most likely* and *maximum* values.

We achieve the minimum, most likely and maximum value of respectively 14, 22 and 39 hours. The resulting distribution will now reflect a range of possible outcome that exceeds the minimum and maximum of the data set. In addition, we obtain a distribution having the same mean and similar standard deviation as for the data set. This is illustrated by the yellow marks in Fig.17.

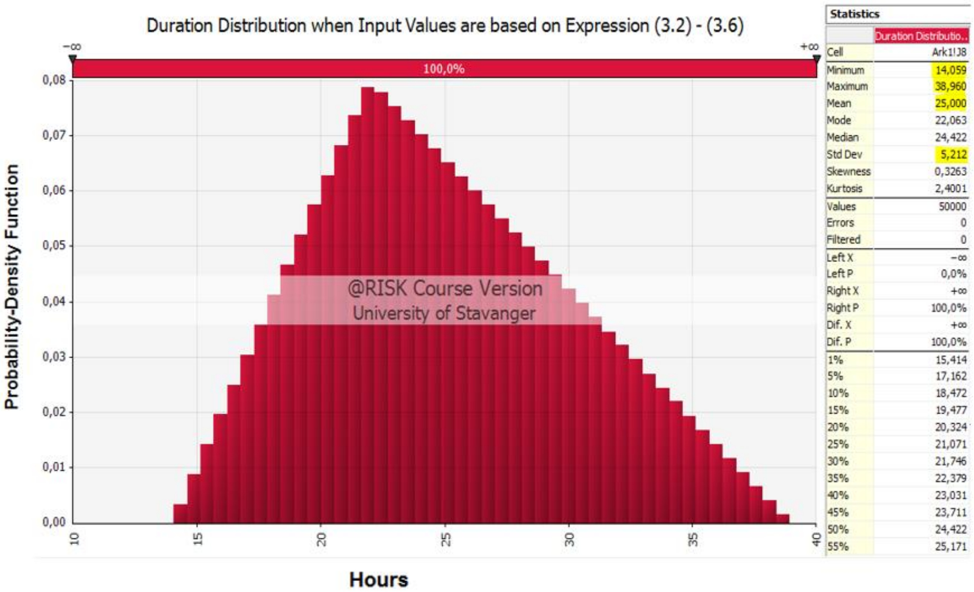

Figure 17: Probaility Distribution for Illustrating the Solution to Pitfall Number 1 and 2.

Pitfall number three: Adding up the P 50 value to form the total duration

When conducting time estimation for several wells, e.g. when a multi-well campaign is considered, we can typically add single-well duration estimates to obtain the total duration. However, should we add the mean values for each well, or should we use the median values? A common mistake in multi-well forecasting is to not consider the resulting difference in using either of the two values [25]. The truth is that the selection of values to be added can have a significant impact on the total duration estimate. This will be explained through the following example.

If we conduct a Monte Carlo simulation for abandonment duration for a single fictional well, we obtain the probability distribution shown in Fig.18. We see that the P50 value (the median) is 26.3 days, while the mean is 26.9 days. If we consider 15 wells, identical to the one presented in Fig.18, and present the total duration for abandonment of all wells by multiplying the P50 value with 15, we obtain a total of 394.5 days.

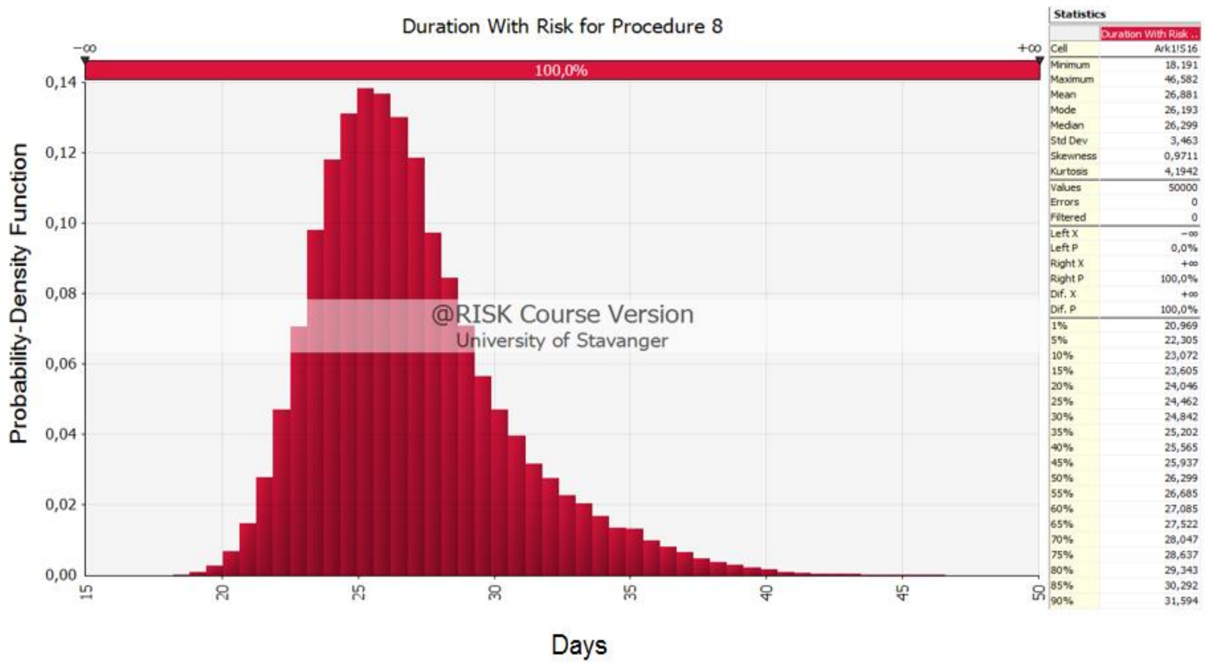

Figure 18: Probability Distribution for a Single Well Provided to illustrate Pitfall Number 3.

If we make a Monte Carlo simulation that predicts the duration for abandonment of these 15 wells, we obtain the probability distribution presented in Fig.19 below. We see that based on this probability distribution, there is only 25% chance of abandoning these 15 wells in less than 394.5 days. The P50 value is 403.2 days, which is different from the value obtained by adding the P50 value from the single-well forecast. If we instead chose to add up the mean value, i.e. 26.9 days per well, we obtain a total duration of 403.5 days, which is equal to the aggregated P50 value shown in Fig.19.

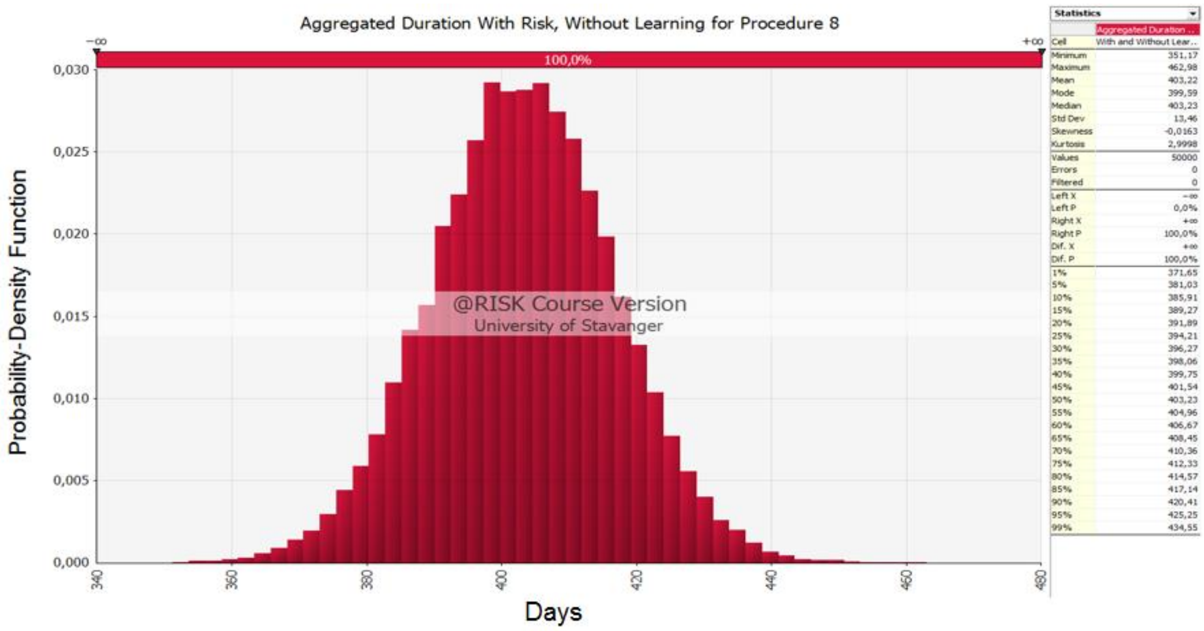

Figure 19: Probability Distribution for the Aggregated Duration of 15 Wells Provided to Illustrate Pitfall Number 3.

In addition to the pitfalls presented above, it is important to take the impact of learning and unexpected event into consideration when developing time estimation models. The next section aims to describe the impact and method for incorporating these elements into the model.

3.3 Inclusion of risk – unexpected and undesirable events

One of the benefits with the probabilistic model is the opportunity to incorporate the effect of different risk and uncertainty factors. The probabilistic model could furthermore provide the company with useful information regarding the likelihood of these events to occur and the sensitivity of the different operations. Thereby, one could obtain better assessment on more risky operation in the early planning phase. Regarding the number of events to take into consideration, it depends on company policy and their previous experiences from similar activity [24]. If an unexpected event has occurred several times during the past, for similarly conducted projects, they are more likely to occur and should therefore be included in the model [25].

Some potential undesirable events related to P&A activities are presented in Table 7 below [17]. It is, however, important to treat each project individually and to evaluate which events that are likely to occur for the considered project. When the final list of possible undesirable events is established, their associated probability and possible duration should be assigned. The probabilities and likely durations are typically based on historical incidents and/or expert opinions.

Table 7: General Unexpected Events for P&A Activities [17]

Unexpected Events	Consequences
Lack of communication between tubing and annulus after punching (Valdal 2013)	Need higher punch, need extra run
Collapsed tubing or casing	Need for specialized equipment and plan to remove collapsed casing, tubing, and obstructions
Problem to cut tubing (Valdal 2013)	Need recut or change tool
Not able to pull tubing	Need to work on tubing-hanger retrieval
When pulling out the tubing, it breaks into a few parts	Need extra runs
Operational problems have been encountered with perforate, wash, and cement (PWC) technology (Ferg et al. 2011).	Drill cement plug inside casing and check quality of cement behind casing. 1. If quality of cement behind casing is good, set a new cement plug inside the casing. 2. If quality of cement behind casing is not good: a. Mill, clean, underream the section, and set a balanced cement plug b. Set a new plug by PWC system in different interval if requirements for setting depth are met
There is not uncemented casing across the setting interval.	Change the program: Mill, clean, underream the section, and set a balanced cement plug.
When using PWC technology, there is not additional wellbore length for guns to be left in the hole (Ferg et al. 2011).	Use two or three trips with PWC system, which require additional time.
Not able to pull casing	Extra cuts in different sections of casing and need additional runs
Problem to cut casing	Need recut or change tool
When pulling out casing, it breaks into a few parts.	Need extra runs
Contamination of cement during placement or failure of cement during test	Need to set a new plug

When evaluating the uncertainties related to well activities, it is important to differentiate between major risk event, general non-productive time (NPT) and waiting on weather (WOW). Although all represents duration that are not productive time, the method for including these into the model may be different [24].

3.3.1 The Method for Incorporating Risk into the Estimation Model

Incorporation of Major Risk Events to the Model:

The major risk events, normally known, can be related to certain operational steps in the abandoning process. The events listed in Table 7, are typical examples. The duration of these unplanned events will be reflected in the same manner as for the planned well operations described in the previous section. I.e., the duration of the unplanned events will be reflected through a probability distribution that is based on historical data and expert opinions. The possible duration of these events could then be assigned to their associated "trouble-free/planned" activity in the model [17]. As an example, the total duration of "Pulling the Tubing" operation will be the predicted "trouble-free" duration, plus the predicted duration of the potential unplanned event, "Stuck Tubing."

Another method for incorporating the major risk events to the model is to add the total predicted duration of the unplanned events to the total "trouble-free" durations for a given well. The latter method will be used in this thesis and will be further explained in Chapter 7.

Incorporation of general NPT to the model:

While the major risk events relate to a specific trouble-free operation, the general NPT can be recorded anytime during the operations [24]. This could for instance be the recorded non-productive time for general rig maintenance. From historical data regarding general NPT on the given rig, we add a certain percentage to the total duration to reflect the contribution of these events. As the percentage of general NPT is uncertain, assigning a probability distribution to reflect the actual NPT percentage will be beneficial for the model. This method will also be discussed further in Chapter 7.

Incorporation of Waiting on Weather (WOW) to the model:

The method for including the WOW factor will be as for the inclusion of general NPT. It is important that the percentage used is evaluated individually and applicable for the given rig or field. This is because the impact of WOW will depend on the season of the year, the rig type used, and the required operations conducted [10].

3.3.2 The Effect of Including Risk on the Simulation Output:

The probability-density function provided by the Monte Carlo simulation is likely to change as we include uncertain events. For outcomes with high predictability, the curve tends to have a symmetrical shape, i.e. the upper and lower values will be of similar magnitude and probability [25]. As we increase the amount of uncertainties and unexpected events, the curve will shift and have wider ends, i.e. the range of possible outcomes will increase [17]. In addition, it is often assumed that by increasing the uncertainty, the curve will be highly skewed. Skewed is the word used to describe a more asymmetric curve. According to H.S Williamson, this is not always the case, and will be illustrated with the following fictional example based on Williamson's article [25].

Consider a well project where several unplanned events are included in the estimation model. The distribution outputs are presented in Fig.20. All events have the same possible duration and the same probability. For the first case, when the probability is set to zero, we see that the probability curve has a symmetric shape. As we increase the probability of each unplanned event, the curve skews to the left. This continues to a certain point, before it alters towards a more symmetric shape as the probability increases even further.

The reason for this can be explained by looking at the right-side tail of the distribution. The tail developed on the second distribution in Fig.20, will contain the wells where the unplanned events occur. By increasing the probability of these events to occur, a greater percentage of the wells will fall within this tail, and thus, the tail will lose its distinct character [25]. However, the curve will shift towards higher durations for the case with high probability. Even though the tail-end vanishes, the curve will still be exposed to a wider shape and greater uncertainty.

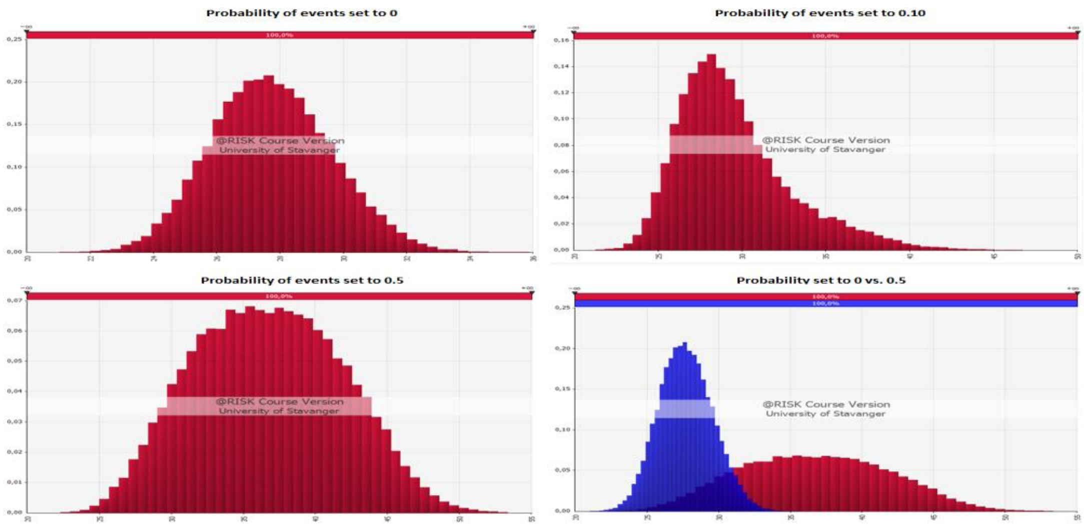

Figure 20: The Effect on the Duration Estimates when Including Risk

3.4 Inclusion of Learning Curves

For multi-well P&A campaigns, operation performance is likely to improve over time [28]. These improvements can be related to the operation efficiency by the contractor, as well as the operator's improvements in terms of planning and execution of a well activities. The rate of this improvement is reflected through a learning curve. By collecting historical data from similar campaigns, one could calculate the parameters that are required for expressing the learning curve. The curve can then be integrated to the estimation model, which may, if integrated properly, yield estimates that are more accurate. Contrary, if the learning curve is not considered, i.e. assuming constant performance, the estimates tend to be overly pessimistic [28].

However, there are certain scenarios where the effect of learning will be of less significance and thus, not appropriate to incorporate into the estimation model. In smaller campaigns, time can be a constraint, leading to less thorough evaluation and maturation of the learning. If the campaign consists of wells with different well-design and degree of complexity, the learning effect may also be reduced [28]. With that in mind, it is important to evaluate each well, for sorting out where the effect of learning is likely to contribute to the performance.

It has become a frequent practice among operators to establish a learning curve to include in the duration estimates. The curves can be established through deterministic or probabilistic estimates, depending on the available amount of data [28]. Available P&A data from similar campaigns reduces the uncertainty and thus, deterministic learning is applicable. In the following, two methods for establishing a learning curve are explained.

3.4.1 A Parsimonious Model:

Chi U. Ikoku presented a model, at the SPE California Regional Meeting in 1978, that expresses the learning curve through the following expression [29]:

$$y_n = an^b, \tag{3.7}$$

where y_n reflects the duration of the n_{th} well in the P&A sequence. *A* and *b* can be estimated through regression of the historical data.

3.4.2 Brett and Millheim Model

The Brett and Millheim model was established to, using learning curve theory, derive drilling performance for a set of wells [30]. Although the model was established to derive drilling performance, it is also applicable for other well activities, e.g. P&A activities. The Brett and Millheim model is well accepted in the drilling industry for its simplicity and the information provided by the explanatory parameters in the model [28]. A model that relate the order of wells drilled and the total drilling time can be expressed in the following way [30]:

$$y_n = C_1 e^{(1-n)C_2} + C_3, \tag{3.8}$$

where y_n is, as in the parsimonious model, the duration of the n_{th} well in the sequence and C_1, C_2 and C_3 is the parameters to be estimated. The parameters to be estimated can be interpreted as:

- ***C₁*** – *"a constant reflecting how much longer the initial well takes to drill than the idealized final well"* [30, p. 3].
- ***C₂*** – ***"****a constant reflecting the speed with which the drilling organization reaches the minimum drilling time for an area"* [30, p. 3].
- ***C₃***– *"constant that reflects the idealized minimum drilling time for an area"* [30, p. 3]. I.e. the technical limit.

The C_3 value will depend on the complexity of the wells, e.g. casing design, inclination of wellbore, technology and so on. Operating at the C_3 value, or technical limit, over time, indicates that the company is not progressing from its experience. However, improvement is still plausible. The C_2 value reflects the rate of which the company learn to improve their performance. Thus, a high C_2 value implies that the company can more quickly approach the upcoming wells, with better performance due to the learning effect from the first wells [30].

Process for estimating the constants – least squared error method

There are several methods for determining the C's. One approach is to use a non-linear minimization method to obtain the constants minimizing the least squared error between the model and the actual data. This can be achieved using statistical program. The following steps can be performed for establishing the estimates [30]:

1) Incorporate the actual duration data to the program, i.e. the P&A duration for the wells in sequence.
2) Make some initial guesses for the value of C_1, C_2 and C_3.
3) Insert the guessed C values into expression 3.8, to establish the estimated duration for each of the considered wells.
4) Calculate the errors squared – the difference between the estimated duration and the actual duration squared.
5) Use the Solver function in Excel to determine the C values yielding the least squared error.

Consider the following example. Duration data for 10 fictional wells are listed in Table 8. These are also represented through the orange line in Fig.21. By making an initial guess of the C parameters, the guessed learning curve (colored in grey) is established. Guesses are conducted in accordance with the suggestions provided by Brett & Millheim. That is, C_3 is set to the duration average of well number nine and ten, C_2 is set to 0.4, and C_1 is found by subtracting C_3 from the duration of the first well [30]. Table 9 presents the initial guess of C values.

Further, the mean squared error between the actual and first guess learning curve are calculated. The Solver function in Excel is then used to determine the C parameters minimizing the calculated mean squared error. These values are also listed in Table 9. The estimated C values are then applied to equation 3.8 to establish the estimated learning curve colored in blue. As illustrated by the green arrows in Fig.21, the curve is shifted towards the actual duration curve, i.e. reducing the mean squared error. The value of C_1, C_2, and C_3 is illustrated on the left side of the graph in Fig.21.

Table 8: The Process of Developing a Learning Curve for Actual Data

Learning Curve	Days			
Well #	Actual Duration	Estimated Learning Curve	Error	Error Squared
1	34	32,44	1,56	2,423
2	24	27,35	-3,35	11,218
3	25	23,60	1,40	1,969
4	20	20,83	-0,83	0,693
5	19	18,80	0,20	0,041
6	20	17,30	2,70	7,308
7	16	16,19	-0,19	0,037
8	15	15,38	-0,38	0,143
9	14	14,78	-0,78	0,606
10	14	14,34	-0,34	0,113
			Mean Squared Error	2,455

Table 9: Initial Guess and Estimated Values for the C-parameters

	Initial Guess	Estimated
C1	24	19,34
C2	0,4	0,31
C3	14	13,10

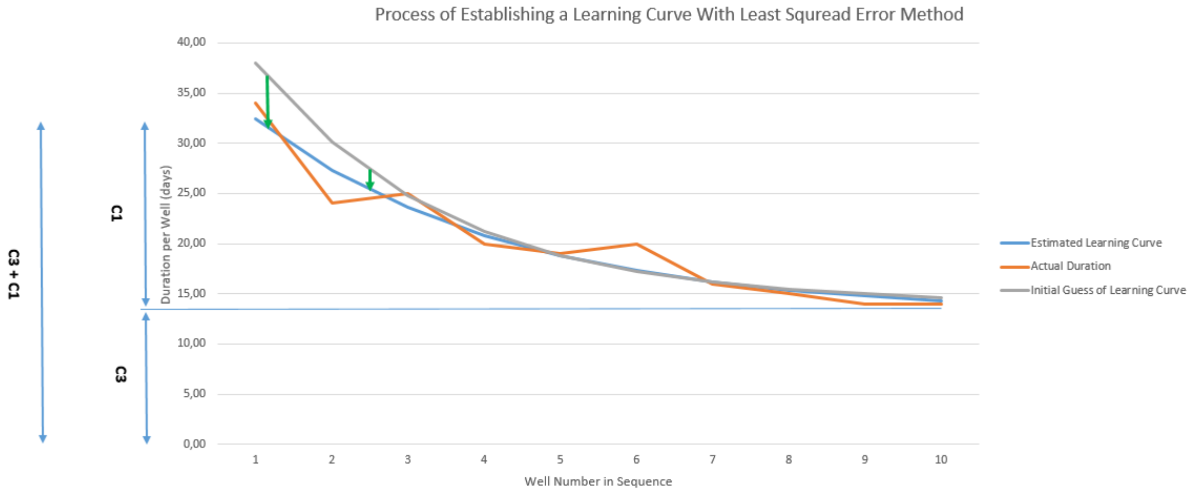

Figure 21: Establishment of Learning Curve in accordance with Brett and Millheim Theory

3.4.3 Method for Integrating the Learning Curve to the Probabilistic Model

Jablonowski et al. propose a 2-step method for incorporating the effect of learning to a multiple well duration forecast [28]. Depending on the certainty of the estimates of C_1, C_2 and C_3, this could be conducted through a deterministic or probabilistic approach. For this thesis, only the deterministic method will be described.

Step 1 – Base Case: Probabilistic Duration Estimation

In the first step we make a probabilistic duration estimate for each well. This is obtained by creating the estimation model described earlier in this chapter. We then add up the concerned number of wells to form an aggregated distribution. This forms as the base case, with no learning [28].

Step 2 – Including Learning

In this step the parameters of the Brett and Millheim expression needs to be defined. If the estimator is certain about the estimates of these values, it could be applied to the model in a deterministic way. The duration for each well could then be calculated through the expression 3.2. By implementing these duration into the base model, we obtain the aggregated distribution including the effect of learning [28]. The method will be described in more detail in the Chapter 7.

4 The Brage Field

The field Brage was first discovered in 1980 by Norsk Hydro, which operated the field until 2009. The first oil produced was recorded in 1993. Statoil operated the field from 2009 until it became Wintershall Norge's first operated production field in 2013. Today, the ownership of the field is allocated Wintershall Norge AS (35.2 %), Repsol Norge AS (33.9 %), Faroe Petroleum (14.3 %), Point Resources (12.2%) and VNG Norge AS (4.4 %). The field is located on Blocks 30/6, 31/4 and 31/7 in the northern part of the North Sea [31].

Figure 22: Location of the Brage Field [31]

The production on Brage involves both oil and gas, and the original oil in place was estimated to be 157.8 mill Sm^3. The initially recoverable oil was estimated to be 62.5 mill Sm^3 whereof 4.25 mill Sm^3 remains to be recovered [9]. Fig.23 denotes that the production on Brage has decreased since the peak in 1996. The production today is approximately 40 000 bbl./day, which is 80 000 bbl./day less than the peak of production in 1996 [9].

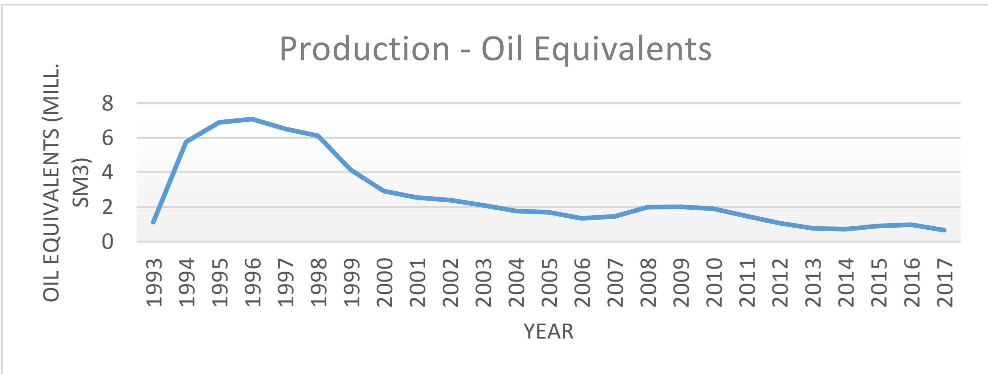

Figure 23: Oil Production on Brage since 1993 [9].

4.1 Well History

The first six wells on Brage were drilled before the platform was installed, using the semi-submersible rig Vildkat Explorer. The first well, A-1, were drilled in 1991. When the fixed platform was installed in 1993, well A-1 to A-6 were tied back to the surface. During the same year, 10 curved and 18 straight conductors were further installed. Six additional wells were spudded three year later. Thus, the total number of slots on Brage is 40 [32]. Several wells on Brage has been plugged back and then re-entered at a later stage. Re-entering and kicking off from the initial well bore gives the opportunity to change the well path and either produce from other part of the reservoir, or target nearby reservoirs.

4.2 The Brage Platform

Brage is an integrated platform with living quarters, process modules, drilling modules, auxiliary modules and manifolds areas. The bed capacity of the platform is 130 people. The platform is located at 137 m water depth with a steel jacket extending down to seabed. As the platform does not hold any storage capacity, the produced oil is sent via the Oseberg Transport System to the Sture Terminal. Regarding the gas production, this is being exported via pipeline to Kårstø [31].

Figure 24: The Brage Platform [31]

4.3 Geology and Reservoirs

The Brage field is located on the Horda Plateau, east of the Viking graben. The producing reservoirs are Statfjord, Fensfjord, Sognefjord and Brent. For Statfjord, Fensfjord and Brent, the main draining strategy is water injection. Sognefjord is produced with depletion and pressure support from the strong aquifer and initial gas cap [9]. Fig.25 presents some of the formation groups and involved formations on Brage.

The formations in Nordland Group, Rogaland Group and Hordaland Group mainly consists of shale with some limestone in the two latter. However, Utsira in Nordland and Oligocene in Hordaland are permeable zones of sandstone. The Draupne Formation in the uppermost part of Viking Group consists of organic rich "hot" shale while the Heather formation consists of silty claystone. The Fensfjord Formation in Viking Group is sandstone. The Dunlin Group and Amundsen Formation consists of claystone, shale and siltstone. Statfjord consists of sandstone [33].

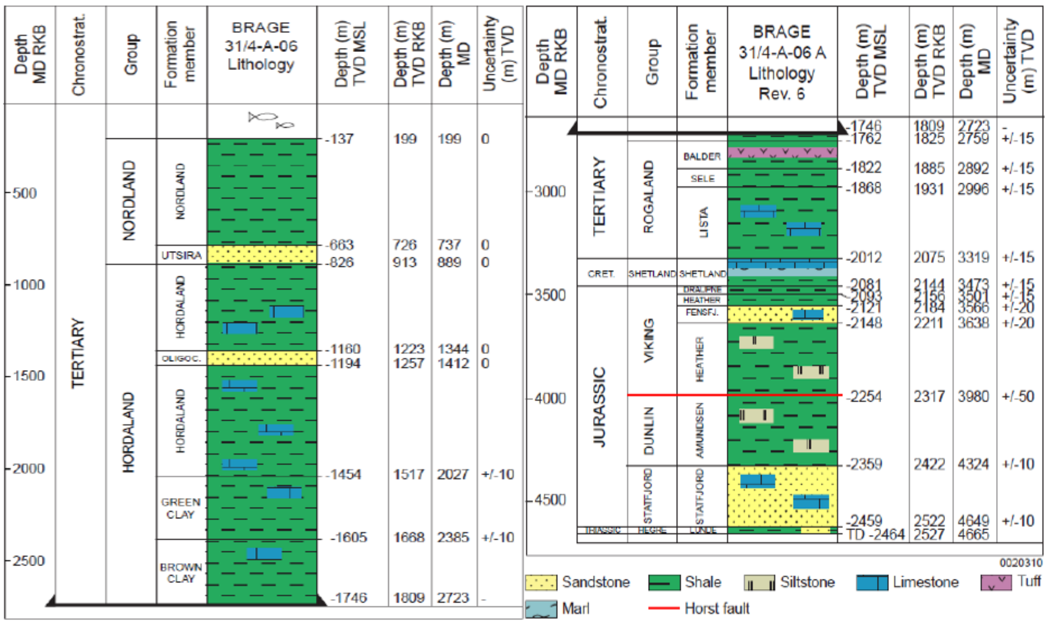

Figure 25: Overview of the Overburden on Brage [33]

The lower part of Hordaland Group consists of the Green Clay and Brown Clay Formations. The Green Clay Formation top is at approximatly 1500 m TVD while the Brown Clay

Formation is normally encountered at 1600 m TVD [33]. Logging condcuted by Wintershall has shown a Green Clay Formation with creeping abilities. This ability were explained in Section 2.2.3.2 regarding creeping formation as external barrier. According to Wintershall, the Brown Clay formation is also likely to create bonding to the casing, and thus, the thickness of potential creeping formation is approximatly 300m [33].

5 Plug and Abandonment on Brage

The proposed solution for P&A on Brage will be in accordance with regulations and guidelines on the NCS. Thus, the theory in Chapter 2 will be applicable. What's also mentioned in Chapter 2, relates to the recent discovery of using formation as an external well barrier. Previously conducted logs by Wintershall, shows that the Green Clay formation on Brage forms good bonding to the casing. Thus, placing the primary and secondary cement plug in this interval can reduce the overall duration of P&A. So, unless stated otherwise, all primary and secondary plugs will be placed within this interval. For simplicity, the depth of placement for these plugs will not be considered in terms of calculations.

To establish operational procedures for P&A on Brage, the 40 wells need to be categorized. Each category will then be assigned a specific procedure which again can be used in the estimation model. This chapter aims to classify the different wells based on their well design and the required P&A operations. First, a rough categorization will be established. For each category, the required type of work and associated complexity will be presented in the table, based on the UK Oil & Gas Guidelines [16]. Second, a more detailed categorization will be presented based on distinct characteristics of the different wells. A flowchart based on the detailed categorization will then be applied for determining the actual procedure. At last, some unplanned events associated with the P&A on Brage will be defined.

The categorization and operational procedures are based on a previously conducted master thesis regarding P&A on Brage [34], "Final Well Reports" from Wintershall's data base [32], and assessments performed with drilling engineers at Wintershall.

5.1 Overview and categorization of all wells

As mentioned initially, Brage consists of 40 wells. Due to the differences in well design, the P&A method required will vary between the different wells. These differences relate to the geology, top of cement (TOC), the depth of casing shoe relative to the Green Clay, the type of well etc. Thus, by categorizing the wells based on their design and plugging complexity, one will achieve a better overview of the required operations for well abandonment.

The wells on Brage can be divided into four main categories: Simplified Casing Design, Pre-Drilled, Wells with a Production Liner and Tie-Back Casing and, Water Producer and Injectors in Utsira and Oligocene [34]. The water producers and injectors are combined to a single category due to similarities in P&A method.

1 Simplified Casing Design
2 Pre-Drilled Wells
3 Wells With a production liner and tie-back casing
4 Water Producers and Injectors in Utsira and Oligocene

Table 10 below presents the type of work required on all the wells on Brage. The applied table is based on the UK Oil & Gas Guidelines [16]. We see that the reservoir has already been plugged on four wells, while the other requires work on every phase. It is also shown that a more complex rig-based work is required on five wells.

Table 10: The Type of Work Required and Associated Complexity of all Wells on Brage.

Brage			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**	**4**			**35**	**1**
	2	**Intermed. abn.**				**35**	**5**
	3	**WH Cond rem**				**40**	

Simplified Casing Design

There are nine wells on Brage that, due to their lower degree of plugging complexity, falls under this category. The simplicity of these wells is related to the fact that the Green Clay formation is behind the 9 5/8” casing, meaning that cut and pull operations are only performed at shallow depths.

Table 11 below summarizes the complexity and type of work associated with these wells. Simple rig-based work is required on every phase, which involves placing a primary and secondary well barrier, retrieving casings shallow, placing an environmental plug and retrieve the conductor. This yields the P&A code PL 3/3/3.

Table 11: The Type of Work Required and Associated Complexity of the Wells with Simplified Casing Design.

Simplified Casing Design **Number of Wells:** 9			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**				**X**	
	2	**Intermed. abn.**				**X**	
	3	**WH Cond rem**				**X**	

Pre-Drilled Wells

The six initial wells on Brage were drilled without the platform and therefore; the casings were hung off in a subsea wellhead. When the platform was installed, the wells were tied back from the seabed through an internal tie-back conductor system [32]. Consequently, the plugging of these wells will involve more complex operations compared to the other wells on Brage. When referring to these tie-back casings, the term *"surface tie-back casing"* will be used. The reason for this increase in complexity will be explained in section 5.1.1.

The complexity and type of work associated with these wells are shown in Table 12 below. What differs from the other wells is related to the additional work due to the internal conductor system. This implies a Type 4 work for placing the environmental plug. This yields the P&A code PL 3/4/3.

Table 12: The Type of Work Required and Associated Complexity for the Pre-Drilled Wells.

Pre-Drilled Wells **Number of Wells:** 5			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**				**X**	
	2	**Intermed. abn.**					**X**
	3	**WH Cond rem**				**X**	

As presented in Table 12, Pre-Drilled wells concerns five wells, instead of six which were the initial number of Pre-Drilled wells. The first well on Brage, A-1, has replaced the internal conductor with an external conductor [32]. Thus, A-1 is no longer associated with the complicated P&A method related to the Pre-Drilled wells.

Wells with production liner and tie-back casing

Several wells on Brage have a well design that includes a production liner and a tieback casing. The tieback casings need to be retrieved to place the dual barrier plug within the Green Clay interval.

Table 13 implies that the required work is identical as for the wells with simplified casing design, i.e. a P&A code PL 3/3/3. However, when looking at the wells at a more detailed level, there are differences that will increase the complexity of the wells with production liner and tieback casing. This is due to the required retrieval of the tieback casing, before placing the barrier plugs. This difference will be dealt with when the more detailed categorization is performed in section 5.1.1.

Table 13: The Type of Work Required and Associated Complexity for Wells with Production Liner and Tie-Back Casing.

Wells with Production Liner and Tie-Back Casing **Number of Wells:** 22			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**				**X**	
	2	**Intermed. abn.**				**X**	
	3	**WH Cond rem**				**X**	

Water Producers and Injectors in Utsira and Oligocene

Four wells on Brage falls under this category, whereof two are water producers, and two cutting/slope injector. The water producers and cutting injector targets the Utsira formation while the slope injector targets Oligocene sandstone. The four wells vary in terms of well design, but have in common, less complex plugging operations required.

As it appears from Table 14 below, no work is to be conducted on the reservoir abandonment phase. However, phase 2 and 3 involves pulling casings shallow, setting the environmental plug and retrieving the conductor.

Table 14: The Type of Work Required and Associated Complexity for Water Producers and Injectors.

Water Producers and Injectors **Number of Wells:** 4			**Abandonment Complexity**				
			Type 0 No work	**Type 1** Simple Rigless	**Type 2** Complex Rigless	**Type 3** Simple Rigbased	**Type 4** Complex Rig-based
Phase	**1**	**Res. Abn.**	**X**				
	2	**Intermed. abn.**				**X**	
	3	**WH Cond rem**				**X**	

5.1.1 A more detailed categorization of the wells

The categorization presented above yields a general overview of the different wells on Brage. However, when further evaluation, such as schedule estimation and sensitivity analysis are to be conducted, a more detailed categorization is necessary. This can be obtained by investigating every single well design in more detail. In the following, the four well categories will, if applicable, be divided further into sub-categories. This sub-categorization is based on features of the well that will alter the plugging procedure. That is: additional operational steps due to retrieval of Annular Safety Valve (ASV), retrieval of 13 3/8" casing due to short 18 5/8" casing, and different milling operation required. The well features will be further explained below.

Retrieval of Annular Safety Valve (ASV):

Several wells on Brage utilize gas lift for more efficient production. When gas lift is used, an ASV is required to function as a gas flow barrier in the annulus [35]. The ASV is part of the production tubing and during P&A, both the production tubing and the ASV must be retrieved. The retrieval method depends on the type of ASV used. On Brage, several types of ASV have been used, leading to different retrieval procedures for the different wells [36]. For simplicity, we can distinguish between two types of ASV: *"old"* and *"new"* type.

If an *old* type of ASV is present, the operational complexity for retrieving the production tubing increases. The ASV is attached with the use of a Concentric Tubing Anchor (CTA), which must be retrieved before further pulling of the tubing can commence. This operation involves pulling out of hole with the tubing and CTA from the cut, which is located between the downhole safety valve (DHSV) and ASV. Once the CTA has been retrieved, a spear can be attached to the tubing and the remaining part can be retrieved [32].

When looking at data from the re-entered wells on Brage, this operation has caused a lot of problems and NPT. This is often due to stuck CTA or stuck tubing, resulting in several cuts before the tubing is fully retrieved [32]. Hence, it is important to differentiate between the wells containing the old and new type of ASV when conducting time estimates. Fortunately, several wells on Brage are equipped with a new type of ASV that involves a far simpler release method.

The new type of ASV is tubing-retrievable, which mean that the tubing and ASV can be pulled as one. The ASV is released by punching the mandrel and pressurize so that the packers retract. The tubing can then be pulled without any additional cuts [32].

The ASV retrieval method leads to the following sub-categories that are added to the first three well categories (the water producers and injectors does not have an ASV):

1) Wells with *"new"* type of ASV or *no* ASV
2) Wells with *"old"* type of ASV

Table 15: Overview of the Wells on Brage in regards to Annular Safety Valves [36]

ASV	New Type of ASV	No ASV	Old Type of ASV
A-1	x		
A-2	x		
A-3		x	
A-4			x
A-5			x
A-6	x		
A-7	x		
A-8	x		
A-9			x
A-10			x
A-11			x
A-12		x	
A-13	x		
A-14	x		
A-15		x	
A-16	x		
A-17			x
A-18	x		
A-19	x		
A-20			x
A-21			x
A-22		x	
A-23	x		
A-24		x	
A-25	x		
A-26		x	
A-27			x
A-28	x		
A-29		x	
A-30			x
A-31			x
A-32	x		
A-33		x	
A-34	x		
A-35	x		
A-36		x	
A-37			x
A-38			x
A-39			x
A-40	x		
Sum	17	9	14

As the number of wells with ASV concerned is high, Table 15 serves to present which type of ASV that is present in the different wells.

Short 18 5/8” casing or 18 5/8” dummy casing:

For most of the wells with simplified casing design, an 18 5/8” dummy casing is installed. The dummy casing does not extend below the seabed. Hence, only the 9 5/8” casing must be pulled shallow prior to setting the environmental plug. However, two wells on Brage has an 18 5/8” casing that extends down below the seabed. Thus, both the 9 5/8” and the 13 3/8” casing must be retrieved shallow before placing the environmental plug in the 18 5/8” casing.

The following sub-categories for wells with simplified casing design is added:

1) Wells with short 18 5/8” casing
2) Wells with dummy 18 5/8 casing

Milling Operations:

As mentioned, the pre-drilled wells on Brage are tied back to the platform through an internal conductor system. The 9 5/8” casing hanger, which hangs in the subsea wellhead, is prevented from being retrieved because it is blocked by the internal conductor. To remove the casing, the internal conductor must be replaced by an external conductor that lays on the outside of the wellhead. This operation was performed on A-1 and turned out to be a very time-consuming operation [32]. With that in mind, it was of great interest to find a solution where the cement plugs could be placed without prior retrieval of casings. The following solution for placing a cross-sectional primary, secondary and environmental plug without prior retrieval of casings is proposed:

Section mill to place the environmental plug

The proposed solution is to section mill both the 9 5/8” and 13 3/8” casing to place an environmental plug in the 18 5/8” casing that extends the whole cross section of the wellbore. This procedure will be applicable for all the pre-drilled wells.

Section mill to place the dual barrier cement plug:

On A-6, the 13 3/8” casing shoe is below the green clay formation. Therefore, the 13 3/8” casing must be section milled in the Green Clay interval, before placing the primary and secondary barrier plug. On well A-2 to A-5, the 13 3/8” shoe is above the green clay and thus, the primary and secondary barriers can be placed in the 9 5/8” casing.

The following sub-categories is added to the *Pre-Drilled Wells*:

1) 13 3/8” casing shoe above green clay
2) 13 3/8” casing shoe below green clay

By the rough and more detailed categorization we are left with the following well types:

1 Simplified Casing Design
- 1.1 New type of ASV or no ASV
- 1.2 Old type of ASV
  - 1.2.1 Wells with 18 5/8” dummy casing
  - 1.2.2 Wells with short 18 5/8” casing

2 Pre-Drilled Wells
- 2.1 New type of ASV or no ASV
  - 2.1.1 13 3/8” casing shoe above green clay
  - 2.1.2 13 3/8” casing show below green clay
- 2.2 Old type of ASV
  - 2.2.1 13 3/8” casing shoe above green clay
  - 2.2.2 13 3/8” casing shoe below green clay

3 Wells With a production liner and tie-back casing
- 3.1 With new type of ASV or no ASV
- 3.2 With old type of ASV

4 Water Producers and cutting injector (Utsira and Oligocene)
- 4.1 Slope Injector
- 4.2 Cuttings Injector
- 4.3 Water Producer

Table 16: Categorization of the 40 Wells on Brage

Well Categories			Procedure #	Number of Wells
1	1.1		1	4
	1.2	1.2.1	2	3
		1.2.2	3	2
2	2.1	2.1.1	4	2
		2.1.2	5	1
	2.2	2.2.1	6	1
		2.2.2	7	1
3	3.1		8	15
	3.2		9	7
4	4.1		10	1
	4.2		11	2
	4.3		12	1

Table 16 above is summarizing the rough and detailed categorization of the wells, along with associated procedure and the number of applicable wells. The procedures with sub-operations, along with the associated well design, are presented in APPENDIX B.

5.2 Plug and Abandonment Operations and Procedures on Brage

The categorization conducted in the previous section can be applied to break the P&A campaign into several procedures in a work breakdown structure. Each categorized well will be assigned a specified P&A procedure that aims to cover the scope of work for that specific well. These procedures will then be the basis for duration estimates for the wells on Brage.

Each procedure consists of a set of required operations. The three phases of well abandonment, along with their associated operations, were briefly described in Chapter 2. However, these are general operational steps and not necessary directly transferable to the required operation on Brage. Therefore, it is naturally to describe the relevant operations in more detail before assigning procedures to each well. The purpose of the section below is to give the reader an understanding of each operational step and thus, the relevance of the different steps presented varies from one well to another.

5.2.1 General P&A operations on Brage

Intervention

The intervention phase involves killing the well, placing deep and shallow mechanical plug, cutting the tubing, punch and release the ASV and displacing the annulus above the packer to brine [34].

The well is killed by bullheading fluids into the well and force the production fluids into the reservoir. After the well is killed, the deep set mechanical plug is set. This acts as a temporary barrier against the reservoir. Next, the ASV is punched to create communication and to release the ASV. The well is then displaced to brine. The tubing is then cut deep, i.e. just above the production packer. The last step in the intervention phase is to set the shallow mechanical plug to have two barriers against the reservoir when the XT is removed [34]. This is in accordance with NORSOK D-010.

The phase presented above is as mentioned performed by the intervention department. The remaining phases are conducted by the drilling and well department, which is the department this thesis was provided by. However, the intervention phase is included in this thesis to capture the whole well abandoning process. The remaining operational steps will be described in the following and are based on Fjelde's master thesis [34], "End of Well Reports" [32] and conversations with drilling engineers at Wintershall [37].

Removal of XMT and Installation of BOP and Risers

The wellhead is removed before the BOP, high-pressure riser and low-pressure riser are installed. When removing the shallow set mechanical plug to perform further P&A activities, a BOP is required to maintain well control and to fulfill the requirement of two barriers against the reservoir.

Retrieve or Pump Open the Shallow-set Plug

The shallow set plug must be removed before further P&A activities can commence. Depending on the mechanical plug installed, this could be conducted in several ways. The plug can be physically retrieved or pumped open depending on the type used.

Pull Production Tubing:

To place a cement plug extending across the entire wellbore, the production tubing must be retrieved. The tubing is retrieved from the deep cut performed in the intervention phase. The retrieval method will depend on the type of ASV present in the well. The two retrieval methods were described in Section 5.1.1.

Log Casing in Green Clay Interval

Logging is performed to verify sufficient bonding of the Green Clay to the casing. A Cement Bond Log (CBL) and Ultra Sonic Imager Tool (USIT) are used to evaluate the Green Clay in the interval where the internal barrier plugs are placed.

Cut and Retrieval of Tie-back Casing Deep

This operation is required for the wells with production liner and tie-back casing. The tie-back casing must be retrieved to place the primary and secondary cement plug that extend across the entire well bore. The casing will be cut with a cutting assembly and retrieved by running in hole with a spear assembly.

Place Mechanical Casing Plug as Foundation for Cement Plugs

A mechanical casing plug is placed to serve as a foundation for the following primary and secondary cement plugs. The casing plug is pressure tested and hence, pressure testing of the cement plugs is not necessary [4].

Set Primary and Secondary Cement Plugs in the Green Clay Interval

The primary and secondary plugs are placed to meet the requirements of two barriers against the source of inflow. The plug is placed by running in hole with a cement stinger before cement is pumped down the well. As the primary and secondary plug is placed as one, continuous plug, the plug shall be dressed off after the cement is set [4]. The dressing is performed by drilling the cement plug until hard cement is encountered.

Nipple Down (N/D) the Tubing Head

To retrieve the casings, the tubing head (where the production tubing is landed in the wellhead) must be removed.

Cut and Pull Casings Shallow

To make sure that the "open hole to surface," or environmental plug extend across the entire wellbore, casing strings must be cut and retrieved from shallow depth. This is conducted by running in hole with a cutting assembly. The casing is cut before the cutting assembly is pulled out of hole. Then a spear assembly is run in hole to retrieve the casing.

Section Mill 9 5/8" and 13 3/8" casing

This operation only concerns the wells A-2 to A-6. Cut and retrieval of the 9 5/8" and 13 3/8" casing is not preferred due to the difficulties associated with the process (as explained in section 5.1.1), and hence, dual section milling is performed before placing the primary and secondary barrier plugs. This is conducted by running in hole with a milling tool that can perform dual section milling.

Log Environmental Plug Setting Interval

If data regarding cement volumes which indicates that the 18 5/8" casing is cemented to surface, this operation is not required. If this is not the case, logging is required to verify that the casing cement is sufficient to act as an external barrier [4].

Place Mechanical Casing Plug as Foundation for Environmental Plugs

A mechanical casing plug is placed to serve as a foundation for the following environmental plug. The casing plug is pressure tested and hence, pressure testing of the environmental plug is not necessary [4].

Set Environmental Plug

The cement plug is placed in the same way as the primary and secondary cement plugs. The length requirement for the environmental plug is 50 m since the cement plug is placed on a mechanical casing plug. The environmental plug is then verified by tagging.

Cut and Retrieval of Conductor and Internal Casings

This final phase is conducted in the following way. The internal casing strings are first cut and retrieved before the conductor are cut and retrieved. An alternative method could be to cut and retrieve all tubulars at once. The condition of the tubulars concerned will, among others, decide which alternative that will be more efficient.

5.2.2 The P&A Procedures for the Different Wells on Brage

The operations described above will not be applicable for every well on Brage. The procedures for each well category along with their sub-operations will be listed in APPENDIX B. In the following, flow charts that are based on the detailed categorization in section 5.1.1 is presented. The flow charts will determine the procedure applicable for the different well types.

P&A Procedures for Simplified Casing Design

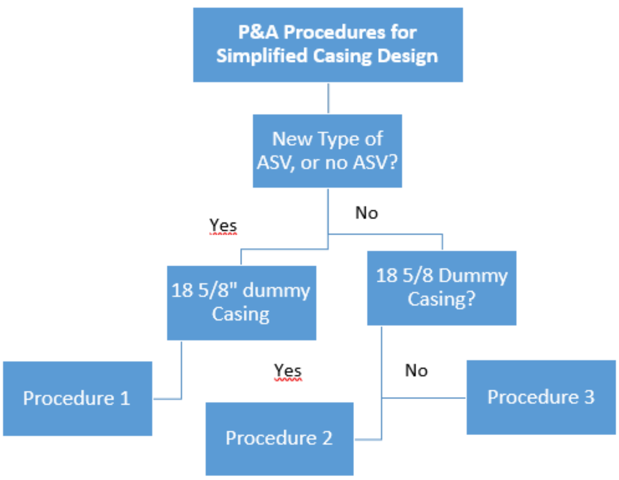

Figure 26: Selection of Procedure for Simplified Casing Design

P&A Procedures for Pre-Drilled Wells:

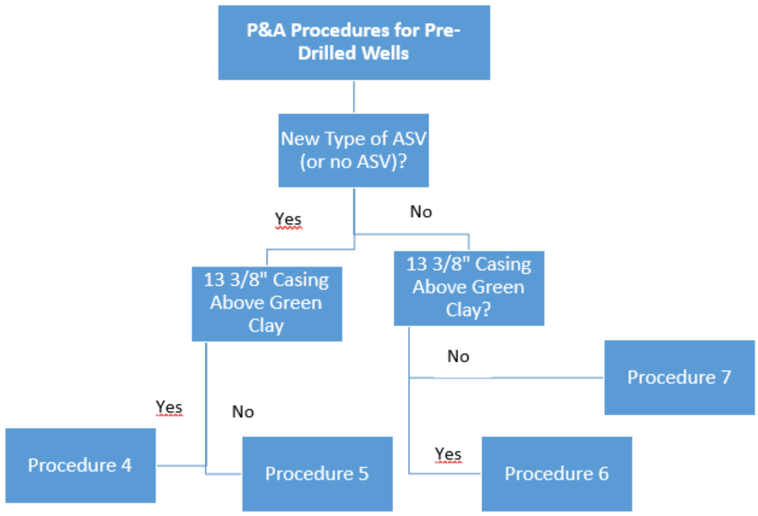

Figure 27: Selection of Procedure for the Pre-Drilled Wells

P&A Procedures for Wells with Production Liner and Tieback Casing:

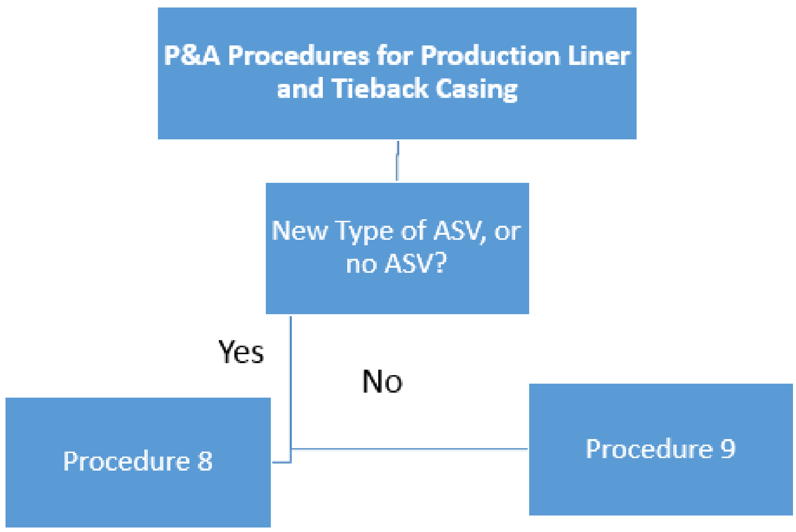

Figure 28: Selection of Procedure for Wells with Production Liner and Tie-Back Casing

P&A Procedures for Water Producers and Injectors

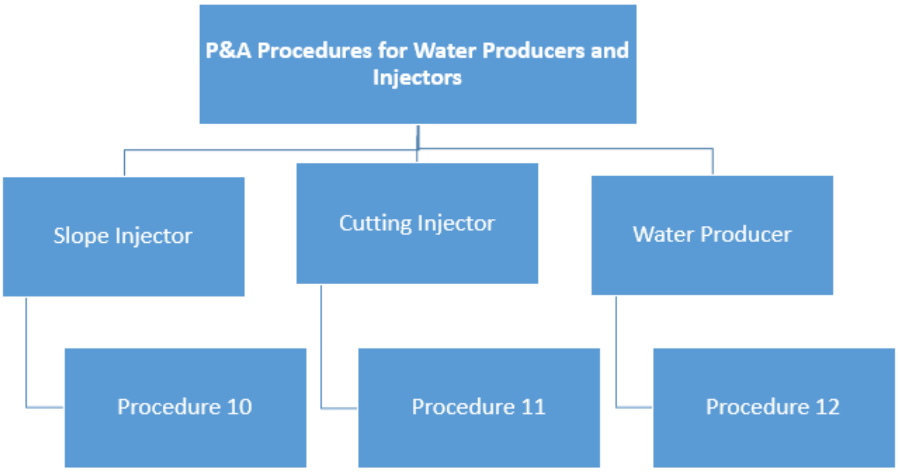

Figure 29: Selection of Procedure for Water Producers and Injectors

5.4 Possible Unexpected Events on Brage

The selected unplanned events for P&A on Brage are listed in Table 17 below. These events are based on historical incidents and expert opinions [32] [38]. In the following, these events will be described further.

Table 17: List of Likely Unplanned Events Associated with P&A on Brage [38].

Event	**Consequence**
Stuck Tubing	Perform multiple cuts to retrieve the tubing.
Problems to Cut & Retrieve Casing	Perform multiple cuts to retrieve the casing.
Poor Cement Job	Wash/drill and set new plug.
Section Milling Fails (shallow)	Re-run.
Insufficient Green Clay Bonding	Section mill to get exposure to formation before placing new plug.
Section Milling Fails (deep)	Re-run.
Problems Retrieving WH, Conductor & Casings	Perform multiple cuts to retrieve tubulars.

Problems Retrieving ASV/CTA:

There have been several incidents recorded on Brage that relate to stuck tubing. The issue is often caused by the annular safety valve (ASV) [32]. This were explained in Section 5.1.1. However, the tubing can be stuck for other reasons than the ASV as well, e.g. due to a tubing in poor condition. Therefore, the event of stuck tubing is assigned to every procedure where the tubing is to be removed. Nevertheless, the probability of occurrence is set to a higher value for the wells with an "old" type of ASV, compared to those wells with no or "new" type of ASV.

Cut and Retrieve Casings:

The problems related to stuck casing can be several. The actual cut may be insufficient due to tool failures or misplacement, leading to re-cuts. Problems related to not being able to attach to the casing with a spear may also be encountered. If the annulus behind the casing to be retrieved is filled with old mud and settled particles, this may also hamper the retrieval process. The solution to this will often be to perform multiple cuts and retrieve the casing partwise. For the wells with a production liner and tie-back casing, the annulus is filled with brine. This simplifies the process [38].

Poor Cement Job

If the cement job for placing the cement plug is poorly conducted, this can be indicated through pressure test or when the plug is tagged and dressed, a new cement plug must be placed. This may involve a wash-out of the well before the new plug can be set [38].

Section Milling Fails

Section milling failure may cause severe non-productive time. Section milling creates vibrations which may cause the cutters to wear. This may lead to several re-runs. The created swarf may also cause problems in relation to swarf handling and swarf clusters in the BOP. As a result, time is lost to rinsing of the BOP [38].

Insufficient Green Clay Bonding

If the logs conducted in the Green Clay interval indicates poor bonding between the formation and outer casing, actions must be taken. As mentioned earlier in this thesis, section milling can serve as a solution. As stated above, section milling is a complex operation and several problems may be encountered. Hence, a substantial amount of NPT may be expected [38].

Problems Retrieving WH, Conductor & Casings

If the tubulars to be retrieved a few meters below seabed are in poor condition, problems may be encountered in the retrieval process. This may cause several cuts to be performed, before all tubulars can be retrieved. Even though the retrieval is conducted at shallow depths, the consequence may be an appreciable amount of NPT [38].

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6 Data Collection

Collecting input data for the estimation model is one of the most challenging part of the estimation process. Fortunately, many of the operations required in the abandonment process on Brage, have previously been performed when wells have been plugged back and re-entered at a later point in time. Consequently, Wintershall possess a great amount of duration data that can be applied for the forecast modelling. Duration data from the abandonment of the Murchison field will also be evaluated to capture learning and the operations that are not previously conducted at Brage. In this chapter, the method for collecting and applying these data will be described. In addition, the method for collecting durations for unplanned events and general NPT will be described.

6.1 Selecting Adequate off-set Wells

Like mentioned in Chapter 3, it is important that the historical duration data used is adequate to the considered project [25]. Differences in terms of field, type of platform used, subsurface pressure regimes, well design and so on must be evaluated when selecting relevant off-set wells. For instance, operations conducted at a double derrick platform are likely to be more efficient than for a single derrick platform. Retrieving the conductor using a dedicated vessel may be easier than retrieval from a fixed platform etc. Another thing to consider is the technology used. Are the historical duration data based on using old technology no longer relevant for today's operations? However, by applying the duration data from previous operations on Brage, we assure that these data will be more applicable than data from another field.

6.2 Collecting Historical Data

Collecting Historical Data from Previous Operations on Brage

As mentioned, most of the input data used in the estimation model are collected from previous experience from re-entries on Brage. Re-Entry of old wells has been conducted at Brage for a long time and some of the duration data used goes all back to the Norsk Hydro period. However, for applicability assurance, most of the data used are from more recent slot recovery campaigns.

The duration data are collected from End of Well Reports, Daily Drilling Reports (DDR), and other available data bases.

Collecting Historical Data from the Abandonment of Murchison

The well abandonment campaign on Murchison field on British sector started October 2013. The steel jacket platform was installed in 1979 and consisted of 33 wells [39]. Due to the similarities between the Murchison and Brage platform, some duration data from this abandonment project are also collected to use in the forecasting model in this thesis. The collected data are in relation to the conductor removal process, since this operation has not been previously performed at Brage. To evaluate the possibilities of learning throughout a P&A campaign, a learning curve is also established for the Murchison abandonment. This will be further described in section 6.4.

6.2 Expert Opinions

As mentioned in Chapter 3, if the off-set data are inadequate, the use of expert opinions can come in handy [24]. However, when relying on expert opinions, there are some pitfalls that needs to be considered. Akins et al. [24] states that experts may be biased due to negative or positive experiences with a certain operation. The experts may also be overly confident in their capability in assessing uncertainty. In addition, the outcome range tends to be too narrow when relying on expert opinions. Hence, the uncertainty should be assessed by as many experts as possible [24].

For this thesis, the duration data obtained from historical records were reviewed and assessed by the several drilling engineers at Wintershall. Their knowledge relates to the durations of operations that have been previously conducted at Brage, as well as their experiences from operations at other oil and gas fields. The unplanned events, along with their probability of occurrence and possible durations were also assessed together with experts from Wintershall. The method for establishing these events will be described in the next section.

6.3 Unexpected Events

The possible unplanned events relating to P&A on Brage are described in Chapter 5.4. These are as mentioned defined by looking at historical incidents and assessing other likely events associated with certain operations. As these events are to be isolated and presented individually in the estimation model, it is important to exclude these events when gathering the duration data from historical operations. If a major unplanned event, such as "Stuck Tubing," is present in the data set, the duration of this event is extracted from the data set. If the duration is not extracted from the data set, we will risk counting this duration twice, as we are adding the duration of unplanned events separately in the model. This is also the case when adding up the duration of general NPT. Consequently, all operational durations collected is excluding the non-productive time and is only concerning the "trouble-free" duration of an activity.

6.4 Method for Capturing the Learning Effect

For evaluation of the possible effect of learning, the Brett and Millheim method [30] is applied to the duration data on the Murchison field. This method is described in Chapter 3, Section 3.4.2. The first step in learning curve establishment is to chronological list the duration for the 33 wells. Then we give a first guess on the C-parameters to establish a first-guess learning curve. The squared error is then calculated before selecting the C-parameters minimizing this error. This yields the estimated learning curve. The parameter of importance for the estimation on Brage, is the C_2 value. Recapping the theory of learning curves, this value represents the speed of learning for an organization [30].

The establishment of the learning curve for Murchison is summarized in Fig.30 below and is conducted in the same way as described in Section 3.4.2. Keeping in mind the wide variety in abandoning durations for the different wells on Murchison, estimating a learning curve with great fit to the actual data is difficult. The wide variety in durations may be caused by several factors. By categorizing the wells based on complexity and operations, like conducted for Brage in this thesis, one could potentially have obtained a better representation of the learning. Due to lack of information, this was not conducted for the duration data on Murchison. The estimated learning curve on Murchison yielded a C_2 value of 0.18, which mean a slower learning rate than the industry standard, which was found to 0.34 by Brett and Millheim [30]. However, we must keep in mind that the industry standard learning rate of 0.34 is associated with drilling operations, and could potentially be different for P&A activities. In addition, the fact that the wells on Murchison were not categorized could potentially misrepresent the true learning. Due to the similarities between Brage and Murchison, the thesis therefore assumes a C_2 value representing the average between the industry standard, and the value obtained from the Murchison field. That is, a C_2 value of 0.26.

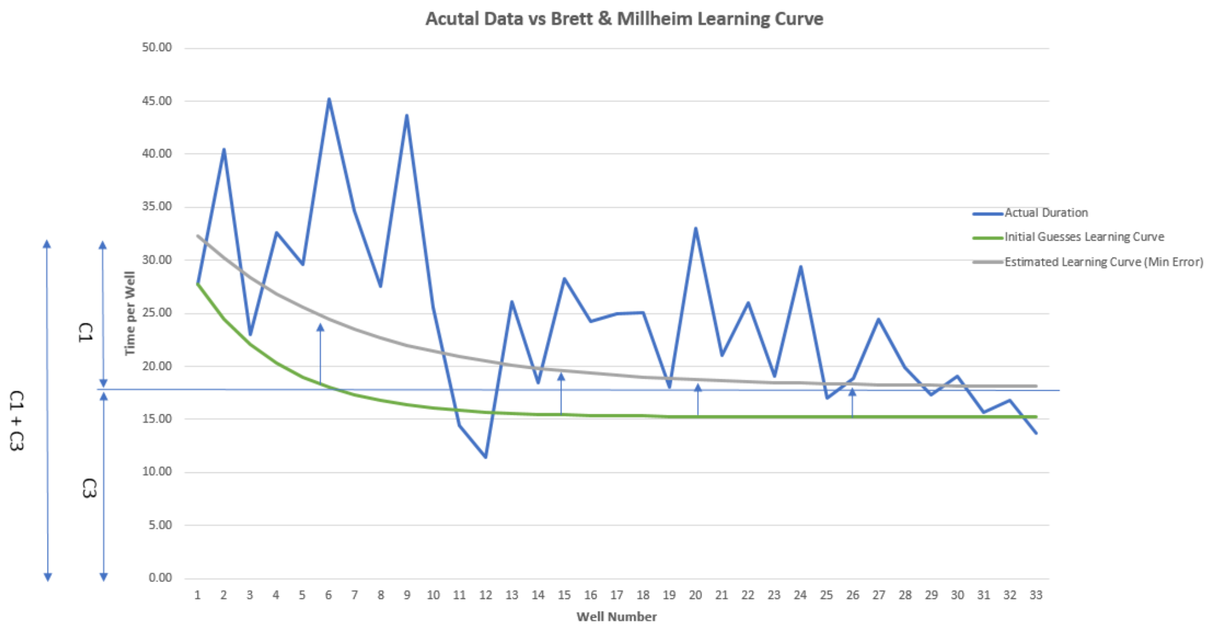

Figure 30: Establishment of Learning Curve for P&A of the Murchison Field

6.5 Selecting Minimum, Most likely and Maximum Values from the Data Set

Up to now, the chapter has considered how the input data used in the estimation model is collected. Historical durations for well activities along with durations for different unplanned events and general NPT are gathered. To use these data in the estimation model, they must be assigned a probability distribution which in this thesis will be a triangular distribution. Therefore, minimum, most likely and maximum values must be established. Recapping the Monte Carlo pitfalls presented in Chapter 3, we must choose a range that extend beyond the minimum and maximum durations from the data set [25]. The calculation method described through expression 3.2 - 3.6 is used in this thesis. Fig.31 below summarizes how this calculation is performed in Excel. The numbers presented in Fig.31 are only serving as a fictional example.

This method will be applied to the planned operation durations, unplanned events and general NPT. However, expert opinions will also be considered when determining these values.

Well #	Duration (hrs)
1	18
2	20
3	24
4	28
5	30
6	35
7	24
8	23
9	27
10	29
11	28
12	31
13	24
14	26

	(hrs)
Mean	26.21
SD	4.48

6SD^2	120.16
3/4(mean-min)^2	94.32
(3*mean-min)/2	31.82
Sqrt((3*mean-min)/2 - 3/4(mean-min)^2)	5.08

Minimum	(hrs)
Lower Limit	13.56
Upper Limit	19.89

Choose a minimum

Minimum 15

	(hrs)
Minimum	15.0
Likely	26.7
Maximum	36.9

Figure 31: Method for Determine the Minimum, Most Likely and Maximum Value for the Triangular Distribution

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7 The Estimation Models

The objective of this thesis is to establish accurate and reliable time estimate of P&A operations on Brage. As stated in previous chapters, a lot of factors will affect how accurate the estimates are and thus, it is important to establish a proper model that aims to cover most of these factors. In the following, three different probabilistic models will be presented. All three models are based on the operational procedures described in Chapter 5, the data collection described in Chapter 6, and the probabilistic approach explained in Chapter 3. However, they differ in terms of inclusion and exclusion of unexpected events and learning. The structure of each model will be explained along with the underlying assumptions.

7.1 Model 1 - Excluding Risk and learning

To evaluate how the inclusion of unplanned events will affect the time estimates, we must first create a base model. This model excludes the effect from both unplanned events and learning and thus, the estimates obtained are not likely to fully reflect the actual duration of the future P&A campaign. Although the model does not include these two factors, it will still, due to the probabilistic approach, cover a greater span of possible outcome. The objective of the model is to create an estimate for the total duration of the P&A campaign on Brage, without considering the effect of learning and unplanned events. Based on the historical data, we will obtain a probability distribution curve that reflects the range of different outcomes. The model will also provide information regarding which operation that are most sensitive for changes, through a tornado chart.

Fig.32 presents the model set-up for Procedure 8 and contains the operational procedure and the associated duration inputs. A distinctive model will be assigned each operational procedure presented in chapter 5, and will aim to cover the required sub-operations. By running the Monte Carlo Simulation, the software will predict a duration, based on the underlying three input values, for each sub-operation. This value will appear on the column named *Probabilistic Duration.* The predicted duration for each sub-operation will be added to form the total duration as explained through expression 3.1 in Chapter 3. This process will be conducted 50 000 times, for achieving more accurate estimates.

Procedure 8				
Operations	Minimum (days)	Most Likely (days)	Maximum (days)	Probabilistic Duration (days)
Skid Rig	0.04	0.17	0.33	0.13
Intervention	2.50	4.13	5.63	4.81
Remove XT (offline)	0.04	0.13	0.50	0.21
N/U BOP/Riser & P-test	0.50	0.71	1.17	0.75
Pump open shallow plug	0.05	0.13	0.17	0.08
Pull Upp Compl to cut	0.63	1.50	2.63	2.21
Set shallow mech plug	0.04	0.09	0.44	0.15
N/D BOP	0.13	0.38	0.96	0.51
N/D Tubing Head	0.04	0.17	0.38	0.21
N/U BOP/Riser & P-test	0.17	0.42	1.17	1.11
Retrieve shallow mech plug	0.04	0.09	0.44	0.08
Cut and pull tie-back casing	1.88	2.71	3.42	2.75
Log 13 3/8" casing	0.33	0.67	1.38	0.85
Set 13 3/8" casing plug	0.38	0.75	1.33	0.48
Set cement plug	0.50	1.04	2.38	1.51
Tag Plug	0.63	0.88	2.50	1.2
Cut and retrieve 13 3/8" shallov	0.83	1.13	1.42	0.95
Set Plug As base in 18 5/8"	0.25	0.50	0.83	0.7
Set Environmental plug	0.33	0.63	1.25	1.15
Tag plug	0.42	0.58	0.75	0.61
Conductor & casing Removal	2.00	4.00	8.00	4.62
Total Duration (days)				16.29

Figure 32: Snapshot of Estimation Model 1 from Excel.

7.1.2 Assumptions

Some assumptions must be made. First, the model will not consider the effect of unplanned events, nor the contribution from general NPT and WOW. In addition, the model will not evaluate how the learning from the first well, affects the total duration for the subsequent wells. Another assumption is regarding correlations. The Monte Carlo simulation itself, will treat the different operations as independent. I.e. the duration of one operation will not affect the duration of the next operation and so on [24]. However, we could in reality expect the correlation between the different activities to be nonzero. The model also assumes that the correlation between the total duration of the different wells in the campaign, is set to zero.

7.2 Model 2 - Including Risk

For the model including risk, the base model is extended with additional lines to represent unplanned events and general NPT. The unplanned events included will vary from one procedure to another, and can be found in APPENDIX C. The general NPT will be the same for all procedures. The risk severity of both the general NPT and unplanned events is given through a triangular distribution. The general NPT is given as a *percentage* while the unplanned events are given in *days*. We then define the likelihood of occurrence and simulate this occurrence through a binomial distribution. The duration of the unplanned events and general NPT is then added to the total duration. The general NPT duration can take any value between 3, 6.5 and 14%, with a probability of occurrence of 85%. These numbers are based data from similar activities on Brage. The general NPT percentage is added to the total duration excluding duration of unplanned events.

Procedure 8				
Operations	Minimum (Days)	Most Likely (Days)	Maximum (Days)	Probabilistic Duration (Days)
Skid Rig	0.04	0.17	0.33	0.13
Intervention	2.50	4.13	5.63	4.81
Remove XT (offline)	0.04	0.13	0.50	0.21
N/U BOP/Riser & P-test	0.50	0.71	1.17	0.75
Pump open shallow plug	0.05	0.13	0.17	0.08
Pull Upp Compl to cut	0.63	1.50	2.63	2.21
Set shallow mech plug	0.04	0.09	0.44	0.15
N/D BOP	0.13	0.38	0.96	0.51
N/D Tubing Head	0.04	0.17	0.38	0.21
N/U BOP/Riser & P-test	0.17	0.42	1.17	1.11
Retrieve shallow mech plug	0.04	0.09	0.44	0.08
Cut and pull tie-back casing	1.88	2.71	3.42	2.75
Log 13 3/8" casing	0.33	0.67	1.38	0.85
Set 13 3/8" casing plug	0.38	0.75	1.33	0.48
Set cement plug	0.50	1.04	2.38	1.51
Tag Plug	0.63	0.88	2.50	1.2
Cut and retrieve 13 3/8" shallow	0.83	1.13	1.42	0.95
Set Plug As base in 18 5/8"	0.25	0.50	0.83	0.7
Set Environmental plug	0.33	0.63	1.25	1.15
Tag plug	0.42	0.58	0.75	0.61
Conductor & casing Removal	2.00	4.00	8.00	4.62
Total Duration				17.99

Total Duration (Days)	
Without Risk	17.99
With Risk	22.63337

Unexpected Events	Minimum (days)	Most likely (days)	Maximum (days)	Risk Severity (days)	Likelihood (%)	Simmulated occurance	Risk Occurs? (yes/no)	Risk Amount (days)
Stuck Tubing	0.5	1	3	1.21	20	1	Yes	1.21
Unsufficient Green Clay bonding	5	7	10	8.35	10	0	No	0
Poor Cement job	2	3	5	2.21	10	0	No	0
Problems Retrieving Tie-back	0.5	0.8	2	0.92	10	0	No	0
Problems retrieving WH	0.5	2	5	2.3	10	1	Yes	2.3
Total Risk Amount								3.51
General NPT	Minimum	Most likely	Maximum	Risk Severity	Likelihood (%)	Simmulated occurance	Risk Occurs? (yes/no)	Risk Amount
General NPT (%)	3	6.5	14	6.3	85	1	Yes	6.3

Figure 33: Snapshot of Estimation Model 2 from Excel.

The following occurs when we perform *one* trial of the Monte Carlo simulation and summarizes Fig.33:

1) The software predicts a duration for each sub-operation based on the triangular distribution. This is added up to form the total (encircled in yellow).
2) The software predicts if the unplanned events and general NPT occurs or not. This is based on the probability assigned.
3) The software also predicts a duration and percentage of the unplanned events and general NPT respectively. These are based on the triangular distribution.
4) If the event occurs, the duration and percentage predicted appears at the *Risk Amount* column.
5) The value encircled in green includes the total planned duration (encircled in yellow), the total duration of unplanned events, and the general NPT amount. The amount of general NPT is a percentage of the total planned duration.
6) A trial is conducted 50 000 thousand times.

7.2.2 Assumptions

As for the base model, we do not consider the effect of learning from one well to another. The assumptions regarding correlation is also applicable for this model. For simplicity, lost time due to waiting on weather (WOW) is not considered in this model. Since Brage is a fixed platform, we assume that WOW will not be a substantial contributor to the total duration.

7.3 Model 3 - Including risk and learning curves

The last model is established to reflect the effect from both learning and uncertain events. This model aims to estimate the total duration of the P&A campaign better than the two previous models, both in terms of accuracy and by providing more useful information. Model 3 is identical to Model 2 in terms of set-up, but differs in the method for adding up total duration for each well category. The addition sequence for the considered well category is based on the Brett and Millheim method to include the effect of learning [30].

Based on the abandoning data from Murchison, a learning curve were established in accordance with the Brett and Millheim method. The method for determining the C_2 value for Brage were described in Chapter 6. The next parameters could be established through a deterministic or probabilistic approach. If we are confident, based on previous obtained results and expert opinion, on the value of these parameters, we can use a deterministic approach [28]. The C_3 value, or the technical limit, will be based on the simulations from Model 2 and expert opinions. The C_1 value will then be the difference between duration of the first well and the C_3 value.

The model will, for each trial of the simulation, randomly draw a duration for the first well and calculate the duration of the following wells through the Brett and Millheim expression 3.8.

Consider the following fictional example. A well category consists of 10 wells, where the C_3 value is set to 26 and the C_2 value to 0.3. During the first trial, the software predicts a value of 30 days as the duration of well number one. This implies that $C_1 = 4$. The model then calculates the duration, based on the three parameters, for the remaining 9 wells (see Fig.34). Such a trial will be conducted 50 000 time to yield the aggregated distribution for that well category.

Learning	
Well Number	**Duration (Days)**
1	30.00
2	28.96
3	28.20
4	27.63
5	27.20
6	26.89
7	26.66
8	26.49
9	26.36
10	26.27
Sum	**274.66**

Learning Parameters	
First Well Draw (days)	30.00
C1	4
C2	0.3
C3	26

Figure 34: The Method for Including Learning in Model 3.

7.3.2 Assumptions

In addition to the assumptions regarding correlations, we must make some further assumptions regarding the learning. To take advantage of the learning, we must assume that the time between the abandonment of each well, is sufficient to implement the learnings. In addition, the effect of learning is only applied to Procedure 8 and 9, which contain the greatest number of wells, 15 and 7 wells respectively. In reality, we could expect learning on all 39 wells, due to the fact that several operational steps are similar in the 12 procedures. However, the thesis only considers Procedure 8 and 9 to show the effect of learning on the estimates. The last assumption relates to the C_2 value. As explained in Chapter 6, the estimated C_2 value from the abandonment on Murchison is 0.18, which indicated poor learning. However, the industry standard is 0.34 according to Brett and Millheim [30]. For the estimation model on Brage, we assume a C_2 value of the average between those two values, that is 0.26.

8 Results

This chapter presents the results from the three models described in Chapter 7. First, the duration for certain procedures will be presented through a probability-density function (PDF), along with their associated means and percentiles. The estimates will be presented for the case with no risk, together with the case including risk. Second, the aggregated duration estimates for Procedure 8 will be presented to show the effect of learning. The last result presented is the total duration for P&A on Brage. The duration estimates for the procedures not listed in this Chapter can be found in APPENDIX D. An overview of the wells on Brage along with their associated procedure can be found in Table 18 below. The procedures are listed in APPENDIX B.

Table 18: Overview of the Wells on Brage Along with their Associated Procedure.

	Procedure 1	Procedure 2	Procedure 3	Procedure 4	Procedure 5	Procedure 6	Procedure 7	Procedure 8	Procedure 9	Procedure 10	Procedure 11	Procedure 12
A-1								x				
A-2				x								
A-3				x								
A-4							x					
A-5						x						
A-6					x							
A-7								x				
A-8								x				
A-9									x			
A-10									x			
A-11									x			
A-12	x											
A-13								x				
A-14								x				
A-15										x		
A-16								x				
A-17									x			
A-18								x				
A-19								x				
A-20									x			
A-21		x										
A-22								x				
A-23								x				
A-24											x	
A-25	x											
A-26	x											
A-27			x									
A-28								x				
A-29											x	
A-30		x										
A-31									x			
A-32								x				
A-33												x
A-34								x				
A-35								x				
A-36	x											
A-37									x			
A-38		x										
A-39			x									
A-40								x				
Sum	4	3	2	2	1	1	1	15	7	1	2	1
	Simplified Casing Design			Pre-Drilled Wells				Prod. Liner and Tie-Back		Water Prod. And Injectors		

8.1 Duration Estimates for Some Operational Procedures with and without Risk

Procedure 1

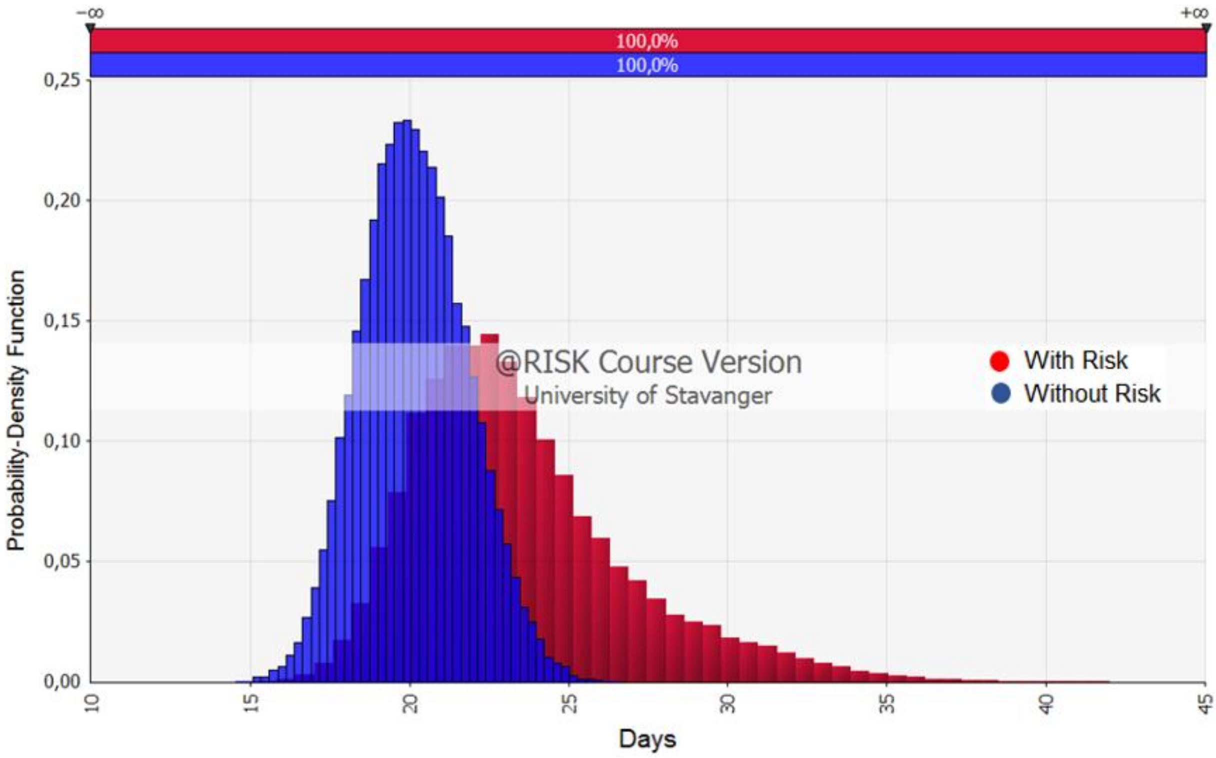

Figure: 35 The Probability Density Functions for Procedure 1

Table 19: The Statostic Values for Procedure 1

Statistic Values	Without Risk (days)	With Risk (days)
Mean	20,2	23,6
P10	18,1	19,9
P50	20,1	22,9
P90	22,4	28,2
Standard Deviation	1,66	3,3

From Fig.35 we see that the inclusion of risk shifts the PDF curve to the right. In addition, the skewness of the curve establishes a longer tail to the right. This effect is as expected and consistent with the theory explained in Chapter 3. We see that the inclusion of unplanned events and general NPT causes an increase in the mean duration of 3.4 days.

Procedure 2

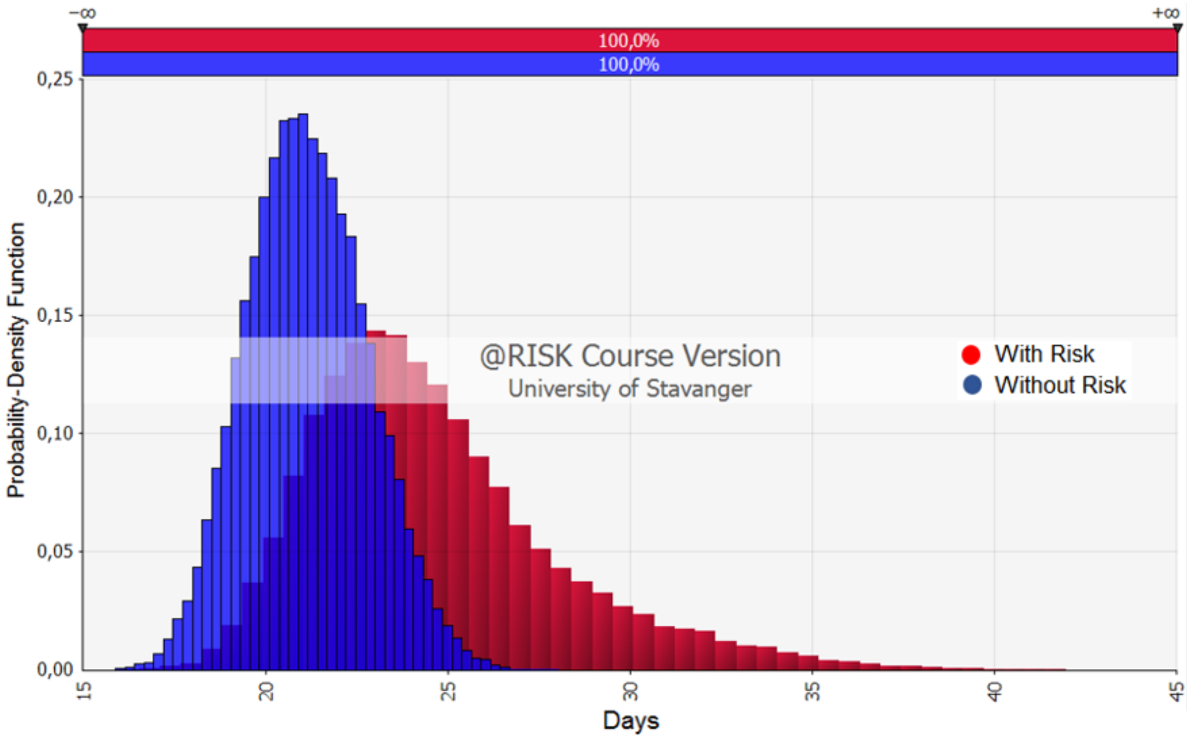

Figure 36: The Probability Density Functions for Procedure 2

Table 20: The Statistic Values for Procedure 2

Statistic Values	Without Risk (days)	With Risk (days)
Mean	21,1	24,6
P10	19,1	20,9
P50	21,1	23,9
P90	23,3	29,2
Standard Deviation	1,65	3,4

From Fig.36 we see the same effect of including risk as for Procedure 1. We see that the mean duration is greater than for Procedure 1 by approximately one day. This is due to the additional operational step involving removal of the “old” type of ASV. This removal process will also involve more uncertainty in terms of greater likelihood of stuck tubing.

Procedure 5

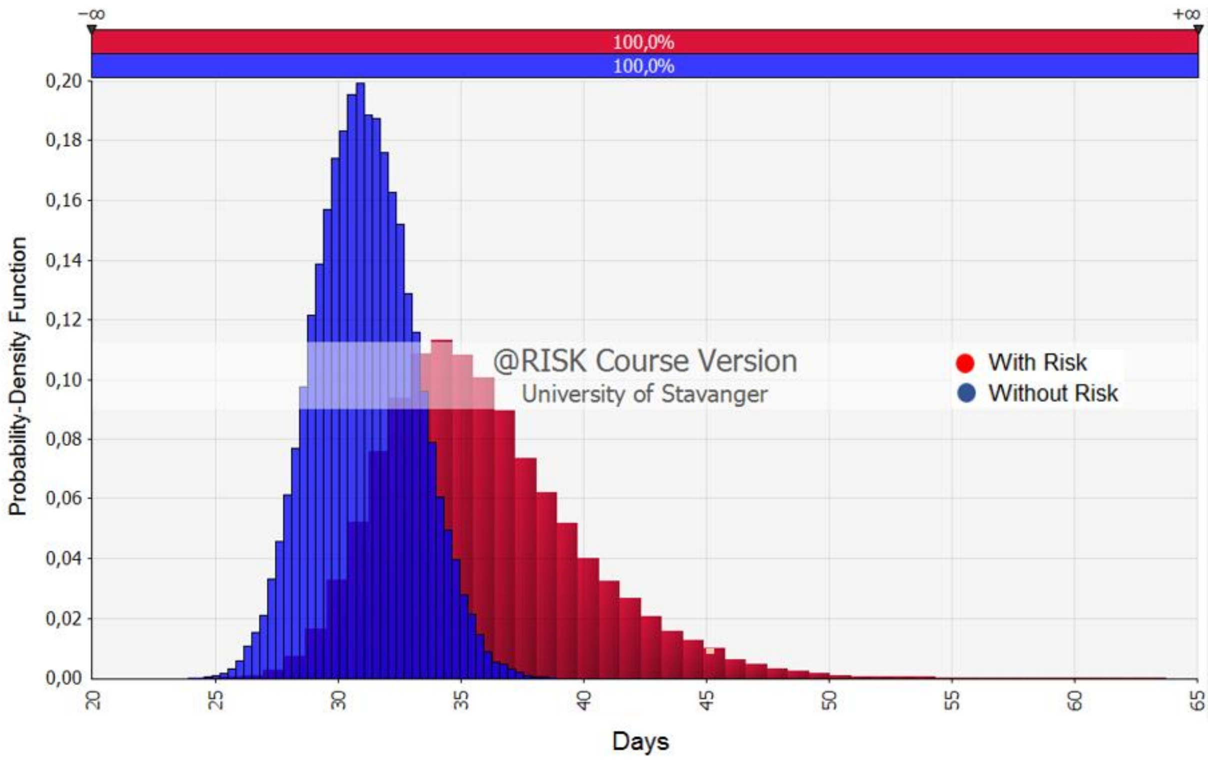

Figure 37: The Probability Density Functions for Procedure 5

Table 21: Statistic Values for Procedure 5

Statistic Values	Without Risk (days)	With Risk (days)
Mean	31,1	35,8
P10	28,5	31,3
P50	31,0	35,3
P90	33,7	41,2
Standard Deviation	1,9	3,9

Procedure 5 involves both section milling of two casings shallow and section milling of the 9 5/8" casing in the Green Clay interval. This category is assumed to be the most complicated and time-consuming well category. This is reflected through the highest estimated mean value. The effect of including risk is greater for Procedure 5 compared to Procedure 4 (see APPENDIX D). This is due to the uncertainty related to the additional sequence of section milling deep. This is also reflected through the greater standard deviation.

Procedure 11

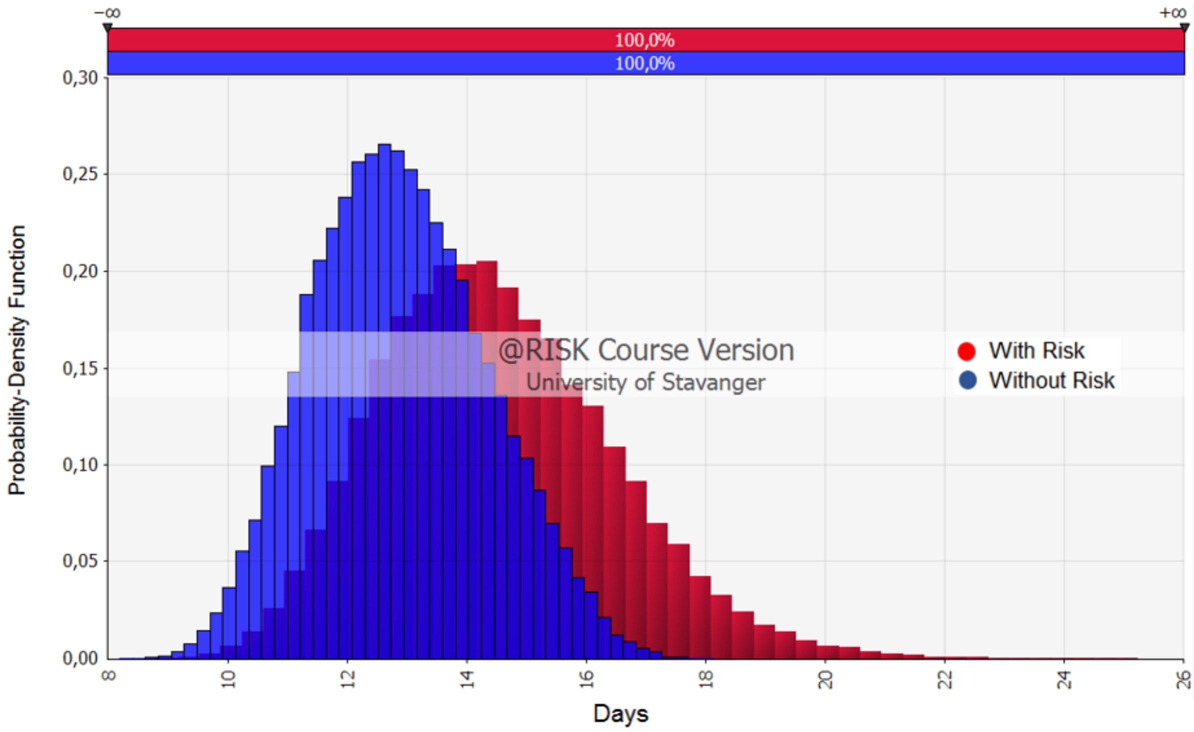

Figure 38: The Probability Density Functions for Procedure 11

Table 22: Statistic Values for Procedure 11

Statistic Values	Without Risk (days)	With Risk (days)
Mean	12,9	14,5
P10	11,0	12,1
P50	12,8	14,3
P90	14,9	17,1
Standard Deviation	1,4	1,9

The Utsira water producers A-24 and A-29 involves the least operational steps of all the wells on Brage. It is also exposed for the least amount of uncertainty. This is clear through the similarity in standard deviation for the two cases presented in Table 22. The two curves in Fig.38 is coinciding of a greater extent than for the other presented in this chapter.

8.2 Procedure 8 applied to 15 Wells for evaluating the effect of learning

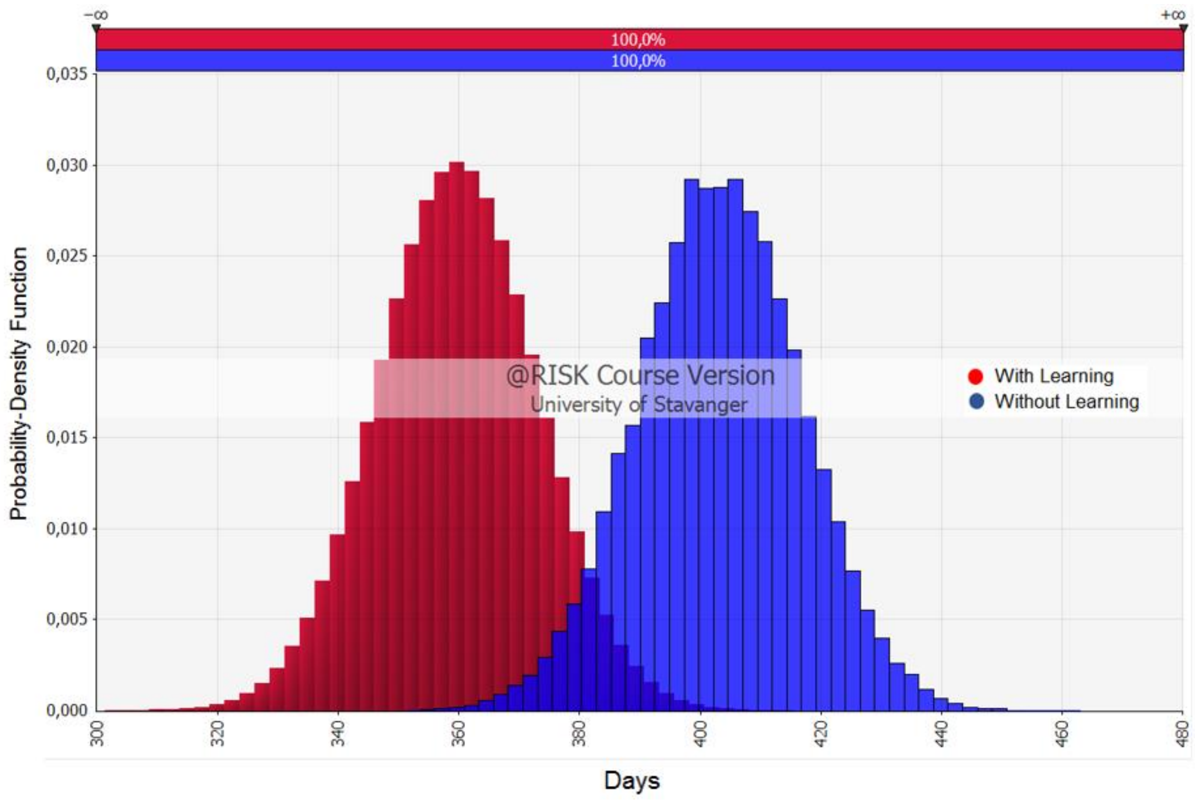

Figure 39: The Probability Density Functions for 15 Wells Associated with Procedure 8

Table 23: Statistic Values for 15 Wells (Procedure 8)

Statistic Values	Without Learning (days)	With Learning (days)
Mean	403,2	359,8
P10	385,9	342,9
P50	403,2	359,8
P90	420,4	376,7
Standard Deviation	13,4	13,2

Fig.39 presents the aggregated P&A duration for 15 wells on Brage. The means and standard deviations from the "single-well forecast" were used as input to create a normal distributed curve for the sum of the 15 wells. Like expected, and in consistency with the theory, by including the assumption of a learning curve, the PDF curve is shifted to the left. The result from the simulations above reveals the importance of assessing these effects in budget planning and decision-making processes. The mean value decreases from 403.2 days to 359.8 days, while the P10 and P90 values, decreases from 385.9 and 420.4 days to 342.9 and 376.7 days, respectively.

8.3 Total Duration of P&A on Brage

Without Risk

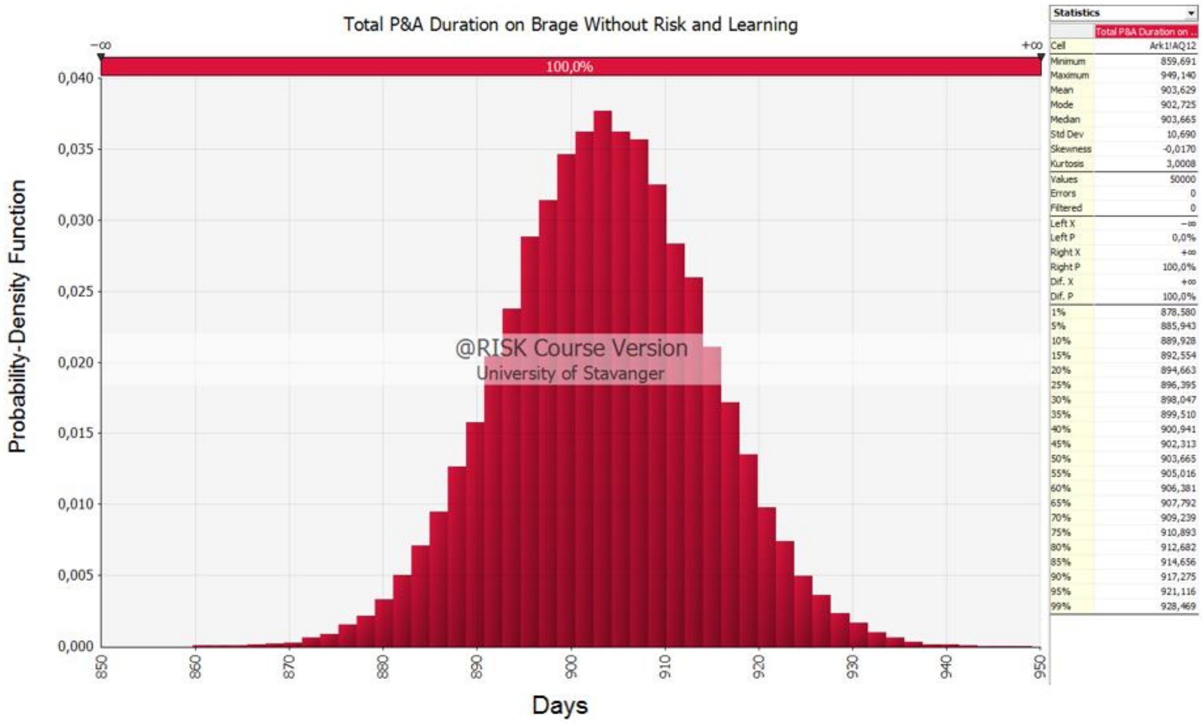

Figure 40: The Probability Density Function for all 40 Wells on Brage Excluding Risk and Learning.

Table 24: Statistic Values for P&A of all 40 Wells on Brage Excluding Risk and Learning

Statistic Values	Without Risk and Learning (days)
Mean	903,6
P10	889,9
P50	903,7
P90	917,3
Standard Deviation	10,7

For the case with neither risk nor learning, the total duration for the 40 wells on Brage has an estimated mean of 904 days. The maximum expected duration is 950 days while the minimum 859 days.

With Risked Events and General NPT

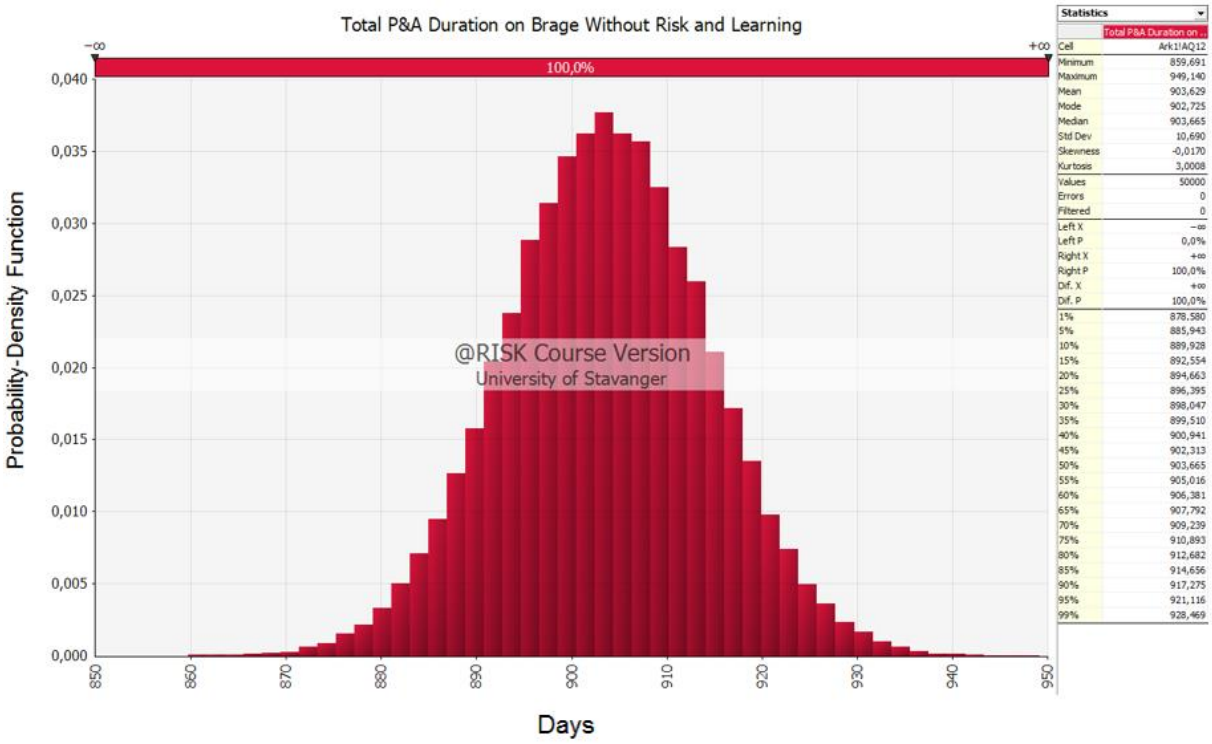

Figure 41: The Probability Density Function for all 40 Wells on Brage With/Without Risk/Learning.

Table 25: Statistic Values for P&A of all 40 Wells on Brage With/without Risk/Learning.

Statistic Values	With Risk and Without Learning (days)
Mean	1044,9
P10	1017,7
P50	1044,9
P90	1072,2
Standard Deviation	21,26

By including risk to the model, the total duration has an estimated mean of 1045 days. This does not consider the effect of learning. We see that the uncertainty is reflected through a higher standard deviation. The expected maximum and minimum duration is 1139 and 952 days respectively.

With Risked Events, General NPT and Learning on Procedure 8 and 9:

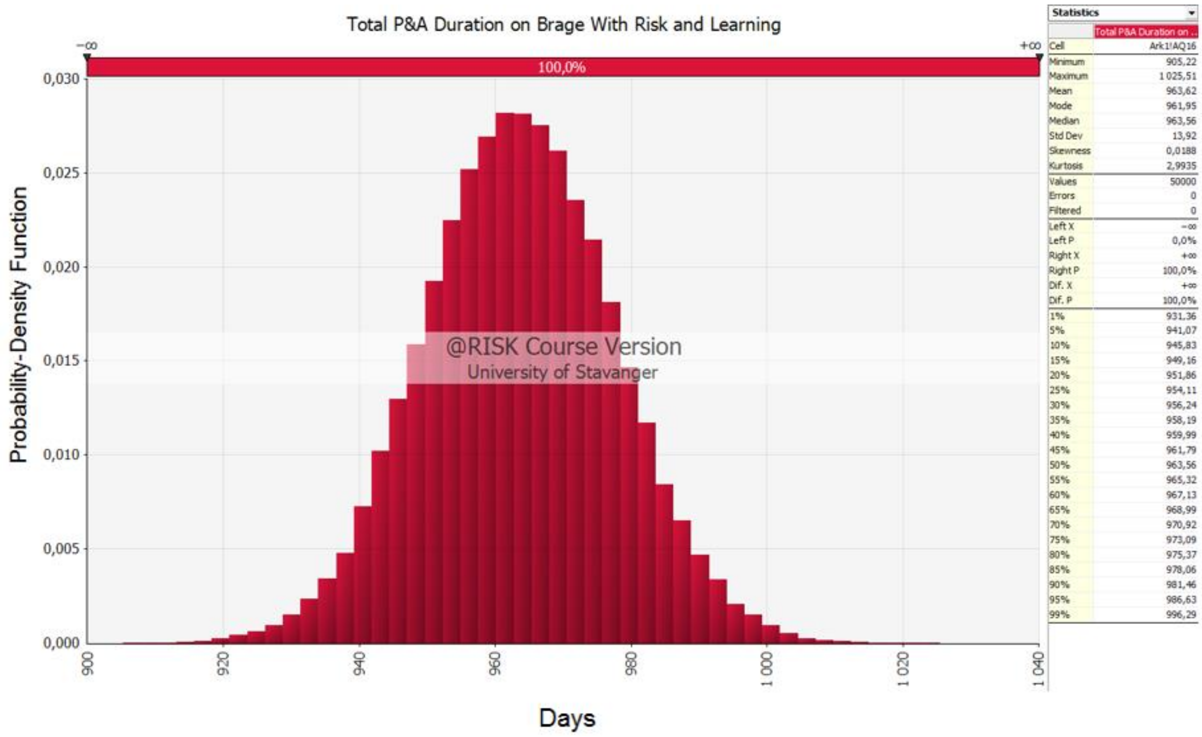

Figure 42: The Probability Density Function for all 40 Wells on Brage Including Risk and Learning.

Table 26: Statistic Values for P&A of all 40 Wells on Brage Including Risk and Learning

Statistic Values	With Risk and Learning (days)
Mean	963,6
P10	945,8
P50	963,6
P90	981,5
Standard Deviation	13,92

When both learning and risk is assumed, the total duration is as expected, less than for the previous estimate. The estimated total duration is 946 days or 2.6 years. We see that the by assuming learning on two of the procedures, i.e. on 22 of the wells, the estimated mean value is reduced by 10 %. If learning also were assumed on the remaining wells, this percentage would have increased even more. From this we see the importance of including learning in our estimates.

9 Discussion and Sensitivity Analysis

The results presented in Chapter 8 and APPENDIX D imply that abandoning the 40 wells on Brage will take 963 days. This estimate assumes learning on Procedure 8 and Procedure 9. For the case with no learning, the estimated duration is 1044 days. However, the estimates are exposed for several assumptions and uncertainties. The uncertainties relate to the input data used, the selected unplanned events and their probability, correlation between wells and sub-operations, the established learning curve parameters and many others. To reduce the potential of errors in the estimation model, thoroughly assessment of these uncertainties is crucial. In addition, by performing sensitivity analysis, potential time drivers could be identified early in the project and enable early assessment of these. This could reveal where resources should be allocated and where alternative methods and modern technology can have the greatest impact.

This chapter aims to discuss some of the assumptions and uncertainties related to the estimation results from Chapter 8. In addition, a sensitivity analysis will be presented through tornado charts to evaluate the time drivers with more ease. The revealed time drivers will then be discussed through potential upsides by using new and more advanced technology.

9.1 Sensitivity Analysis

In this section, the sensitivity of the most critical operation will be presented. Operations exposed to the greatest amount of uncertainty, along with their possible impact on the total duration will be presented through a tornado chart. The tornado chart could be used to easier assess operations that require more attention in the planning phase. This can be related to finding new technology that potentially could reduce duration and uncertainty for these operations. The potential upsides by using modern technology will also be discussed in this section. Regarding the tornado charts, only Procedure 5 will be presented. This procedure contains the most uncertain operations and will also cover the uncertain operations from the other procedures.

Sensitivity Analysis for Procedure 5

Fig.43 below ranks the operations in Procedure 5 based on their possible impact on the total duration's mean. As expected, we see that the operations exposed to the greatest amount of uncertainty are those who have an associated unplanned event. The unplanned event associated with the critical operations are also presented in the same figure.

We see that the logging of 9 5/8" casing in Green Clay interval is assumed to be the most critical operation. This is due to the risk that the logging results indicates poor bonding between the Green Clay and the outer casing. Referring to Chapter 5 section 5.4, the consequences related to a poor Green Clay bonding could be section milling of the outer casing before placing a cement plug. The additional operational step concerning milling is a time-consuming operation and will be a large addition to the original activity of logging the 9 5/8" casing. Fig.43 implies that the risked event related to this activity, can lead to a total duration for Procedure 5 of 42.5 days, compared to the baseline of 35.45 days.

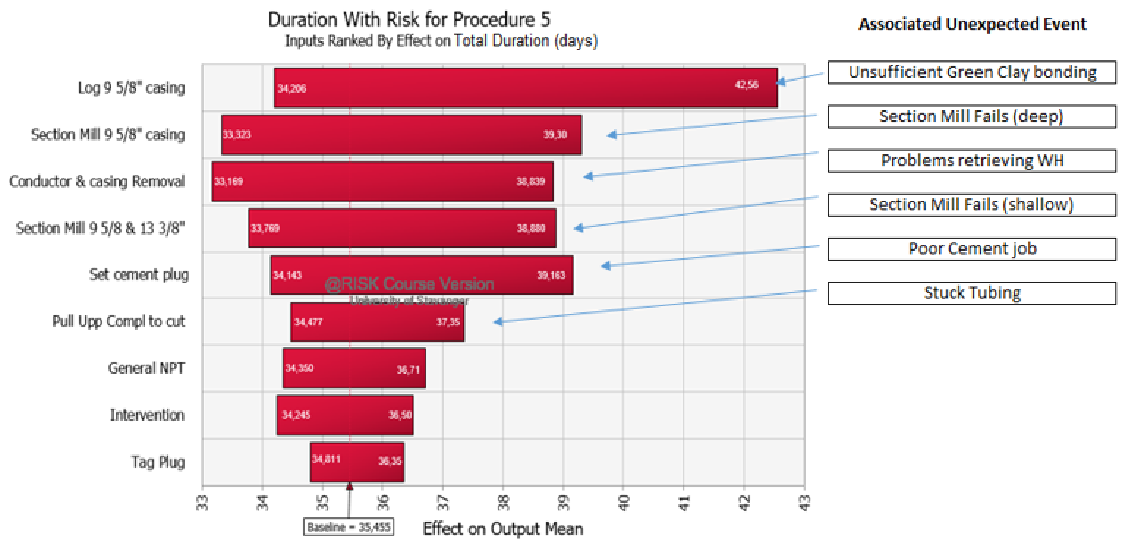

Figure 43: Tornado Chart Ranking the Most Critical Well Operations on Brage

The 2[th] and 4[th] most uncertain operation is related to the original planned section milling of the 9 5/8" and 13 3/8" casing. These operations are associated with the unplanned event where the section milling fails. As mentioned, section milling is a very time-consuming operation and can therefore have a significant impact on the total duration.

The final operational step in the P&A process is the removal of conductor and internal casing a few meters below seabed. This process consists of several cut and retrieval activities that will be subject to uncertainty. The risks may relate to the age and condition of the casing strings and the fact that several cut and retrieval steps are required. This step is ranked as number three in terms of effect on total duration mean.

The critical operations concerning section milling, either the originally planned activity or when serving as the solution to the insufficient Green Clay bonding, could benefit from technology that is evolving these days. Section milling is performed to enable the cement plug to extend across the entire wellbore and thereby seal in vertical and horizontal directions. Moreover, milling can, as mentioned in Chapter 2, cause several problems. These problems are mainly due to the generated swarf. Today, service companies see immense potential in research and development (R&D) related to P&A. Both improved milling technology and alternative methods are now evolving in the market. Two technologies will be presented in the following.

Upwards Milling – SwarfPak by West Group

The principle behind the SwarfPak tool by West Group [40] is to section mill upwards and thereby leave the swarf downhole instead of bringing it up back to surface. Leaving the swarf downhole could be a huge time saver in relation to the logistical and environmental challenges with swarf handling, swarf clustering in the BOP and so on. Another technical goal for the SwarfPak is to reduce vibrations, which may reduce the fast wearing of the knives/cutters enabling the tool to mill 50 m in one run [40]. This method could potentially reduce a lot of the uncertainties associated with milling operations and contribute to reduce the overall duration and costs of P&A. The SwarfPak has been awarded with several awards, but information regarding commercialization has not been obtained during this thesis [40].

PWC technology – Provided by HydraWell

As explained in Section 2.6.2, the PWC technology is an alternative to the combination of section milling and placing a cement plug. The principle of PWC is to perforate the casing, wash the annulus through the perforation and squeeze cement through the perforation and into the annulus [20]. The method is normally conducted when the cement/formation behind the outer casing is lacking sufficient bonding properties. By avoiding the conventional milling method, the PWC technology may contribute to reduce the duration of placing a cement plug.

For the case on Brage, section milling is suggested on five wells, whereof one requires section milling at two different depths. Each of the five wells require a dual milling operation where both the 9 5/8” and 13 3/8” casing is milled to place the environmental plug. This can either be performed in one or two runs. This operation is naturally a time-driver and the benefits from innovative technology can be large.

HydraWell is a well integrity specialist company that provides services in the P&A and slot-recovery market. HydraWell provides two systems, HydraHemera and HydraKratos, which enable PWC technology to be applicable for multiple casings and annuli [20]. The operation starts with running the HydraKratos system. This consists of a perforation tool and a casing expander. The energy from the explosion will perforate the two casing strings, and ensure expansion of the casing strings below the perforation interval. This expansion establishes a foundation for the coming annular cement barrier. The HydraHemera system is then run. This system consists of jetting tool, a cementing tool and an Archimedes tool. The jetting tool ensures proper cleaning of old mud and debris in the annuli, while the cementing tool squeezes the cement through the perforation. The Archimedes Cementing tool ensures proper displacement of the cement [20]. The operations of the HydraKratos and HydraHemera is summarized in Fig.44 below.

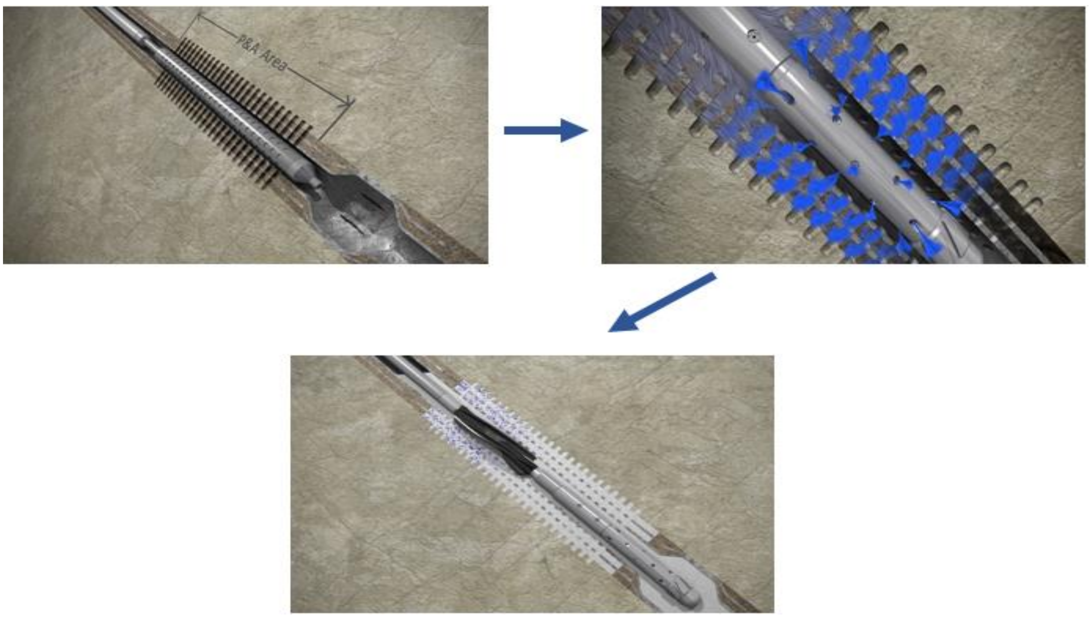

Figure 44: Decription of the PWC System, HydraHemera, Provided by HydraWell [20]

The benefits from avoiding dual section milling on Brage may be considerable. One of the case stories from HydraWell showed how their PWC technology reduced the duration of placing barrier plugs on a platform in the North Sea. On the considered field, there had previously been performed section milling to remediate the dual casing annulus. Together with the cement job, this process took up to 80 days to complete. Using the HydraHemera system, HydraWell lowered the duration of placing the primary and secondary barrier plugs to 3 days [41].

Even though the technology seems promising, there may be issues related to verification of the barrier. For the plug to be valid as a barrier in accordance with NORSOK, the cement bonding in both annuli must be verified [4]. One method for verification is logging. Nevertheless, due to limitations of logging through multiple casings, the verification of the cement bonding in dual annulus is difficult. According to a presentation held by HydraWell at the Plug and Abandonment Seminar in 2017 [42], a solution to this problem is under process. Verification by pressure testing could potentially serve as a solution [18].

The difficulties related to logging through multiple casing strings will cause issues if the cement plug is planned to function as both primary and secondary barrier plug. If this is the case, the casing cement *shall*, according to NORSOK, be verified by logging [4]. Thus, the HydraHemera will not be applicable with the available logging technology. However, as mentioned in section 2.5, Equinor Energy AS is working on developing a method for logging through two casings [18]. In addition, since the production on Brage is estimated to last until 2030, technology providing logging through multiple casings is not necessarily a too futuristic goal.

Relating the PWC technology provided by HydraWell to the Brage case, running the HydraHemera may provide a reduction in plugging duration and operation uncertainties on the 5 wells where section milling is proposed. The milling operations proposed on these wells are performed to place the environmental plug that extends across the entire wellbore. Since the requirements for the environmental plug is different than for the primary and secondary plugs isolating the reservoir, logging is not required. Hence, the plug can be verified by pressure testing and the HydraHemera system can therefore be applied.

For A-6, section milling in the Green Clay interval before placing the primary and secondary barrier plug serves as the proposed P&A solution in this thesis. Here, logging is required for two reasons: the formation will act as external WBE, and the internal WBE will be one plug that acts as primary and secondary barrier. According to NORSOK, logging of the external

WBE *shall* be performed if one of these two arguments are true [4]. Hence, section milling will, with current available technology, be the best approach for placing the primary and secondary barrier plug on A-6.

Conducting Phase 3 of the abandoning process using SABRE™ system by Claxton

The operation ranked as number three in the tornado chart illustrated in Fig.43, relates to Phase 3 of the abandoning process. This phase involves cutting and retrieval of the conductor and the internal casings. The input data used for Phase 3 in this thesis were based on the abandoning project on Murchison. The tubulars on Murchison were cut and retrieved separately [39]. Even though the tubulars are retrieved from shallow depths, performing several cut and retrieval operations will be exposed to risk and uncertainties.

On Brage, the estimated duration for Phase 3 may be reduced by implementing modern technology. The cutting system provided by Claxton, explained in section 2.6.3, enable several tubulars to be cut and retrieved at once. The cutting system can enter wells down to 6 5/8" and simultaneously recover 30" conductor and all internal tubulars. This cut and retrieval process is regardless of the casing eccentricity and cement behind the tubulars [21]. By applying this methodology to the future Brage abandonment, the duration of Phase 3 may be reduced. A case story from Claxton showed how one operator reduced the overall operation by 50 % compared to the conventional method [43].

9.1 Uncertainty Related to the Selected Unplanned Events and Operations Input Data

"We are prone to overestimate how much we understand about the world and to underestimate the role of chance in events."

- ***Daniel Kahneman, Thinking, Fast and Slow [44, p.14-15]***

The initial quote by Daniel Kahneman emphasis the importance of thoroughly assessment of the potential risks. For the probabilistic approach, there are no rules in terms of which event to be considered, implying that the selection of events is a decision made by the party concerned [24]. It should be noted that the selected event will not cover all possible events as the presence of unknown unknowns is avoidable [24]. However, ignoring several events could lead to systematic underestimation and thereby less valid estimate. This section aims to discuss the selected risked events, along with the uncertainty in duration and probability of occurrence for these events.

Uncertainty Related to the Selected Unplanned Events

The selection of unplanned event for this this thesis was based on historical incidents and expert opinions. Regarding the historical incidents, these were collected from incident recorded on slot recovery activities on Brage. A complete abandonment has not yet been performed at Brage and hence, the historical incidents does not reflect the entire P&A process. Thus, expert opinions were needed to further evaluate the events of interest. The event of stuck tubing where the one collected from the historical records. This event has occurred frequently on Brage, and especially for the wells with an old type of ASV installed. The other events were based on suggestions from drilling engineers at Wintershall [38].

As mentioned initially, it is not possible to cover every risked event in the model developed in this thesis. There will always be unknown unknowns. David Hillson [45] present four reasons for why it is difficult to identify all risks in advance:

1) Some risks are **inherently unknowable.** These events are the true unknowns, often referred to as Black Swans, and will occur as a surprise with an unknown consequence.
2) Some risks will be **time-dependent,** i.e. these risks emerge with time. However, the identification of risks is bounded by a time frame, and some uncertainties may lay beyond this time frame. These events may not be possible to identify until they are within the identification time window.
3) Some risks will be **progress-dependent**. The risk may not be visible until progress has occurred. Hillson [45] refer to an example where a risk is present at the back of a certain building. If we fail to walk around the building for investigation of the other side, this risk will not be identified.
4) The last category of hidden risk relates to the **response-dependent** risks. These risks will only appear when measures are conducted to mitigate an already identified risk [45].

The four groups above clarify that identification of every risked event is impossible. This especially applies to the inherently unknowable**.** Hillson states that; *"Risk identification should aim to identify **all knowable risks at this point in time,** recognizing that some risks are currently hidden from sight* [45]." He adds that the risk assessment must be repeated to identify new risks, e.g. when risks emerges with time, occurred progress and response made to previously identified risks [45]. By ignoring the risks, either unintentionally or intentionally, the model may systematic underestimate the duration. This emphasis the importance of proper risk assessment.

In addition, risk assessment is substantial for the P&A performance and to ensure safety when the different well activities are performed. However, the level of detail of the risk assessment must be evaluated by the party concerned. More thoroughly risk assessment may be required for HSE related questions and in the operation planning, compared to what's needed for a time estimation.

For simplicity, the events considered in this thesis were at a lower detailed level. The considered events were based on major incidents recorded on Brage, and other likely major events associated with certain operations. To capture other smaller risks and non-productive time, the general NPT events were aggregated and expressed through a percentage of total productive time. Regarding the hidden risks explained through David Hillson above, the time estimates obtained in this thesis are exposed to more uncertainty than what's reflected through the selected unplanned events. This is something that needs to be kept in mind and evaluated before further decision making.

Uncertainty in Duration and Probability of Occurrence of the Unplanned Events

After selecting which unplanned event to consider, their likely duration and probability of occurrence must be defined. Like for the other input data used, the duration selected for an unplanned event is reflected through a triangular distribution. This distribution aims to cover a greater range of probable outcome and thereby express the uncertainty in the duration outcome. However, the triangular distribution is based on three selected values, where the selection of these values will be exposed to uncertainty. It is important to keep in mind the pitfalls presented in Chapter 3. If the triangular input values are based on historical data, we should not draw the assumption that the fastest and slowest performances possible, are represented by the minimum and maximum values in this data set [25].

As only one of the unplanned events is based on historical duration data, the duration of the remaining events was assessed together with drilling engineers at Wintershall. Consequently, the selected input values for the remaining events will be exposed to uncertainty. As mentioned in Chapter 6, Akins et al. states that experts tend to be biased due to negative or positive experience with a certain operation or event. Experts may also be overly confident in their capability in assessing uncertainty. Akins emphasis the importance of involving as many experts as possible in the assessment [24]. Due to the small number of experts involved in this thesis, the presence of uncertainty is avoidable. However, since a triangular distribution has been used, a lot of the uncertainty is still captured.

Regarding the probabilities of the unplanned events to occur, these were also based on expert opinions. The general NPT percentage were however based on historical data and evaluated together with the drilling engineers. The elements described above concerning the expert opinions, will therefore also be applicable for the case of probability uncertainty. The events with an assumed probability of less than 10 %, were intentionally not included. A decision was made to draw greater attention to the events with higher risk, i.e. the events with higher probability and more profound consequences.

The uncertain elements concerning expert opinions and selection of triangular input values, will also be applicable to the input data used for the *planned* operations. In addition, uncertainty related to comparability may have a greater impact on the validity of the estimates concerning planned operation than for the unplanned events. To reduce this uncertainty, it is important that the historical duration data used, is adjusted to be applicable for the considered well [24]. This relates to the given well situation such as; wellbore properties, fluids present, inclination of the wellbore, top of cement, exact placement of cement plug and so on. This is a time-consuming process and beyond the scope and available time for this thesis. However, the data used were adjusted for differences in depths. E.g. the time to place a cement plug at 600 m will be less than the time to install it at 2500 m. This is once again a question on level of details. Involving more details does not necessarily equal more accurate estimates, and can in some cases lead to the very opposite [24]. The depth of investigation of the input data and the considered well is a cost/benefit question and should be evaluated to best cover the objective of the given estimation model.

9.3 Uncertainty Related to the Effect of Learning

Uncertainty in Learning Curve Parameters

The parameters expressing the learning curve were defined in Chapter 3. To recap, the C parameters is defined in the following way [30]:

- ***C_1*** – *"a constant reflecting how much longer the initial well takes to drill than the idealized final well"* [30, p. 3].
- ***C_2*** – ***"****a constant reflecting the speed with which the drilling organization reaches the minimum drilling time for an area"* [30, p. 3].
- ***C_3***– *"constant that reflects the idealized minimum drilling time for an area"* [30, p. 3]. I.e. the technical limit.

As the C_1 value normally is found by subtracting the C_3 value from the first well duration, it is clear that the values worthwhile describing further are C_3 and C_2.

Uncertainty in the C_1 value:

The value of C_3 can be based on historical data or expert opinion. Depending on how certain the estimator is on the value, it can be determined in a deterministic or probabilistic manner [28]. For this thesis, the C_3 value were set equal to the P10 value obtained from the simulation of a single well category. This value will, together with the C_2 value, be given when the simulation is conducted, i.e. a deterministic approach is used. However, as the P10 value is an estimated value, based on uncertain underlying input data, it will naturally be exposed to some uncertainty. Therefore, we may expect the true value of C_3 to be either greater or less than the obtained P10 value. It is difficult to avoid these uncertainties, but they may however be reduced by thorough assessment of the applied input data.

The technical limit may also vary when modern technology is available. By using more efficient technology, the technical limit is likely to be reduced compared to the case when older technology is applied. This is also a factor that needs to be considered when performing the estimation.

Keeping the factors described above in mind, there will be uncertainties also when the deterministic approach is used. Nevertheless, the deterministic method was applied in this thesis for simplicity reasons. In cases were the estimator is more uncertain about the C_3 value, the value could be determined in a probabilistic manner. The C_3 value is then simulated through, for instance, a triangular distribution [28].

Uncertainty in the C_2 value:

The C_2 value, representing the speed of learning for an organization, will also be exposed to uncertainty. Is it a fair assumption that the industry standard reflecting the learning in drilling operations, also is applicable for P&A operations? A C_2 value of 0.34 were proposed as an industry standard by Brett and Millheim in their report from 1986 [30]. How relevant is this value today, 32 years later? Even though this value has been used in other estimates in recent studies [17], it might be likely that this value has changed over the years.

The duration data from Murchison implied a C_2 value of 0.18, which is far less than the standard. However, as mentioned in Chapter 6, this value may be affected by the fact that the wells considered on Murchison were not categorized and thereby prevents good assessment of the true learning. Other factors that can impair the comparability in learning between the Murchison field and Brage is related to the fact that Murchison is located at UK sector. This may relate to the employee’s offshore schedule which will change the efficiency of learning transfer. If one employee has an off-duty period of 4 weeks, he might risk waiting several months before he performs the same type of operation again. Consequently, if the transfer of learning is poor within the drilling company, this off-duty period may impair the effect of learning for certain well activities. Employees working on UK sector are known to have more frequent trips offshore due to a 2-2 or 2-3 schedule. This may lead to more continuity and potentially positive impact on the learning efficiency.

Another factor that may alter the C_2 value is related to how well the P&A project is planned in advance. If the project is well planned, i.e. several P&A approaches has been discussed, the different operations has been evaluated to improve efficiency, lessons learned from previous operations has been implemented etc., the rate of learning may be reduced. Contrary, if the project is lacking good planning, we may assume that learning will have a greater impact on the duration of the different P&A activities.

Based on the uncertainties presented above, it is important to be aware of which factors that will change the C parameters and to perform thorough assessment of these factors. From Fig.45

and Fig.46, it is clear how different values of C_2 and C_3 will change the PDF curves, and hence, change our duration estimates.

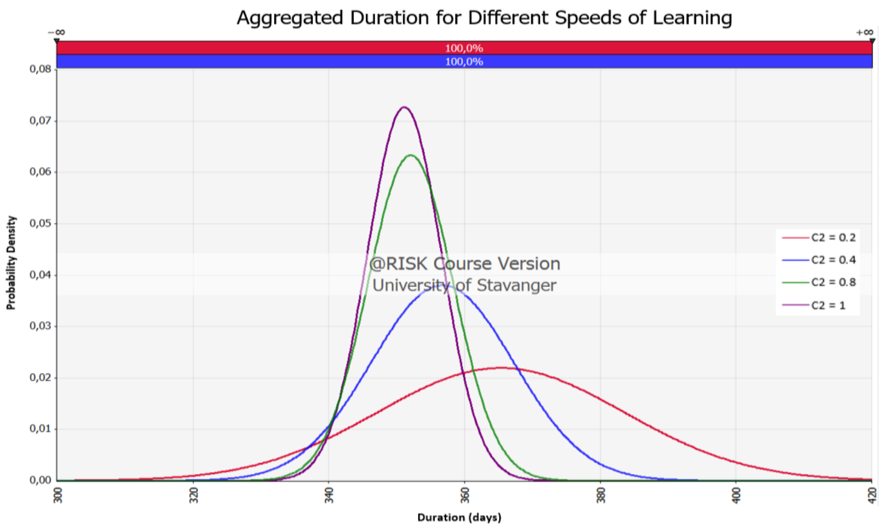

Figure 45: Probability Density Function for Different Values of Speed of Learning

Fig.45 shows the aggregated duration for 15 wells on Brage, when the speed of learning, the C_2 value, varies from 0.2 to 1. As expected, the estimated duration decreases as the speed of learning increases. Greater C_2 value implies that the company will quickly implement the lessons learned from previous experience to the succeeding operations [30]. Another thing to notice is that the curve will be narrower for the higher values of C_2.

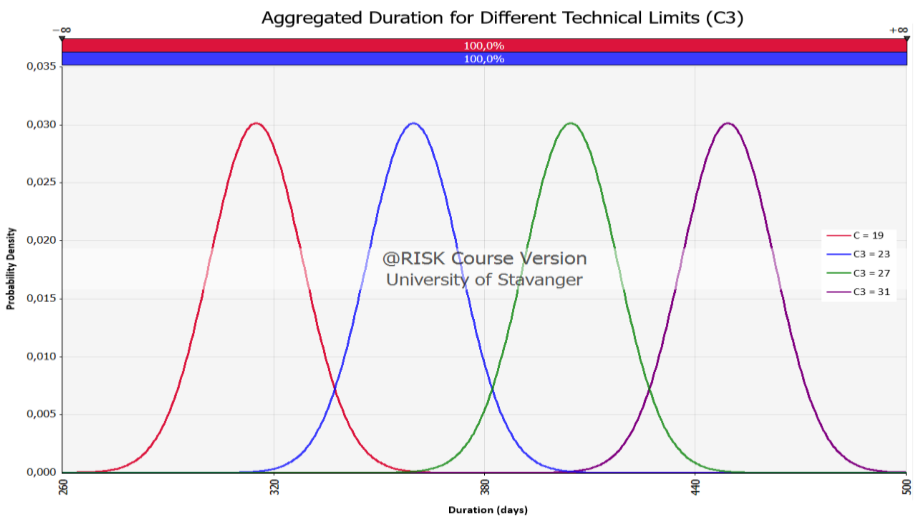

Figure 46: Probability Density Function for Different Values of Technical Limit (C_3)

Fig.46 shows the PDF curves for the same 15 wells for technical limits (C_3) of 19, 23, 27 and 31 days. We see that for higher technical limits, the curves shift to the right towards higher durations. However, their shape will remain constant. This is a logical response, as changes in C_3 value, only changes the limit the duration moves towards.

Other Uncertainty Factors Related to the Effect of Learning

In addition to the factors related to the learning curve parameters, there are several aspects the estimator must keep in mind when incorporating the effect of learning to the estimation model. The thesis assumes that a greater amount of repetitive and similar operations must be conducted to obtain a substantial effect of the learning. For simplicity, the effect of learning was assumed to only have an impact on two of the twelve procedures. Procedure 8 and 9 are applicable for respectively 15 and 7 wells and are the two procedures concerning most of the wells on Brage. However, as learning could in theory be expected for the subsequent 39 wells, this is a simplification. Some of the well operations will be identical, or at least similar, in all 12 procedures and hence, we could assume the effect of learning to have an impact on more than the 22 wells considered in this thesis. By allowing the model to evaluate the learning for all wells, the total P&A duration will naturally decrease. Whether the learning should be implemented to concern more of the wells is something that needs to be assessed for the given project.

As mentioned initially in Chapter 3, the amount of time to implement the learning will affect the impact of learning to the total P&A duration [28]. If the time frame of the project is too narrow, this may impair the learning transfer due to reduced maturation time of the experiences gained. This problem could to some extent be avoided if good procedures for implementing the lesson learnt are established. This could for instance be to establish a procedure to capture the learning in parallel to the ongoing operations. Another approach is to complete a certain number of wells, before a period with maturation and assessment of the experiences gained from the first wells is commenced. The latter approach must be evaluated to reveal the potential benefits of postponing the operations compared to completing all wells in one.

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10 Conclusion and Recommendation for Further Research

10.1 Conclusion

This thesis has been a part of the preliminary assessment of P&A on the Brage field. The questions raised initially were:

- How do we develop a probabilistic estimation model that include both learning and unplanned events?
- What is the estimated duration of P&A of the wells on Brage?
- How will the inclusion of uncertainties and learning affect the time estimate?
- Which operations are exposed to most uncertainty and thus, should be given sound effort in the future?
- Which operations could benefit from innovative technology?

The wells on Brage have been categorized and operational procedures have been established in accordance with standards and regulations on the NCS. The categorization and operational procedures have been based on a previously conducted master thesis regarding P&A on Brage [34], and adjusted by further evaluations of the Final Well Reports from Wintershall's data base [32]. The operational procedures have also been assessed together with drilling engineers at Wintershall.

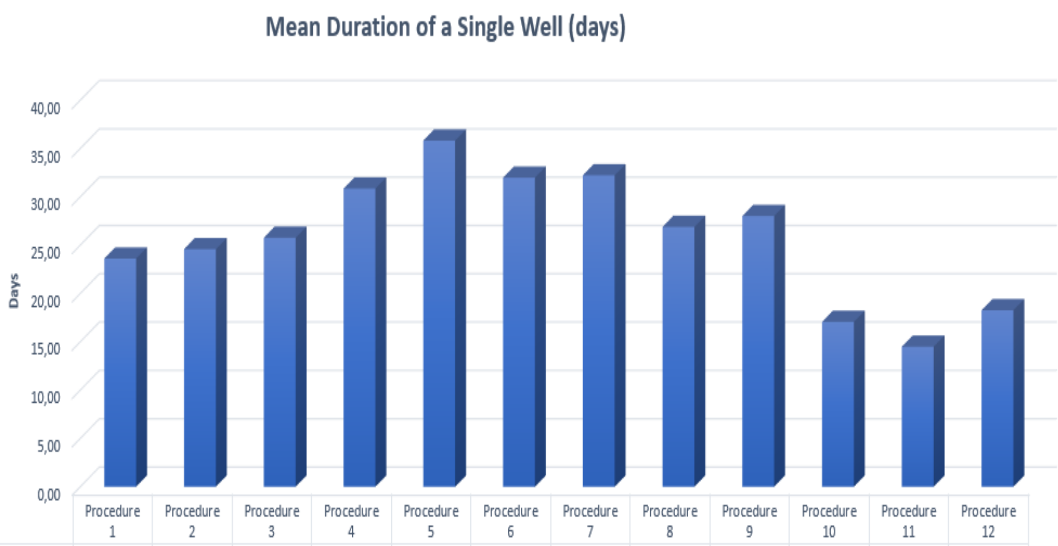
The 40 wells on Brage can roughly be divided into four categories: (1) Simplified Casing Design, (2) Pre-Drilled Wells, (3) Wells with a Production Liner and Tie-back Casing, and (4) Water Producers and Injectors. A more detailed categorization has also been introduced. This categorization was based on distinct features of the wells and was performed to establish more comprehensive operational procedures. This lead to 12 procedures that covers the required P&A operations for the 40 wells on Brage.

Further, three probabilistic time estimation models were established in accordance with estimation theory. The first model, the base case, excluded the effect of risked event and learning. The second model was made to evaluate the effect of including uncertainties related to unplanned events and general NPT. The third model was an extension of the second model to include the improving effects of learning.

The inclusion of learning was based on learning curve theory and the Brett and Millheim method [28] [30]. A learning curve for the abandonment of the Murchison field was established to express the potential of learning on a project comparable to the Brage case. The value reflecting the speed of learning was set to the average between the value obtained from the Murchison learning curve and the industry standard suggested by Brett and Millheim [30]. Table 27 below emphasis the importance of including learning into the model through the obtained differences in time estimates.

The resulting effect were consistent with the theory described in Chapter 3. I.e. including unplanned events and general NPT shifted the PDF curve towards higher duration, lead to more uncertainties reflected through a higher standard deviation and a PDF curve with more skewness. The effect of including learning were a shift in the PDF curve towards lower durations. Thus, neglecting these factors can lead to errors in the estimate, both in terms of underestimation and overestimation.

Fig.47 below presents the mean duration of all 12 procedures. Procedure 5 is predicted to be the most time-consuming procedure. This procedure relates to the Pre-Drilled Well where section milling is required at two different depths. Procedure 11 is predicted to be the least time-consuming procedure. This procedure relates to the Utsira Water Producers and involves the least operational steps.



	Procedure 1	Procedure 2	Procedure 3	Procedure 4	Procedure 5	Procedure 6	Procedure 7	Procedure 8	Procedure 9	Procedure 10	Procedure 11	Procedure 12
Mean Duration Single Well (days)	23,61	24,58	25,76	30,85	35,82	31,98	32,22	26,88	28,01	17,06	14,49	18,26

Figure 47: The Estimated Mean Duration for all Procedures.

Table 27 below presents the estimated duration for abandonment of the 40 wells on Brage. The results imply a mean duration of 963.6 days. This estimate assumes learning only on Procedure 8 and Procedure 9, which concern 15 and 7 wells respectively. For the case with no learning, the estimated duration were 1044 days. This estimate reveals the large potential in learning and emphasis the importance of optimizing the operational procedures and implementing lesson learned throughout the project.

Table 27: Statistic Values for the P&A Duration of the 40 Wells on Brage.

Statistic Values	With Risk and Learning (days)	With Risk and w/o Learning (days)
Mean	963,6	1044,9
P10	945,8	1017,7
P50	963,6	1044,9
P90	981,5	1072,2
Standard Deviation	13,92	21,26

The most critical operations were identified through the tornado chart in Fig.43. The activities subject to most uncertainty relates to insufficient bonding in the Green Clay interval, section milling and retrieval of conductors and internal casings. With that in mind, these operations should be assessed early to identify alternative approaches or potential benefits from using innovative technology. The alternatives proposed in this thesis includes the PWC technology from HydraWell [20], upwards section milling provided by West Group [40] and the abrasive cutting tool provided by Claxton [21]. Applying these, or similar technologies, may cause less uncertainty and a reduction in total P&A duration.

10.2 Recommendation for Further Research

Including the effect of learning on several wells and more thoroughly evaluation of the speed of learning (C_2-value)

The estimate obtained in this thesis assumed learning on 22 of the wells on Brage. To obtain more accurate time estimates, learning should be included to reflect the improvements from the first to the last well P&A'd, i.e. learning should be assumed on 39 of the wells. For future time estimation, this could be feasible by first investigating the wells where similar sub-operations are applicable. By further develop the estimation model based on this, the aggregated duration estimate could reflect learning on each repetitive sub-operation.

Another element to consider is related to the speed of learning. The industry standard value is 0.34. However, this value is dated back to 1986 and thus, its validity can be questioned. The adequacy of the value obtained from the Murchison field can also be questioned (refer to Section 9.3). Thus, by performing thoroughly assessment of this value, more accurate duration estimates may be obtained. One suggestion is to determine a distinct learning curve for Brage. The learning curve could be based on P&A activities already conducted during re-entries on Brage, instead of being based on the learnings present on other fields.

Include Correlation in the Estimation Model

The Monte Carlo simulations performed in this thesis treats each sub-operation as individual and thus, non-correlated. However, correlation may be expected to a certain extent. If the tubulars are in poor condition, problems may be encountered for several of the tubular related operations. E.g. if the retrieval of casing from deep is exposed to problems, this problem may also be encountered when the casings are retrieved from shallow depths. If there are issues related to section milling deep, section milling shallow may also be exposed to the same issues. These are only two examples and the dependencies between different sub-operations should be evaluated for the considered project.

Correlation between several wells may also be present. If the logging results indicates poor bonding to casing for one of the wells, the likelihood of having insufficient bonding in subsequent wells may be greater. If the condition of one of the wells is poor, is it likely that a similar well will have the same issues? Not necessarily, but the possibilities should however be evaluated.

Ignoring the effect of correlation may cause errors in the estimates, and hence, they should be dealt with. However, correlation may be difficult to assess when the amount of sub-operations is big or when a multi-well campaign is considered [25]. A solution to this could however be to increase the number of contingencies in the estimate.

Digitalization for better assessment of historical data

During this thesis, a great amount of time was dedicated to collect and sort historical operation data. This is a time-consuming process and can potentially increase the threshold for engineers to perform thorough estimation. With the increasing focus on digitalization in the industry, along with the computer's ability to handle large amount of data, the valuable historical data could be extracted and sorted with ease. The sorted data could then be applied for forecasting models in a less time-consuming way. The estimation process may even be automated with the technology evolving today. In addition to simplify tasks related to estimation and prediction, the ongoing digitalization in the industry may have an impact on several other areas in the drilling industry. This emphasis the importance of keeping up with the ongoing "digital revolution."

Other topics that should be evaluated before commencing the P&A project:

- **Batching Operations –** Will it be beneficial to batch certain operations? For instance, the intervention phase could be conducted for all wells before the following well operations are performed. Another option is to perform Phase 3 in batches, e.g. using the system provided by Claxton.
- **Evaluate Rig-Less Activities –** The Sabre cutting system provided by Claxton is conducted without the use of a rig. Using this technology may reduce the total duration related to Phase 3. Conducting certain P&A activities using wireline or coiled tubing could also be a rig-less solution that may reduce the overall duration and should therefore be evaluated.
- **Determine the sequence of wells to be P&A'ed –** Based on the results provided by this thesis, regarding most time-consuming procedure and the operations exposed to most uncertainty, the sequence of abandoning the wells could be determined. It may for instance be beneficial to start with the wells that are believed to be less complicated. This may provide a better start and enable "practice" before the more complicated wells are encountered.
- **In-depth investigation of each well –** Conducting more thoroughly assessment of each well situation can be beneficial. This can be in terms of historical records regarding casing cement, specific depth consideration, calculation of optimum setting interval of cement plugs and so on.

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APPENDICES

APPENDIX A Relevant Well Barrier Criteria from NORSOK D-010

4.2.3.2 Well barrier selection and construction principles

The well barriers shall be designed, selected and constructed with capability to:

a) withstand the maximum differential pressure and temperature it may become exposed to (taking into account depletion or injection regimes in adjacent wells);
b) be pressure tested, function tested or verified by other methods;
c) ensure that no single failure of a well barrier or WBE can lead to uncontrolled flow of wellbore fluids or gases to the external environment;
d) re-establish a lost well barrier or establish another alternative well barrier;
e) operate competently and withstand the environment for which it may be exposed to over time;
f) determine the physical position/location and integrity status at all times when such monitoring is possible; and
g) be independent of each other and avoid having common WBEs to the extent possible.

During operations the following apply:

h) The double block and bleed principle shall be fulfilled for all equipment above seabed/surface, which can be exposed to well pressure, i.e. two valves in series in all in-/outlets from the well.
i) When a workstring penetrates the well barrier, one of the WBEs should be able to shear the workstring and seal the wellbore after having sheared the string.
j) All non-shearable components in the work-string shall be identified.
k) When running non-shearable components through the BOP, there shall be procedures in place for handling a well control situation.
l) When running long non-shearable assemblies, there shall be an element (e.g. annular preventer) installed that can seal the wellbore against any size assembly that penetrates the well barrier.

Figure 48: Well Barrier Requirements, Selection and Construction Principles [4]

15.52 Table 52 – Creeping formation

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

Figure 49: Acceptance Criteria for Creeping Formation [4]

APPENDIX B Procedures and Associated Well-Design

The procedures established for the P&A campaign on Brage. An example of a well related to the considered Procedure will also be presented. The well designs are based on the previously conducted master thesis related to P&A on Brage [34]. However, some minor adjustments and updates have been made by the author of this thesis.

Table 28: Operational Procedure 1

Procedure 1	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Log 9 5/8" casing in Green Clay Interval
8	Set 9 5/8" Mechanical Plug as Base
9	Set Primary and Secondary barrier plugs
10	Tag/dress-off Plug
11	Nipple down BOP
12	N/D tubing Head
13	N/U BOP
14	Cut and Retrieve 9 5/8" casing shallow
15	Set 18 5/8" mechanical plug as base and pressure test
16	Set Environmental plug
17	Tag Plug
18	Remove Conductor and Casing Strings 5 m below seabed

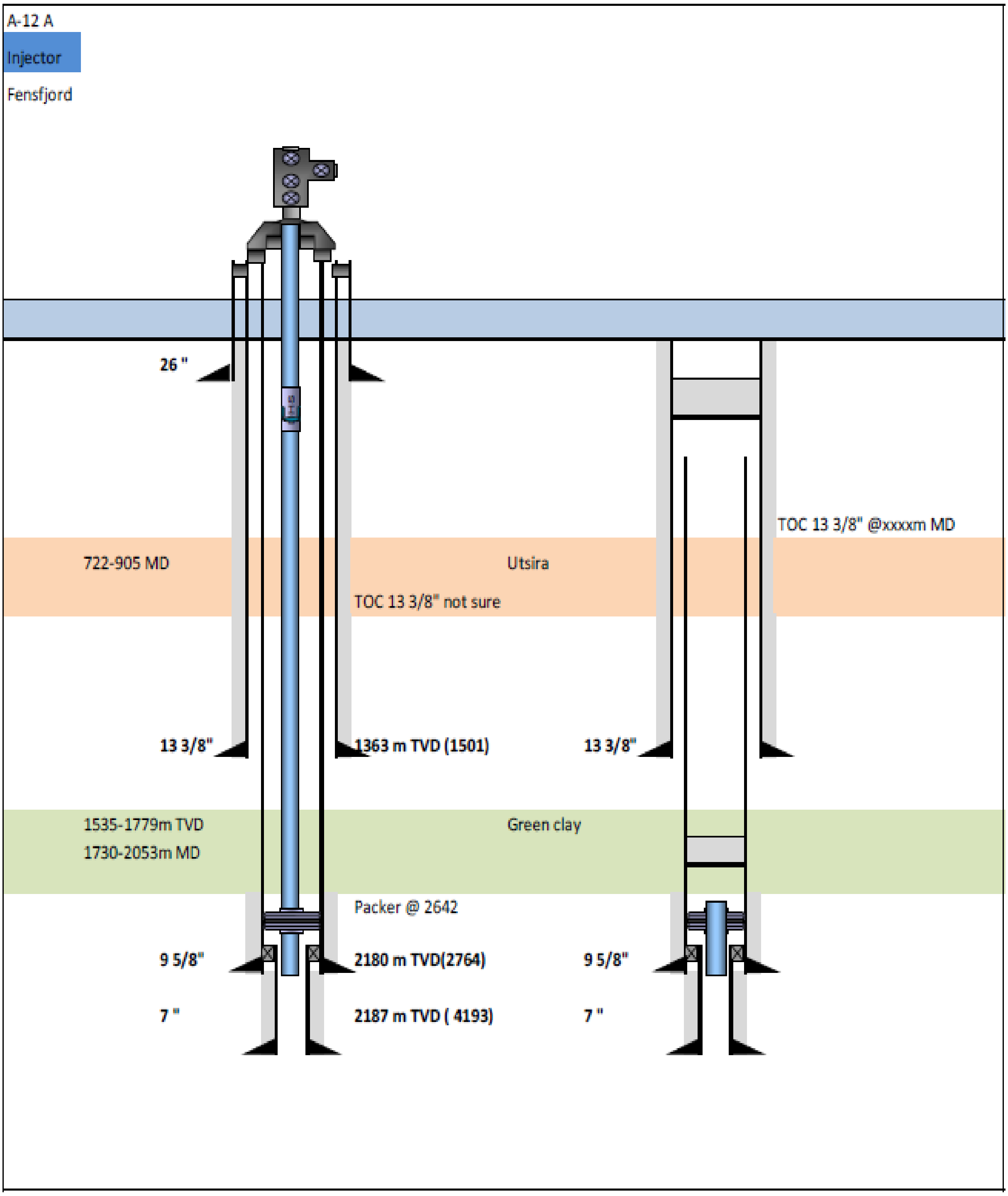

Figure 50: Well Design Associated with Procedure 1 [34]

Table 29: Operational Procedure 2

Procedure 2	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Tubing down to cut between DHSV and FLX
7	Retrieve CTA
8	Pull Upper Completion down to cut
9	Log 9 5/8" casing in Green Clay Interval
10	Set 9 5/8" Mechanical Plug as Base
11	Set Primary and Secondary barrier plugs
12	Tag/dress-off Plug
13	Nipple down BOP
14	N/D tubing Head
15	N/U BOP
16	Cut and Retrieve 9 5/8" casing shallow
17	Set 18 5/8" mechanical plug as base and pressure test
18	Set Environmental plug
19	Tag Plug
20	Remove Conductor and Casing Strings 5 m below seabed

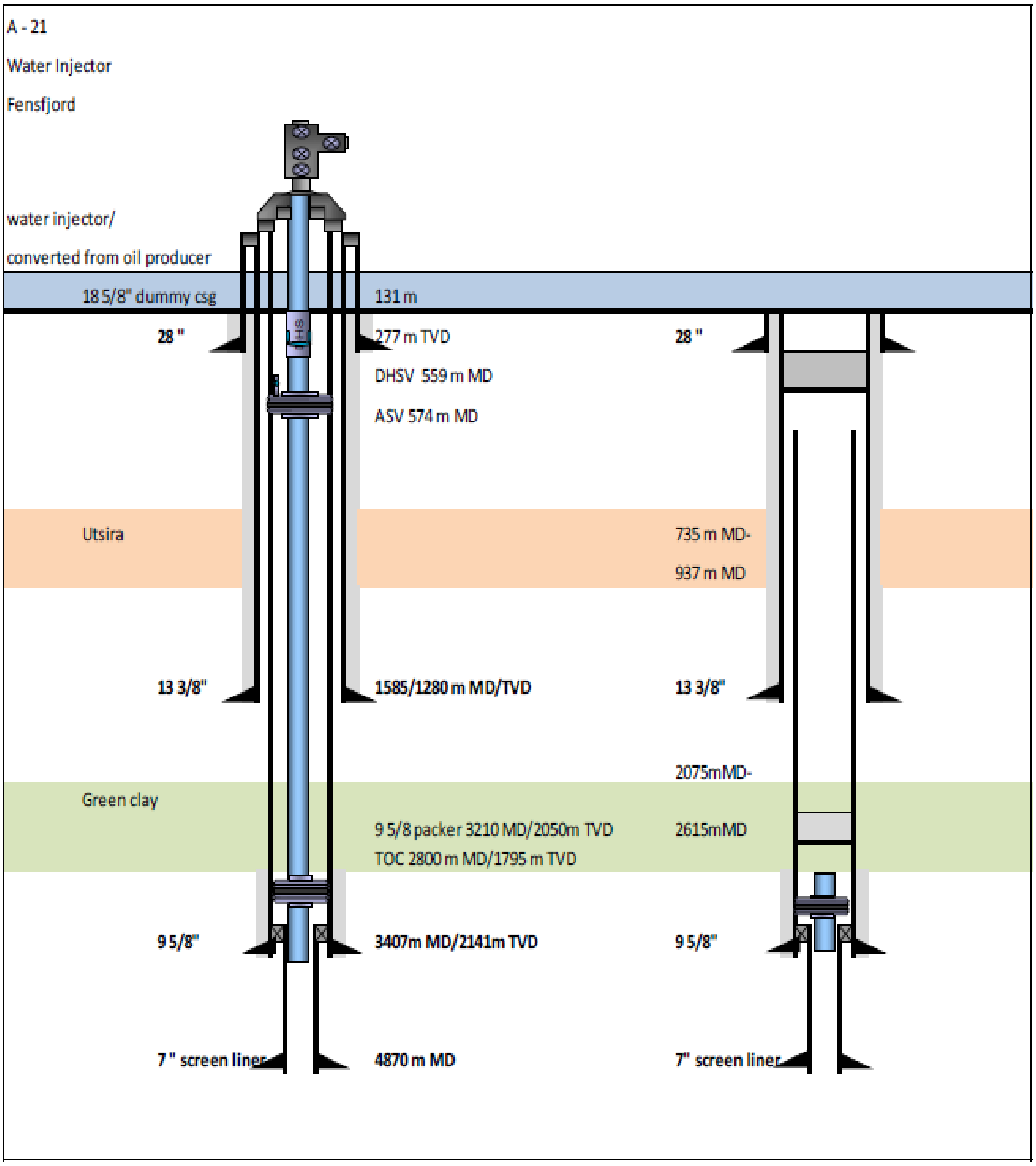

Figure 51: Well Design Associated with Procedure 2 [34]

Table 30: Operational Procedure 3

Procedure 3	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Tubing down to cut between DHSV and FLX
7	Retrieve CTA
8	Pull Upper Completion down to cut
9	Log 9 5/8" casing in Green Clay Interval
10	Set 9 5/8" Mechanical Plug as Base
11	Set Primary and Secondary barrier plugs
12	Tag/dress-off Plug
13	Nipple down BOP
14	N/D tubing Head
15	N/U BOP
16	Cut and Retrieve 9 5/8" casing shallow
17	Cut and Retrieve 13 3/8" casing shallow
18	Set 18 5/8" mechanical plug as base and pressure test
19	Set Environmental plug
20	Tag Plug
21	Remove Conductor and Casing Strings 5 m below seabed

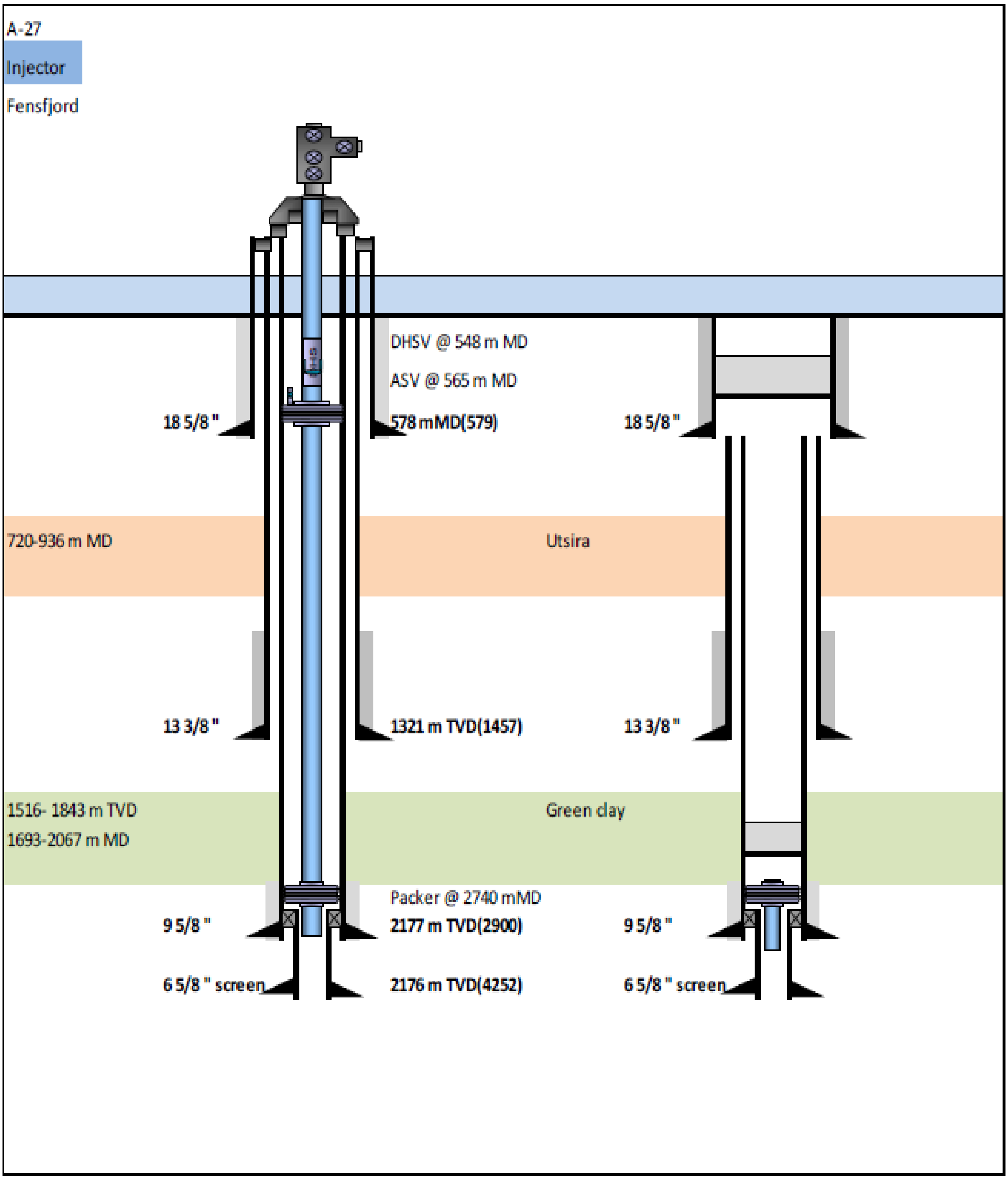

Figure 52: Well Design Associated with Procedure 3 [34]

Table 31: Operational Procedure 4

Procedure 4 (A-2 and A-3)	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Log 9 5/8" casing in Green Clay Interval
8	Set 9 5/8" Mechanical Plug as Base
9	Set Primary and Secondary barrier plugs
10	Tag/dress-off Plug
11	Nipple down BOP
12	N/D tubing Head
13	N/U BOP + P-test
14	Section Mill 9 5/8" and 13 3/8" casing shallow
15	Set 18 5/8" mechanical plug as base and pressure test
16	Set Environmental plug
17	Tag Plug
18	Retrieve 10 ¾" Surface tie-back casing shallow
19	Retrieve 13 3/8" Surface tie-back casing shallow
20	Remove Conductor and Casing Strings 5 m below seabed

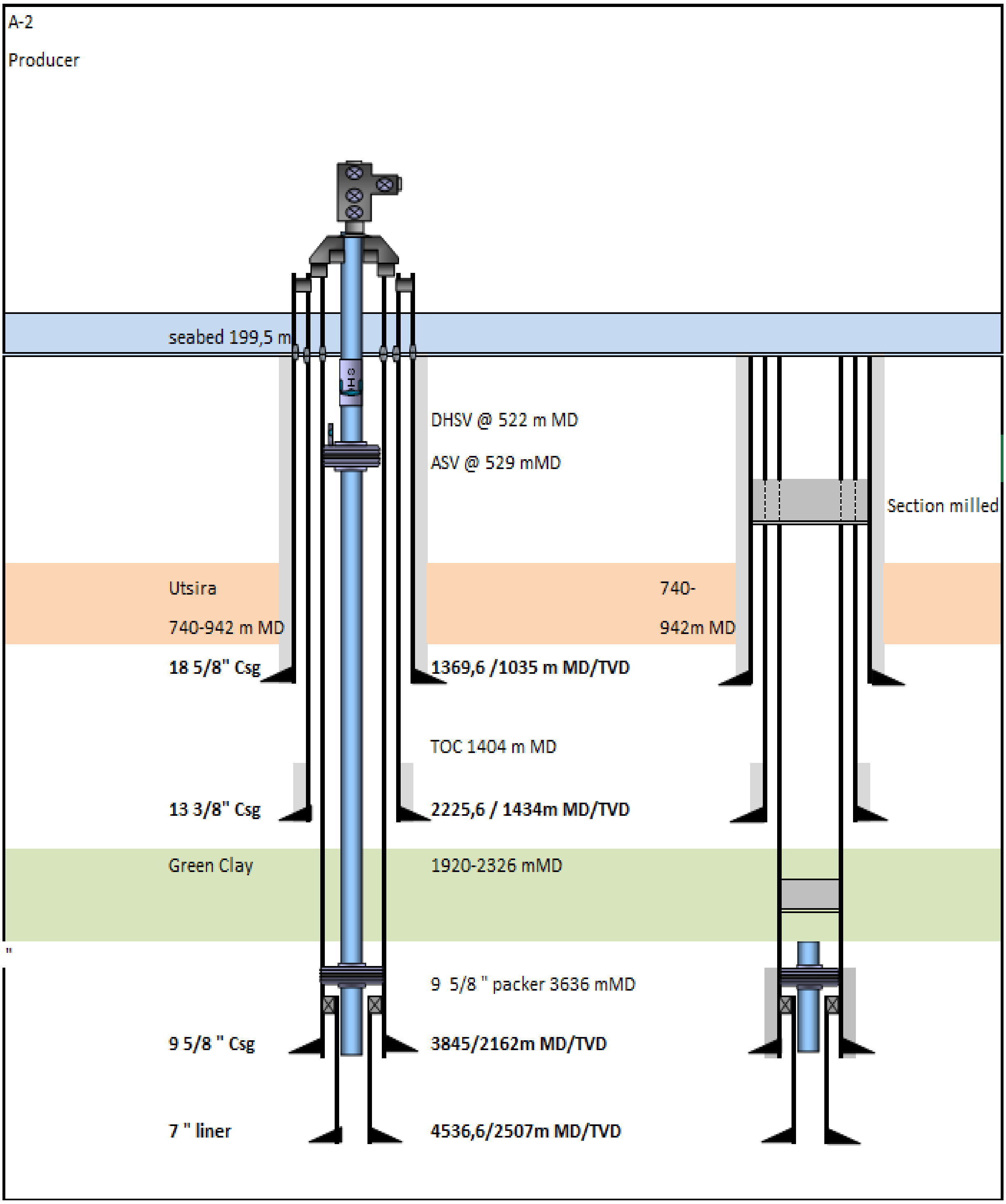

Figure 53: Well Design Associated with Procedure 4

Table 32: Operational Procedure 5

Procedure 5 (A-6)	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Section Mill 9 5/8" casing at Green Clay Interval
8	Log 9 5/8" casing in Green Clay Interval
9	Set 9 5/8" Mechanical Plug as Base
10	Set Primary and Secondary barrier plugs
11	Tag/dress-off Plug
12	Nipple down BOP
13	N/D tubing Head
14	N/U BOP + P-test
15	Section Mill 9 5/8" and 13 3/8" casing shallow
16	Set 18 5/8" mechanical plug as base and pressure test
17	Set Environmental plug
18	Tag Plug
19	Retrieve 10 ¾" Surface tie-back casing shallow
20	Retrieve 13 3/8" Surface tie-back casing shallow
21	Remove Conductor and Casing Strings 5 m below seabed

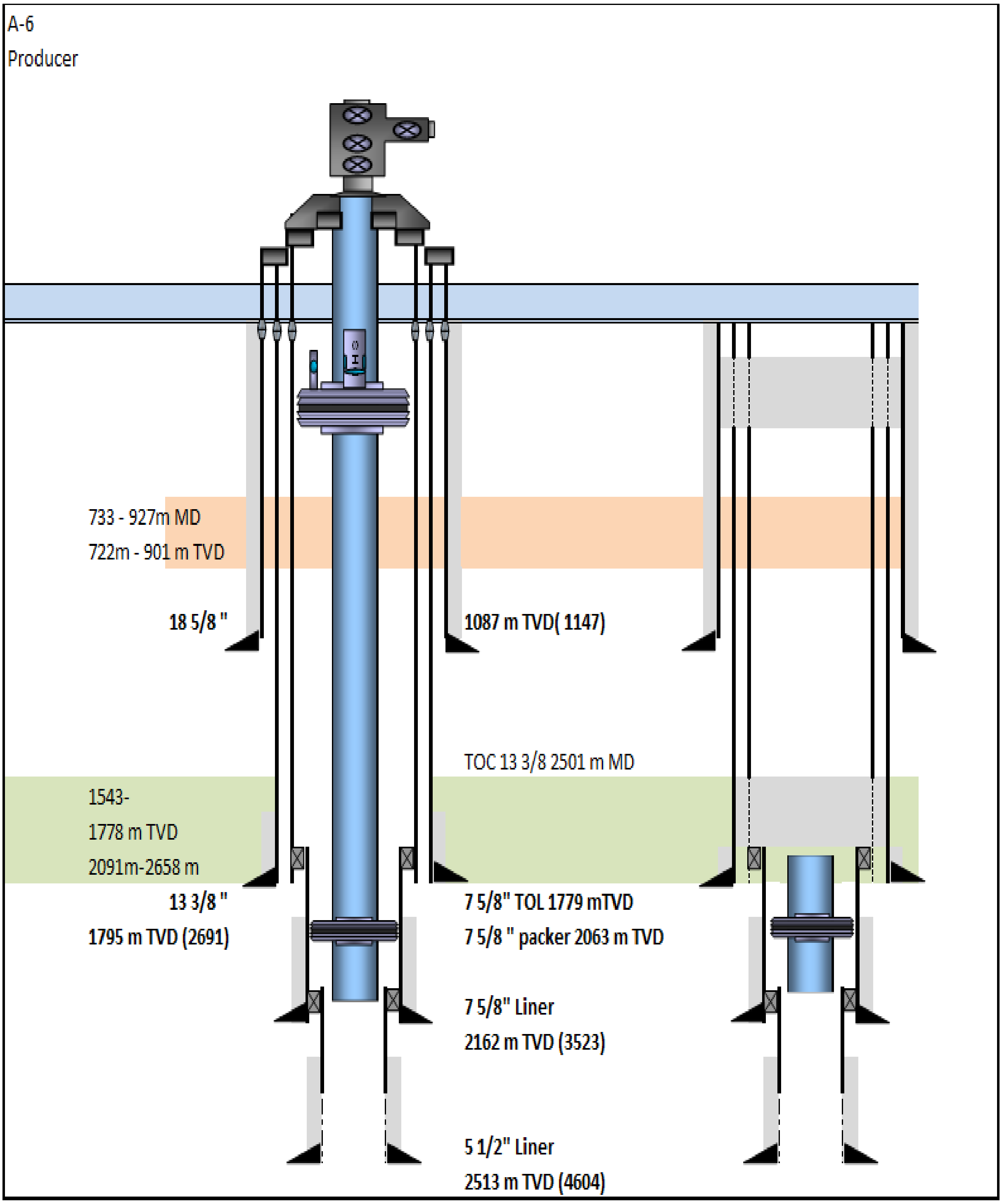

Figure 54: Well Design Associated with Procedure 5 [34]

Table 33: Operational Procedure 6

Procedure 6 (A-5)	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Tubing down to cut between DHSV and FLX
7	Retrieve CTA
8	Pull Upper Completion down to cut
9	Log 9 5/8" casing in Green Clay Interval
10	Set 9 5/8" Mechanical Plug as Base
11	Set Primary and Secondary barrier plugs
12	Tag/dress-off Plug
13	Nipple down BOP
14	N/D tubing Head
15	N/U BOP + P-test
16	Section Mill 9 5/8" and 13 3/8" casing shallow
17	Set 18 5/8" mechanical plug as base and pressure test
18	Set Environmental plug
19	Tag Plug
20	Retrieve 10 ¾" Surface tie-back casing shallow
21	Retrieve 13 3/8" Surface tie-back casing shallow
22	Remove Conductor and Casing Strings 5 m below seabed

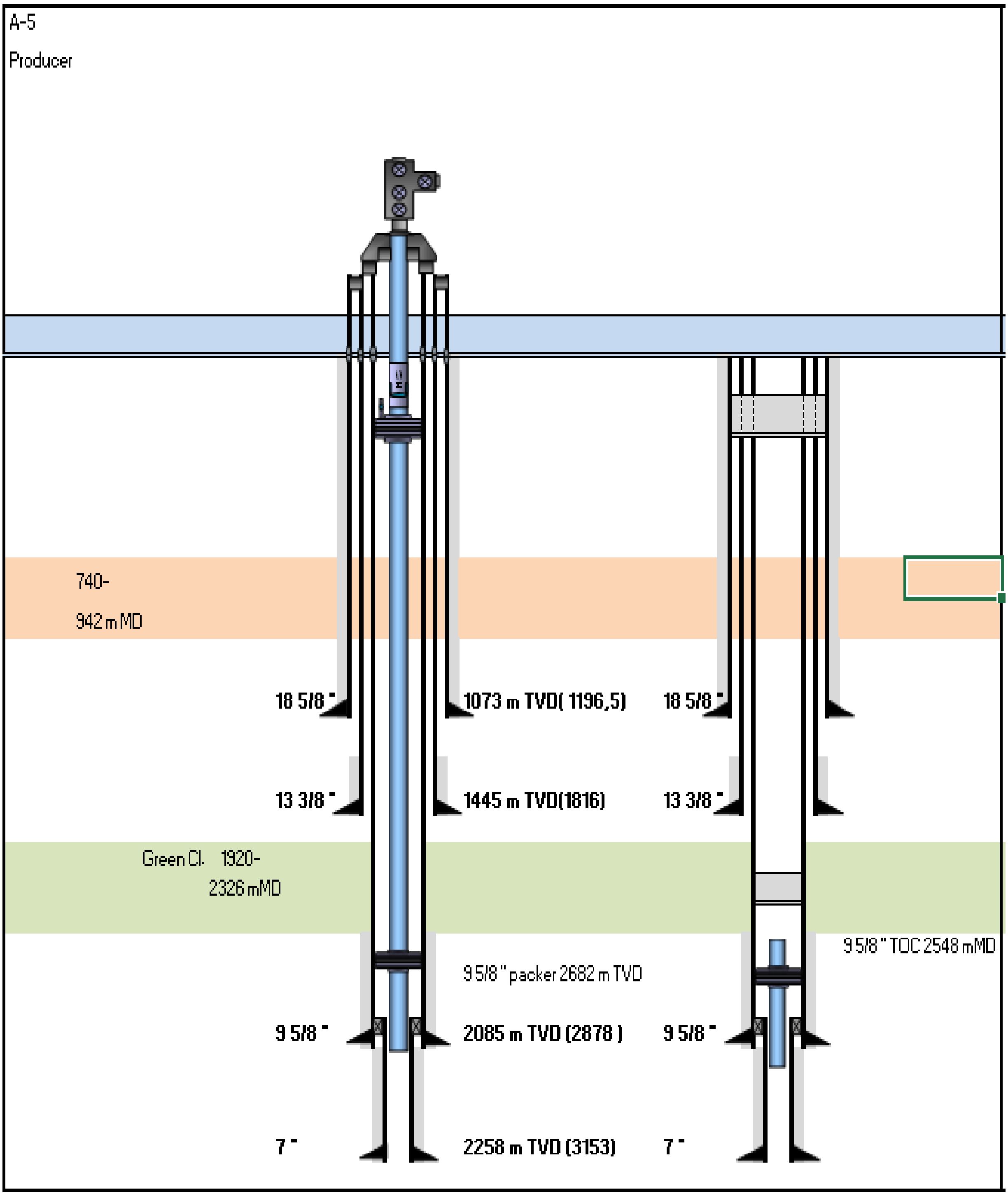

Figure 55: Well Design Associated with Procedure 6 [34]

Table 34: Operational Procedure 7

Procedure 7 (A-4)	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Tubing down to cut between DHSV and FLX
7	Retrieve CTA
8	Pull Upper Completion down to cut
9	Log 9 5/8" casing cement at 4000 m
10	Set 9 5/8" Mechanical Plug as Base
11	Set Primary and Secondary barrier plugs at 3700 m MD
12	Tag/dress-off Plug
13	Nipple down BOP
14	N/D tubing Head
15	N/U BOP + P-test
16	Section Mill 9 5/8" and 13 3/8" casing shallow
17	Set 18 5/8" mechanical plug as base and pressure test
18	Set Environmental plug
19	Tag Plug
20	Retrieve 10 ¾" Surface tie-back casing shallow
21	Retrieve 13 3/8" Surface tie-back casing shallow
22	Remove Conductor and Casing Strings 5 m below seabed

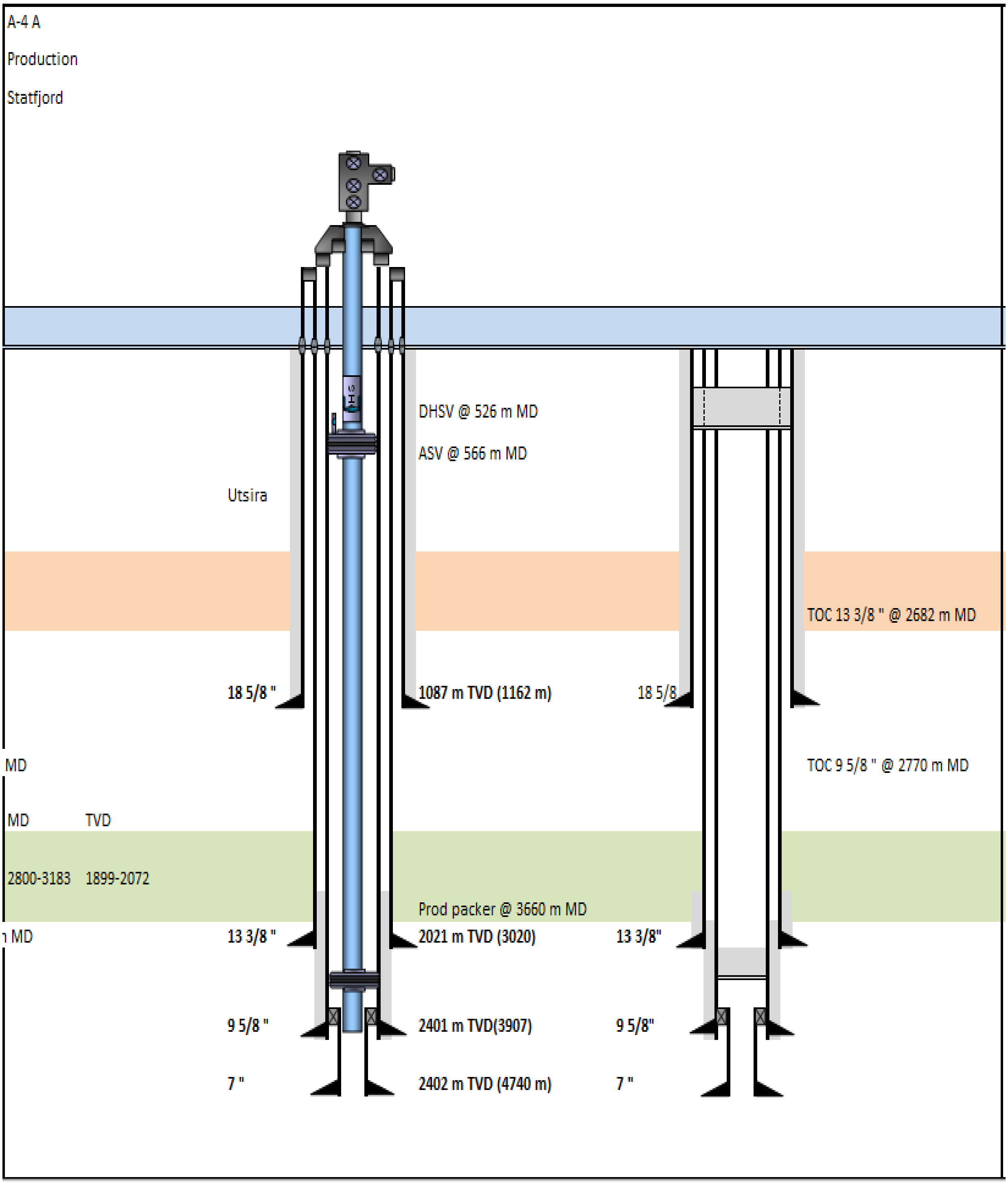

Figure 56: Well Design Associated with Procedure 7 [34]

Table 35: Operational Procedure 8

Procedure 8	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Set shallow Mechanical Plug
8	N/D BOP
9	N/D Tubing Head
10	N/U BOP and Risers + P-test
11	Retrieve shallow Mechanical Plug
12	Cut and pull tie-back casing deep (2500 m)
13	Log 13 3/8" casing in Green Clay Interval
14	Set 13 3/8" Mechanical Plug as Base
15	Set Primary and Secondary barrier plugs
16	Tag/dress-off Plug
17	Cut and Retrieve 13 3/8" casing shallow
18	Set 18 5/8" mechanical plug as base and pressure test
19	Set Environmental plug
20	Tag Plug
21	Remove Conductor and Casing Strings 5 m below seabed

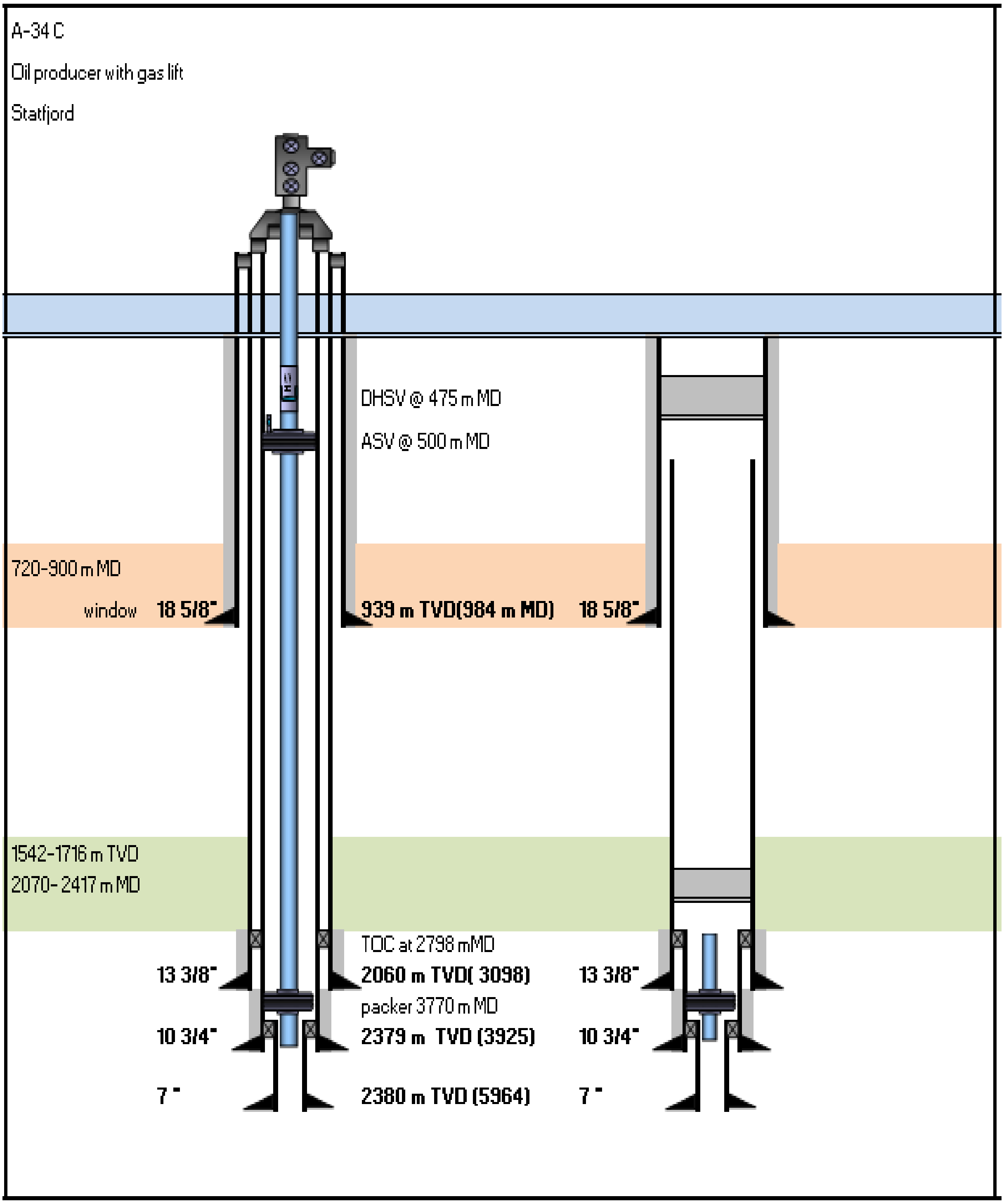

Figure 57: Well Design Associated with Procedure 8 [34]

Table 36: Operational Procedure 9

Procedure 9	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull tubing down to cut between DHSV and FLX
7	Retrieve CTA
8	Pull Upper Completion down to cut
9	Set shallow Mechanical Plug
10	N/D BOP
11	N/D Tubing Head
12	N/U BOP and Risers + P-test
13	Retrieve shallow Mechanical Plug
14	Cut and pull tie-back casing deep (2500 m)
15	Log 13 3/8" casing in Green Clay Interval
16	Set 13 3/8" Mechanical Plug as Base
17	Set Primary and Secondary barrier plugs
18	Tag/dress-off Plug
19	Cut and Retrieve 13 3/8" casing shallow
20	Set 18 5/8" mechanical plug as base and pressure test
21	Set Environmental plug
22	Tag Plug
23	Remove Conductor and Casing Strings 5 m below seabed

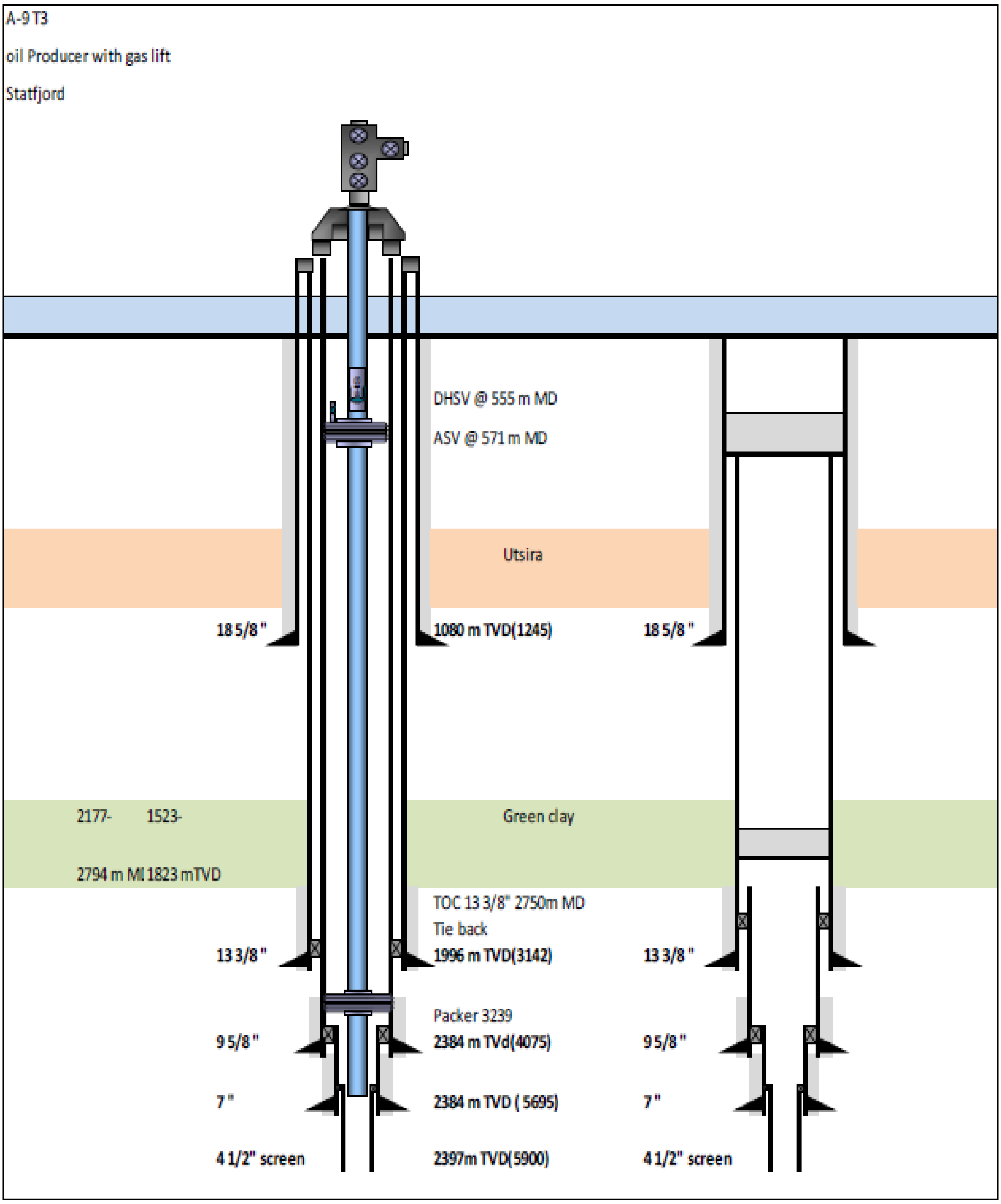

Figure 58: Well Design Associated with Procedure 9 [34]

Table 37: Operational Procedure 10

Procedure 10	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Nipple down BOP
8	N/D tubing Head
9	N/U BOP + P-test
10	Cut and Retrieve 13 3/8" casing shallow
11	Set 18 5/8" mechanical plug as base and pressure test
12	Set Environmental plug
13	Tag Plug
14	Remove Conductor and Casing Strings 5 m below seabed

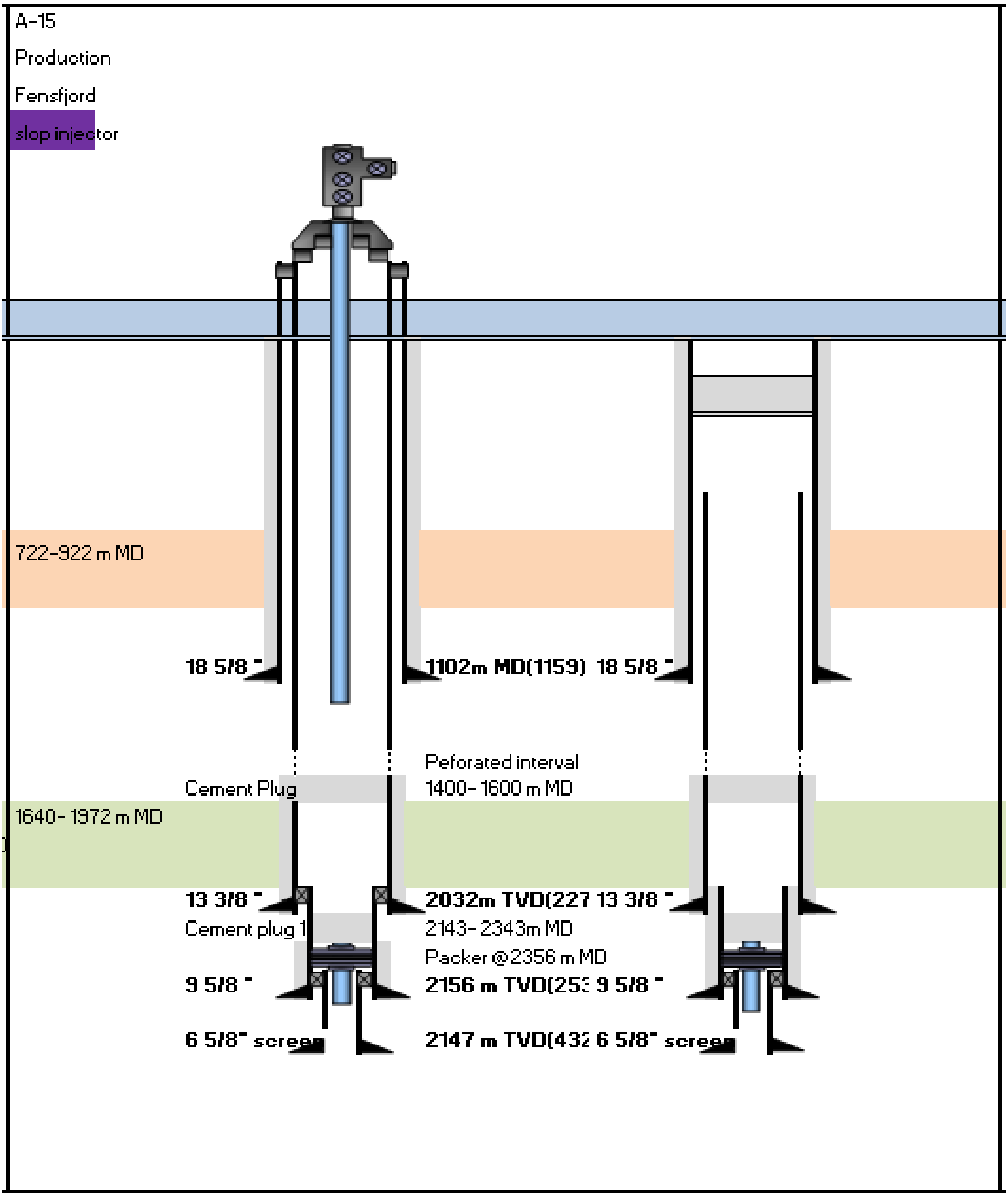

Figure 59: Well Design Associated with Procedure 10 [34]

Table 38: Operational Procedure 11

Procedure 11	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Set 18 5/8" mechanical plug as base and pressure test
8	Set Environmental plug
9	Tag Plug
10	Remove Conductor and Casing Strings 5 m below seabed

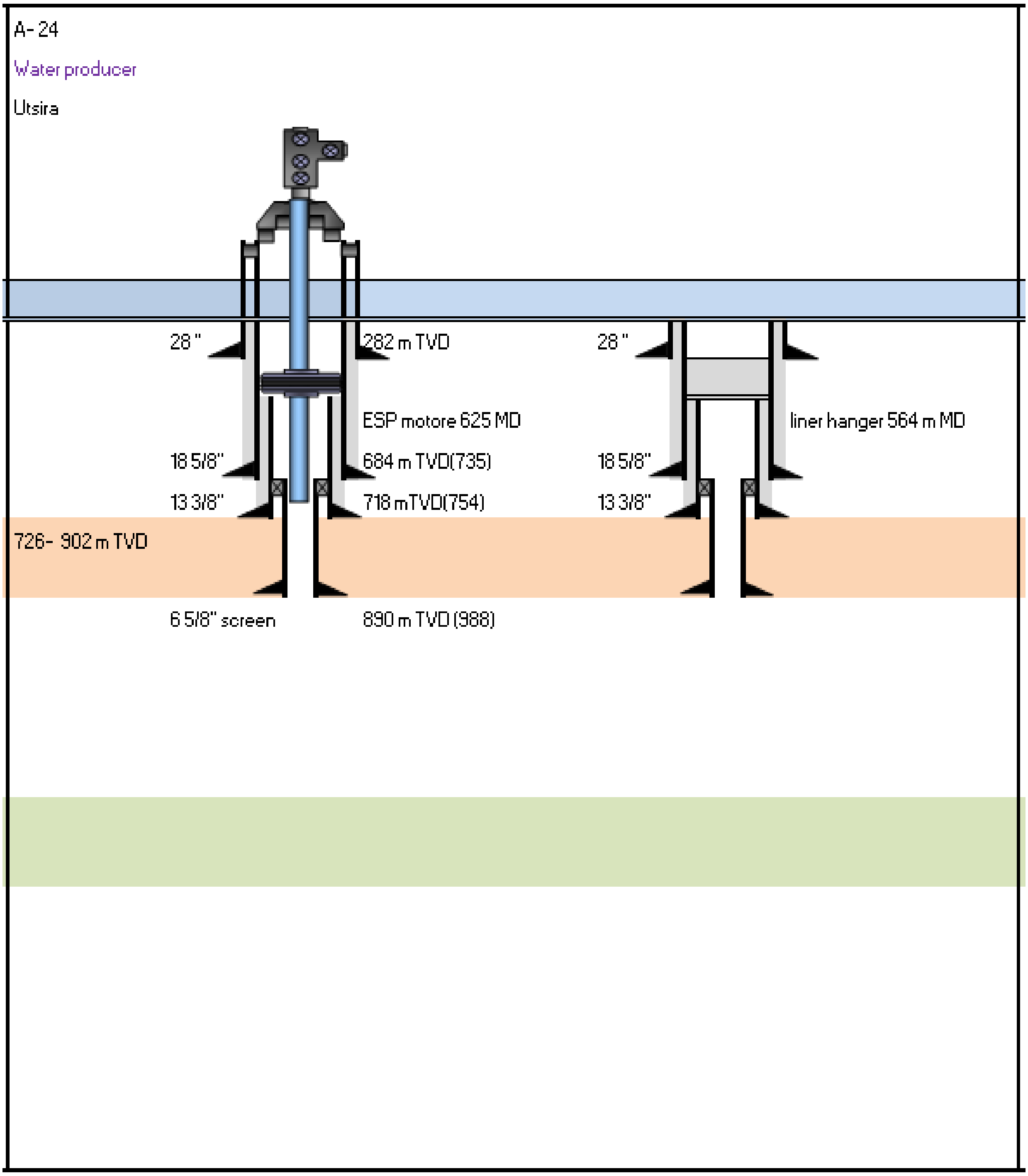

Figure 60: Well Design Associated with Procedure 11 [34]

Table 39: Operational Procedure 12

Procedure 12	
1	Skid Rig
2	Intervention
3	Retrieve XT
4	N/U BOP and Risers + pressure test
5	Pump open the shallow set plug
6	Pull Upper Completion down to cut
7	Nipple down BOP
8	N/D tubing Head
9	N/U BOP + P-test
10	Cut and Retrieve 10 3/4" tie-back casing shallow
11	Cut and Retrieve 13 3/8" casing shallow
12	Set 18 5/8" mechanical plug as base and pressure test
13	Set Environmental plug
14	Tag Plug
15	Remove Conductor and Casing Strings 5 m below seabed

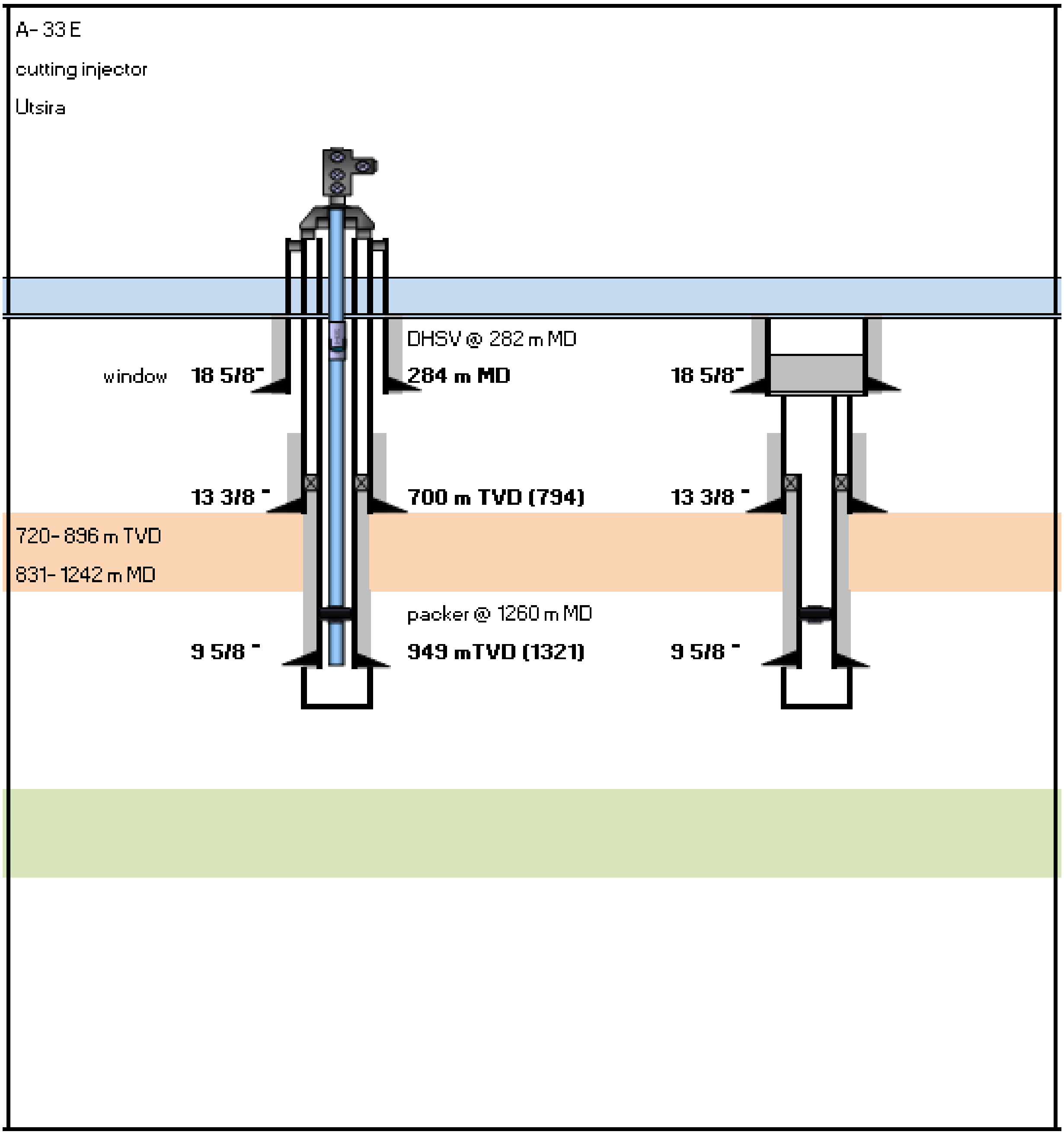

Figure 61: Well Design Associated with Procedure 12 [34]

APPENDIX C Unplanned Events with their Associated Procedure

Table 40: Likely Unplanned Events on Brage with Their Associated Procedure

	Procedures												Probability (%)
Unplanned Events	1	2	3	4	5	6	7	8	9	10	11	12	
Stuck Tubing (OLD ASV)		x	x			x	x		x				20
Stuck Tubing (New/No ASV	x			x	x			x		x	x	x	15
Problems To Cut & Retrieve Tie-Back Casing								x	x			x	10
Poor Cement Job	x	x	x	x		x	x	x	x				10
Section Milling Fails (shallow)				x	x	x	x						15
Insufficient Grenn Clay Bonding	x	x	x	x	x	x	x	x	x				10
Section Milling Fails (deep)					x								15
Problems Retrieving WH, Conductor & Casings	x	x	x	x	x	x	x	x	x	x	x	x	10

Procedure 3

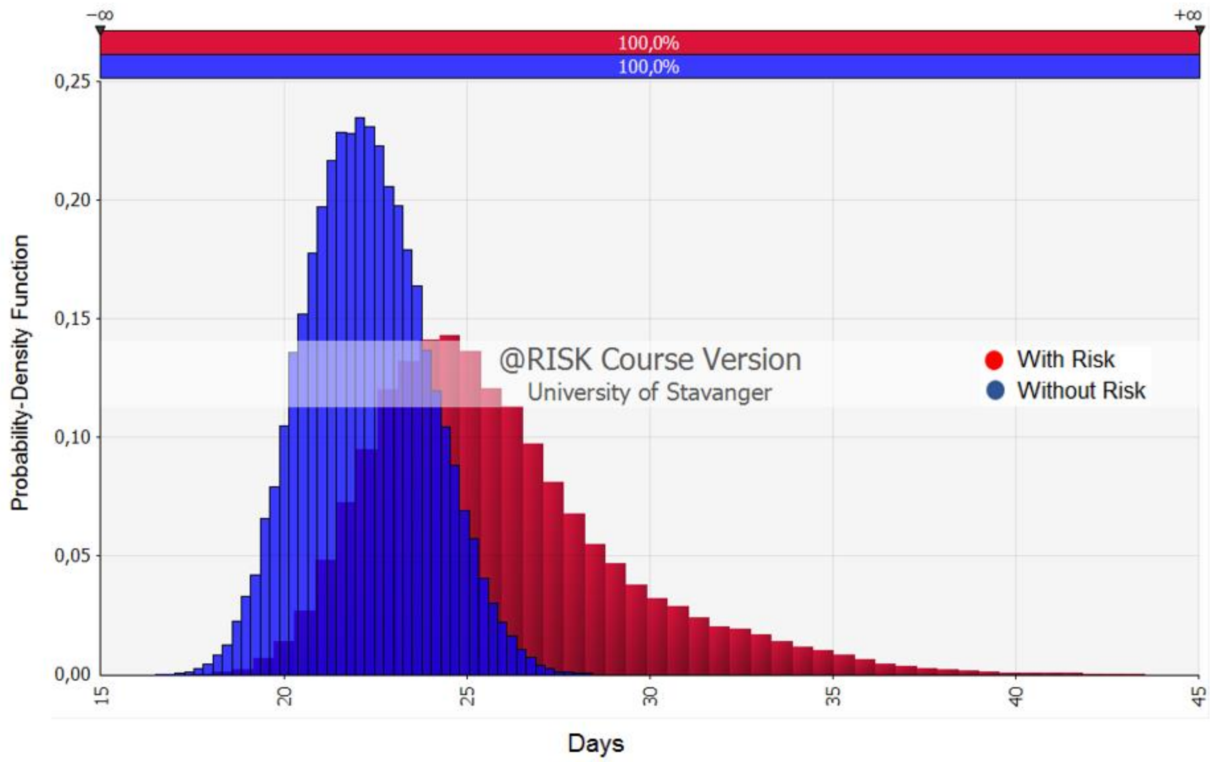

Figure 62: The Probability Density Functions for Procedure 3

Table 41: Statistic Values for Procedure 3

Statistic Values	Without Risk (days)	With Risk (days)
Mean	22,2	25,8
P10	20,1	22,0
P50	22,2	25,2
P90	24,4	30,5
Standard Deviation	1,65	3,4

In addition to the operations in Procedure 2, Procedure 3 also involve shallow cut and retrieval of 13 3/8” casing. This causes an increase in the mean, P 10, P 50 and P 90 values.

Procedure 4

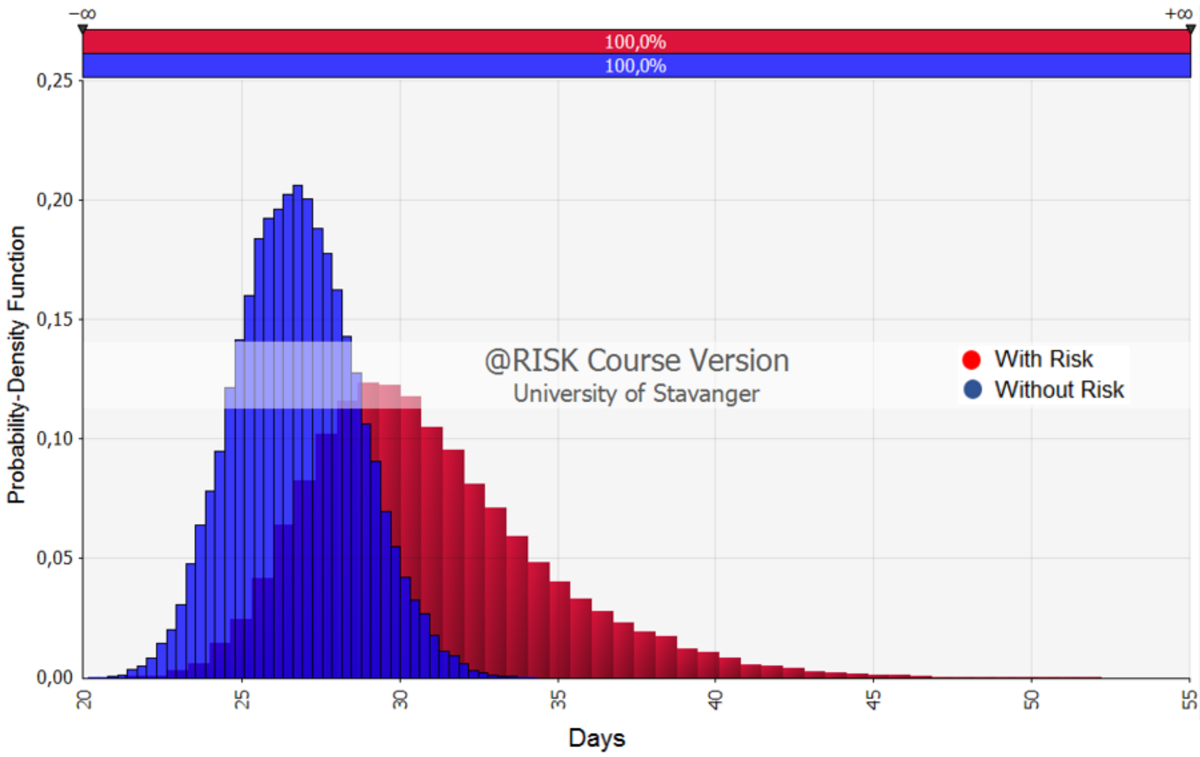

Figure 63: The Probability Density Functions for Procedure 4

Table 42: Statistic Values for Procedure 4

Statistic Values	Without Risk	With Risk
Mean	26,8	30,8
P10	24,3	26,6
P50	26,7	30,3
P90	29,2	35,9
Standard Deviation	1,9	3,7

Procedure 4 involves section milling of two casings shallow and thus, increases the mean duration to 26.8 and 30.8 days for respectively with and without risk. We can also observe that a greater percentage of the well will fall in the tail to the right. As the milling process is a complex operation that contains more uncertainty, this is as expected. We also observe an increase in standard deviation.

Procedure 6

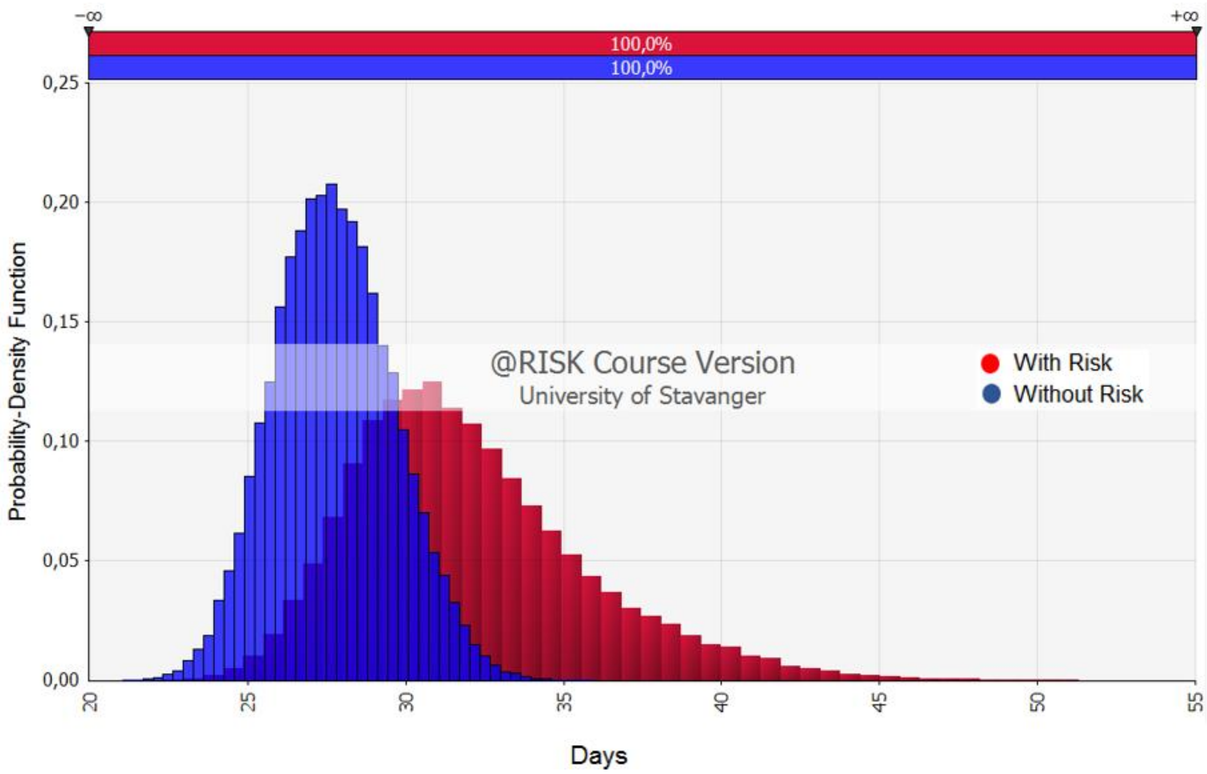

Figure 64: The Probability Density Functions for Procedure 6

Table 43: Statistic Values for Procedure 6

Statistic Values	Without Risk	With Risk
Mean	27,7	31,9
P10	25,4	27,8
P50	27,682	31,4
P90	30,2	37,1
Standard Deviation	1,8	3,7

In addition to the operations conducted in Procedure 4, Procedure 6 also include removal of the "old" type of ASV. The mean thereby increases by *one* day.

Procedure 7

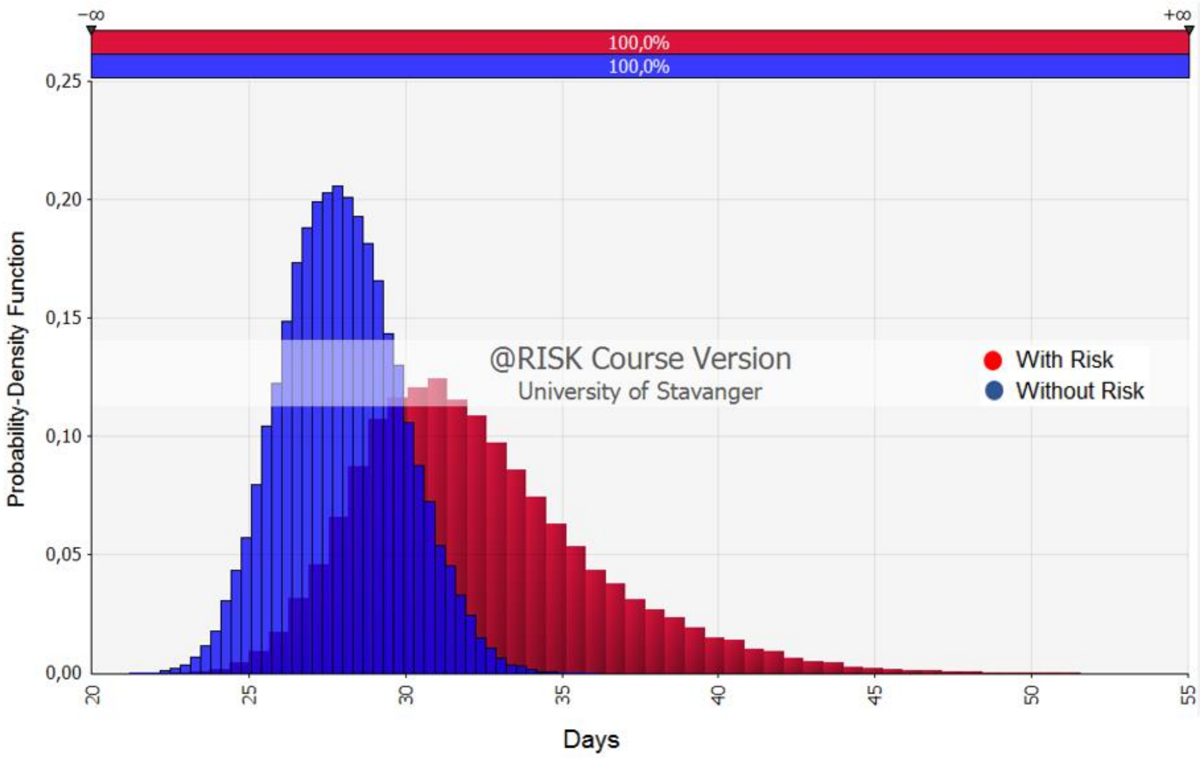

Figure 65: The Probability Density Functions for Procedure 7

Table 44: Statistic Values for Procedure 7

Statistic Values	Without Risk	With Risk
Mean	27,9	32,2
P10	25,6	28,0
P50	27,9	31,7
P90	30,4	37,3
Standard Deviation	1,9	3,7

Procedure 7 is only applicable for well A-4. The procedure is as Procedure 6, except that the primary and secondary barrier plug is not to be set in the Green Clay interval. To avoid section milling of 9 5/8” casing in the Green Clay interval, the cement plugs is placed inside the 9 5/8” casing below the 13 3/8” casing shoe (see APPENDIX A, Procedure 7). As the cement plugs is placed deeper than for Procedure 6, the mean duration for Procedure 7 is slightly higher.

Procedure 8

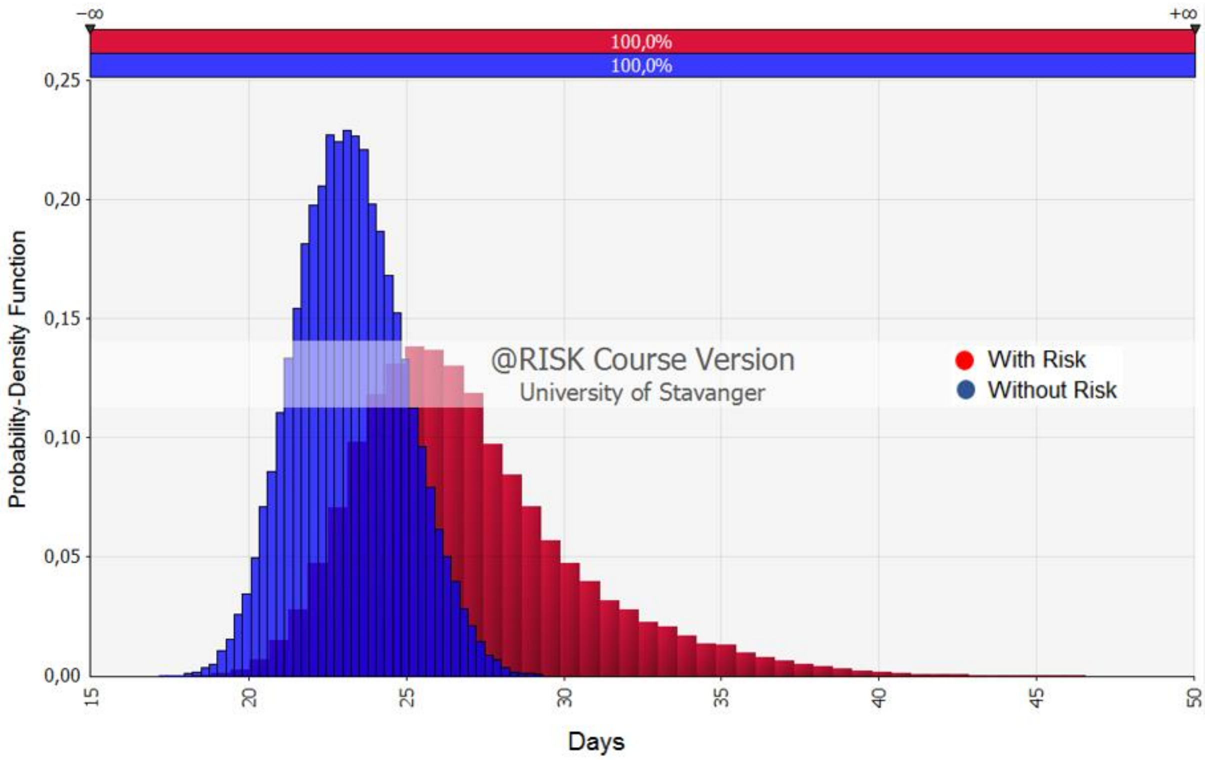

Figure 66: The Probability Density Functions for Procedure 8

Table 45: Statistic Values for Procedure 8

Statistic Values	Without Risk	With Risk
Mean	23,2	26,9
P10	21,0	23,1
P50	23,2	26,3
P90	25,5	31,6
Standard Deviation	1,7	3,5

Procedure 8 concerns the 15 wells with production liner and tie-back casing and is the procedure that applies to the greatest number of wells. We observe that uncertainty related to these wells are less than for Procedure 4-7, but greater than for the first three procedures. This is due to the uncertainty related to retrieving the tie-back casing deep.

Procedure 9

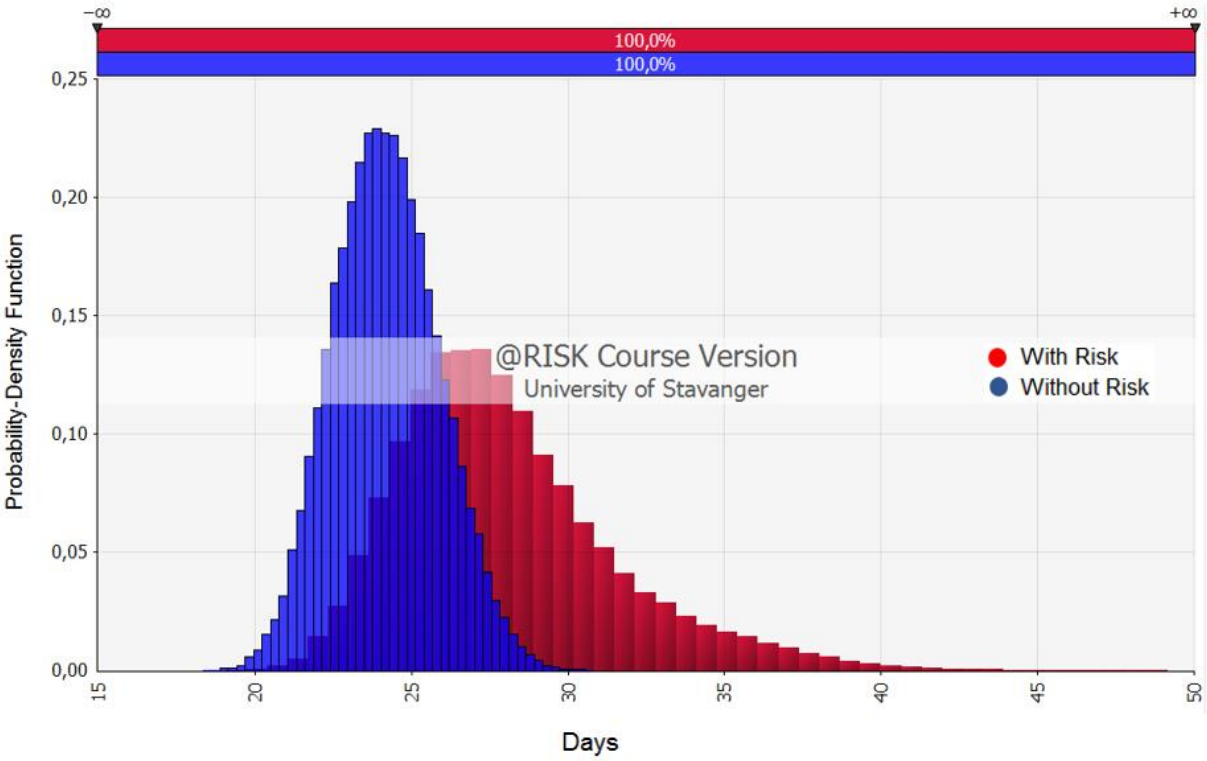

Figure 67: The Probability Density Functions for Procedure 9

Table 46: Statistic Values for Procedure 9

Statistic Values	Without Risk	With Risk
Mean	24,2	28,0
P10	22,1	24,2
P50	24,1	27,4
P90	26,4	32,7
Standard Deviation	1,7	3,4

Procedure 9 is identical to Procedure 8 except for the steps concerning ASV retrieval. Thus, the mean duration is greater.

Procedure 10

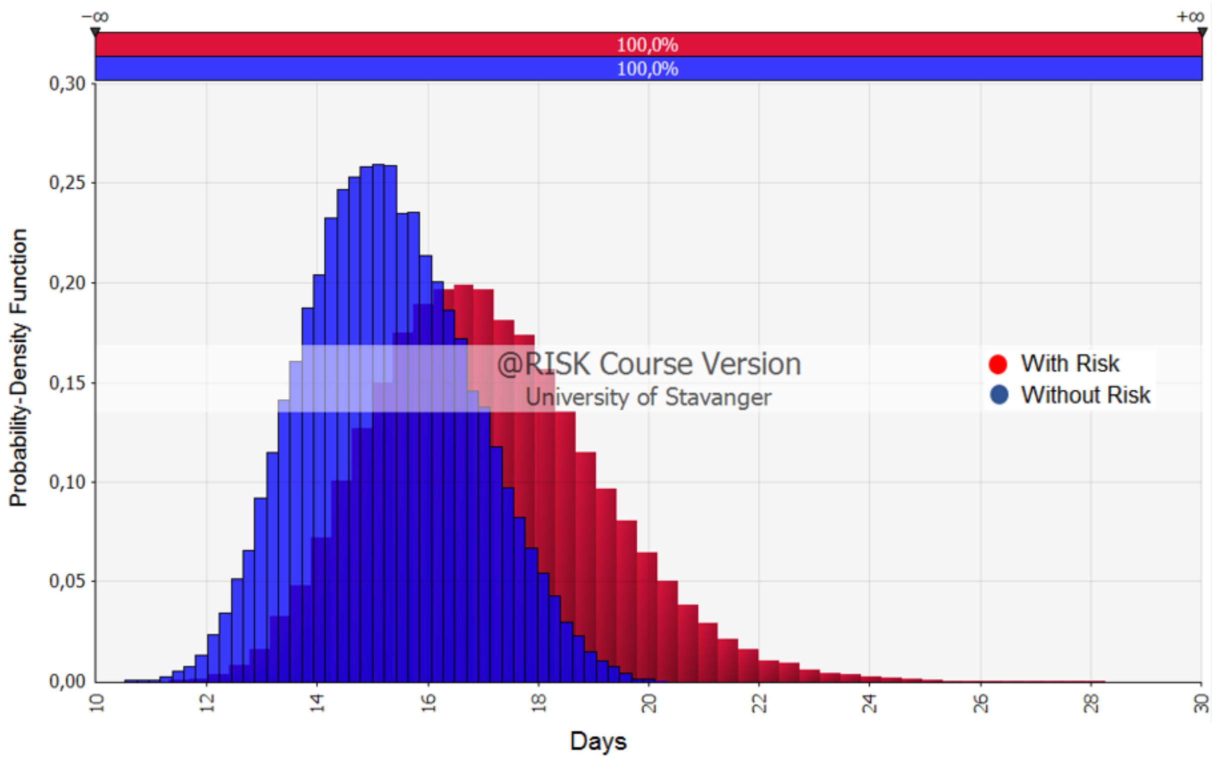

Figure 68: The Probability Density Functions for Procedure 10

Table 47: Statistic Values for Procedure 10

Statistic Values	Without Risk	With Risk
Mean	15,3	17,1
P10	13,4	14,6
P50	15,2	16,9
P90	17,3	19,7
Standard Deviation	1,5	2,0

Procedure 10 applies to the Oligocene slope injector at Brage. As the primary and secondary barrier plugs already are in place, fewer operational steps are needed and thus, the mean duration is less compared to the previous procedures. The number of unplanned events concerned is also reduced, leading to less uncertainty in the estimates.

Procedure 12

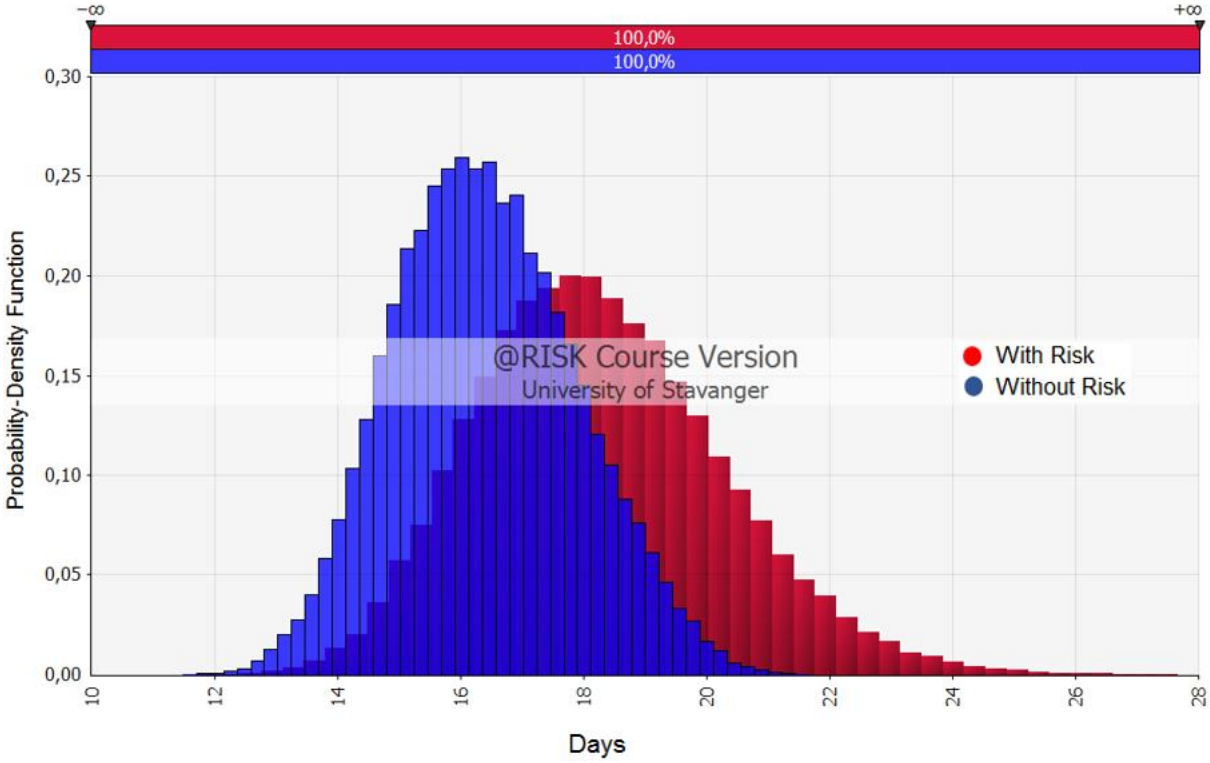

Figure 69: The Probability Density Functions for Procedure 12

Table 48: Statistic Values for Procedure 12

Statistic Values	Without Risk	With Risk
Mean	16,4	18,3
P10	14,5	15,8
P50	16,3	18,1
P90	18,4	20,9
Standard Deviation	1,5	2

The Effect of Including Learning to Procedure 9 (7 wells)

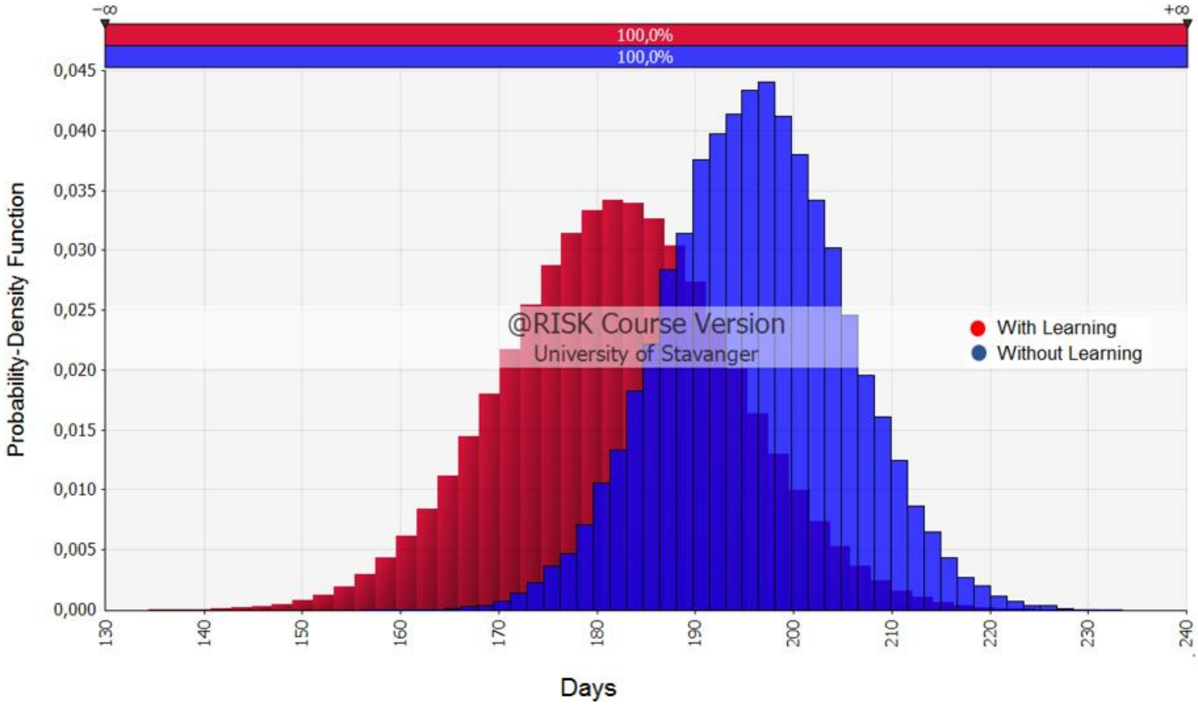

Figure 70: The Probability Density Functions for 7 Wells Associated with Procedure 8

Table 49: Statistic Values for 7 Wells (Procedure 9)

Statistic Values	Without Learning (days)	With Learning (days)
Mean	196,1	182,2
P10	184,4	167,3
P50	196,0	182,2
P90	207,9	197,2
Standard Deviation	9,1	11,6