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Author: Olav Fjelde (signature of author)
Supervisor(s): Fatemeh Moeinikia External Supervisor: Jan Arild Skappel	
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Abstract

Production of oil on the Norwegian continental shelf started in the early 70's. Many of these fields are now reaching the end of their production time. The industry is now awaiting a “plug wave” in the not too distant future. Decommission is a time-consuming procedure, and the cost of P&A can end up being 25 % of the total cost of the well.

The task given from Wintershall was to plan P&A operation by setting a dual barrier plug against the creeping clay in the Hordaland formation. The Hordaland green clay will creep in and seal around the casing and create a bonding with the casing. This method has saved operators on the Norwegian continental shelf for millions of NOK, by avoiding milling or squeeze cement job.

All the wells at Brage require permanent P&A in order to control subsurface pressure and prevent the free flow of pore fluids to the seabed. The wells at Brage was categorized depending on the different casing design. The objective was to determine the time for P&A for every category.

There were three different casing designs that stood out: pre-drilled wells, production liner with tie-back casing and simplified casing design. The most likely time for plugging the 40 wells at Brage is estimated to be around 3 years.

The time estimate is done with the technology available today. In the future there might be new technology that will enable the operator to P&A the field in a more cost-effective way. Many service companies are working on developing tomorrows P&A solution. Some of the new technologies will be presented and discussed in this thesis, together with the use of formation as a barrier.

Table of Contents

<u>ACKNOWLEDGMENT</u>	<u>2</u>
<u>ABSTRACT</u>	<u>3</u>
<u>LIST OF FIGURES</u>	<u>7</u>
<u>LIST OF TABLES</u>	<u>8</u>
<u>LIST OF ABBREVIATIONS</u>	<u>9</u>
<u>1 INTRODUCTION</u>	<u>10</u>
1.1 BACKGROUND	10
1.2 DEFINITION OF THESIS	11
<u>2 PERMANENT P & A – LAWS AND REGULATIONS</u>	<u>12</u>
2.1 DEFINITION OF PLUG AND ABANDONMENT	13
2.2 THE PETROLEUM ACT	14
2.3 PETROLEUM SAFETY AUTHORITY	15
2.4 NORSOK D-010	16
2.4.1 WELL BARRIER	16
2.4.2 PERMANENT ABANDONMENT	19
<u>3 PLUG & ABANDONMENT</u>	<u>27</u>
3.1 P&A IN NORWAY	27
3.2 PHASES OF WELL ABANDONMENT	28
3.3 TRADITIONAL BRAGE PLUG & ABANDONMENT:	29
3.4 CHALLENGES OF P & A OPERATIONS IN THE NORTH SEA	37
3.4.1 WEATHER	37
3.4.2 KNOWLEDGE OF WELL SITUATION	37
3.4.3 MILLING	38
3.4.4 CUTTING AND REMOVAL OF CASING	39
3.4.5 REMOVAL OF CONTROL LINES	39
3.4.6 LOG CEMENT THROUGH MULTIPLE CASINGS	39

4	THE BRAGE FIELD	40
4.1	GEOLOGY	41
4.2	RESERVOIR	42
4.2.1	STATFJORD	43
4.2.2	FENSFJORD	43
4.2.3	SOGNEFJORD	43
4.2.4	BRENT	43
4.3	BRAGE PLATFORM	44
5	PLUG & ABANDONMENT PROCEDURES ON BRAGE	45
5.1	PRE-DRILLED WELLS	46
5.1.1	PERMANENT PLUG & ABANDONMENT PROPOSAL FOR PRE-DRILLED WELL	47
5.1.2	SKETCHES FOR PRE-DRILLED WELLS	48
5.2	PRODUCTION LINER WITH TIE-BACK CASING	51
5.2.1	PERMANENT PLUG & ABANDONMENT PROPOSAL FOR WELLS WITH PRODUCTION LINER AND TIE-BACK	52
5.2.2	SKETCHES FOR WELLS WITH PRODUCTION LINER AND TIE-BACK CASING.	53
5.3	SIMPLIFIED CASING DESIGN	74
5.3.1	PERMANENT ABANDONMENT PROPOSAL FOR SIMPLIFIED CASING DESIGN	75
5.3.2	SKETCHES FOR WELLS WITH SIMPLIFIED CASING DESIGN	76
5.4	UTSIRA AND OLIGOCENE WELLS	85
5.4.1	OLIGOCENE SLOPE INJECTOR	85
5.4.2	UTSIRA WATER PRODUCERS	87
5.4.3	CUTTINGS INJECTOR	89
5.5	WELLS WITH A DUAL BARRIER PLUG SET BELOW THE HORDALAND FORMATION	91
5.5.1	PRE-DRILLED WITH 13 3/8" CASING SHOE BELOW GREEN CLAY LAYER	91
5.5.2	A-8 WITH 13 3/8" CASING SHOE BELOW GREEN CLAY LAYER	94
6	TIME ESTIMATION	96
6.1	P&A OF THE BRAGE FIELD	105
7	DISCUSSION	106
7.1	UNEXPECTED EVENTS	106
7.2	TECHNOLOGY	108
7.2.1	STEEL PIPE REMOVAL BY CONTROLLED CORROSION REACTION	108
7.2.2	INTERWELL	109
7.2.4	DOWNHOLE TUBING DISPOSAL	110
7.3	FORMATION AS A BARRIER	111
7.4	GUIDELINES	112

8	<u>CONCLUSION</u>	114
9	<u>RECOMMENDATION FOR FUTURE WORK</u>	116
	<u>REFERENCES:</u>	117
	<u>APPENDIX A</u>	120

List of Figures

Figure 1-Governing Hierarchy in the petroleum sector [3]	12
Figure 2-Organisation of petroleum activities in Norway [6]	15
Figure 3- WBS from Brage [8]	18
Figure 4- Permanent well barriers [4]	19
Figure 5- Minimum setting depth depending on the fracture pressure of impermeable formation. [9]	21
Figure 6-Historical timeline of NCS [10].....	27
Figure 7 Location and overview of the Brage field [9].....	40
Figure 8: Overview of the Brage overburden [21].....	41
Figure 9-Overview Brage reservoir [21]	42
Figure 10-production from the different reservoirs at the Brage field [21].....	42
Figure 11- Brage Platform [22].....	44
Figure 12- Pre-drilled well A-2.....	48
Figure 13: Pre-drilled well A-5 Producer	49
Figure 14:Pre-drilled well A-5 Injector	50
Figure 15:A-1: Pre-drilled but later sidetracked	53
Figure 16: Well A-7: producer with gas lift	54
Figure 17: Well A-9: Producer with gas lift	55
Figure 18: Well A-10: Producer with gas lift	56
Figure 19: Well A-11: Oil producer with gas lift.....	57
Figure 20: Well A-13: Producer with gas lift	58
Figure 21: Well A-14: Producer with gas lift	59
Figure 22: Well A-16: Producer with gas lift	60
Figure 23: Well A-17: Producer with gas lift	61
Figure 24: Well A-18: Producer with gas lift	62
Figure 25: Well A-19: Producer with gas lift	63
Figure 26: Well A-20: Producer with gas lift	64
Figure 27: Well A-22: Water injector	65
Figure 28: Well A-23: Producer with gas lift	66
Figure 29: Well A-28: Producer with gas lift	67
Figure 30: Well A-31: Producer with gas lift	68
Figure 31: Well A-32: Water injector	69
Figure 32: Well A-34: Producer with gas lift	70
Figure 33: Well A-35: Gas injector	71
Figure 34: Well A-37: producer with gas lift.....	72
Figure 35: Well A-40: Producer with gas lift	73
Figure 36: Well A-12: Water injector	76
Figure 37: Well A-21: water injector	77
Figure 38: Well A-25: Oil producer with gas lift.....	78
Figure 39: Well A-26: Water injector	79
Figure 40: Well A-27: Water injector	80
Figure 41: Well A-30: Producer with gas lift	81
Figure 42: Well A-36: Water injector	82
Figure 43: well A-38: Producer with gas lift	83

Figure 44: Well A-39: Producer with gas lift	84
Figure 45: Well A-15: Oligocene slope injector	86
Figure 46: Well A-24: Utsira water producer	87
Figure 47: Well A-29: Utsira water producer	88
Figure 48: Well A-33: Utsira cuttings injector	90
Figure 49: Well A-4: Pre-drilled with 13 3/8" casing shoe below green clay layer	92
Figure 50-Well A-4: Pre-drilled with 13 3/8" casing shoe below green clay layer	93
Figure 51: Well A-8: Producer with gas lift	95
Figure 52: Time distribution for P&A of a single: Pre-drilled with ASV	98
Figure 53: Time distribution for P&A of single well: Pre-drilled	98
Figure 54: Time distribution for P&A of a single well: production liner with ASV	99
Figure 55: Time distribution for P&A of single well: Production liner	99
Figure 56: Time distribution for P&A of a single well: Simplified casing design with ASV	100
Figure 57: Time distribution for P&A of a single well: Simplified casing design	100
Figure 58: Time distribution for P&A of a single well: Short 18 5/8"	101
Figure 59: Time distribution for P&A of a single well: Oligocene	101
Figure 60: Time distribution for P&A of single well: Utsira water producer	102
Figure 61: Time distribution for P&A of single well: Utsira cuttings injector.....	102
Figure 62: Time distribution for P&A of a single well: A-8	103
Figure 63: Time distribution of a single well: pre-drilled, below green clay	103
Figure 64- Time distribution for the P&A operation of the Brage field	105
Figure 65- Overview of time spent on WOW, NPT and Productive time based on data from Rushmore	107
Figure 66- Overview of P50 values for P&A of the different wells at Brage with the number of wells in each category given below each column	114

List of Tables

Table 1-Minimum number of well barriers [4].....	17
Table 2 - Operation time for the different wells at Brage.....	96
Table 3- Statistical properties of the forecast Result.....	104
Table 4- Statistical parameters for P&A of Brage.....	105
Table 5- Physical properties for cement and shale [31]	112

List of Abbreviations

ASV	Annular safety valve
BOP	Blowout preventer
CBL	Cement bond log
CDF	Cumulative distribution function
DHSV	Down hole safety valve
HSE	Health, safety and environment
LOT	Leak off test
LWIV	Light well intervention vessel
MD	Measured Depth
NCS	Norwegian continental shelf
NOK	Norwegian Krone
NORSOK	The Norwegian Shelf's competitive position
P & A	Plug and abandonment
PAF	Plug & Abandonment forum
PDF	Probability Density Forum
POOH	Pull out of hole
PSA	Petroleum Safety Authority
RIH	Run in hole
STOIP	Stock Tank Oil Initially In Place
TVD	True Vertical Depth
USIT	Ultra-sonic imager tool
WBE	Well Barrier Element
WBEAC	Well Barrier Element Acceptance Criteria
WBS	Well Barrier Schematic
WH	Wellhead
WOW	Wait on weather
XT	Christmas tree

1 Introduction

The objective is to plan the Plug and abandonment of the Brage field by setting a dual barrier plug against the creeping clay in the Hordaland formation, and make a time estimation of the operation. The well abandonment will be done in accordance with the Norwegian standard; NORSOK D-010. The standard serves as references in the authorities' regulations. The thesis contains the following chapters:

- Chapter 1: Introduction of the thesis
- Chapter 2: Laws, regulations and standard on NCS
- Chapter 3: General introduction of P & A and operational sequence
- Chapter 4: Overview of the Brage field
- Chapter 5: Planning of P & A for the Brage field
- Chapter 6: Time estimation
- Chapter 7: Discussions
- Chapter 8: Conclusion
- Chapter 9: Recommendations for future studies

1.1 Background

There has been an increasing focus on Plug & Abandonment (P&A) in Norway in the later years. Several fields on the NCS is entering their final production stage, and they need to be plugged in a safe manner when production is no longer profitable. There are currently around 2000 active wells and about 500 wells that are not active on the Norwegian Continental Shelf [1]. There are several reasons for a well to be plugged and abandoned: uncontrollable leakage, structural failure or when production is no longer profitable. Under one of these circumstances the well will be plugged and abandoned.

The P&A operation will be a considerable cost for the companies, since the operation is complex and time consuming. It is estimated that in some cases P&A of a well could easily contribute up to 25 % of drilling cost for an offshore exploration well in the North Sea [2]. If the P&A operation is considered at an early stage the operator can save a lot of time by verifying the barriers before the operation start.

In later years, there has been a lot of talks about using shale as a barrier element [1]. In the summer of 2016 the magazine TU published an article about how using shale as a barrier element could save billions of NOK. When it comes to P&A the well is often teared down without having verified if the barriers are already in place.

1.2 Definition of Thesis

The Brage field was developed in the early 90's, and production has been declining in recent years. The objective of this thesis is to start a preliminary discussion about how to decommission the Brage field and develop a time estimate for the operation.

The decommissioning will be executed in accordance with the regulations on the Norwegian continental shelf (NCS). Therefore, as a part of the literature study, chapter 2 is dedicated to laws and regulations governing P&A active on the NCS.

Further in the literature study there will be a short summary of the history on NCS, and some fields that is now coming into the later stage of production. Chapter 3 also gives a description of the different phases used when talking about P&A and presents a traditional P&A operation at Brage.

The task was to set a dual barrier plug against the creeping part of the Hordaland formation. Sketches were made for every well, showing the depth of the formation together with the casing design. Information about the different wells were found in the final well reports. Using the sketches, it was easy to identify which operation were required to set a plug against the creeping clay formation. The operation time were found from similar activities on the Brage field. Matlab were the programming tool of choice when performing the Monte Carlo simulations.

The main objectives were:

- Categorise the different wells at Brage, and find the most likely time for P&A of the given category
- Make a time estimation for P&A of the entire field.
- Discusses factors that might change the actual time of the operation.

2 Permanent P & A – laws and regulations

The Oil and gas activities on the NCS is governed by a number of rules, regulations and guidelines implemented by the Norwegian government. The purpose of this chapter is to give the reader overview of the different laws, regulations and Standards that control the activities on the NCS. The Governing Hierarchy in Norway is:

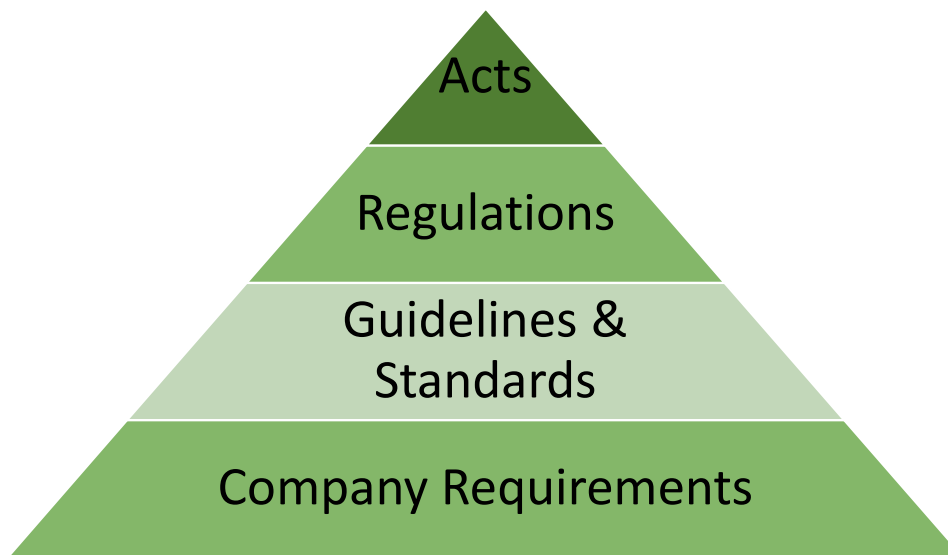


Figure 1-Governing Hierarchy in the petroleum sector [3]

Decommissioning activities on the Norwegian continental shelf are defined in the 1996 petroleum act. The role of the PSA on NCS is developing and enforcing regulations that govern health and safety. Guidelines aims to streamline a particular process, often by referring to a given standard as a way to fulfil the functional requirements in the regulation. NORSOK D-010 Well Integrity in Drilling and Well Operations presents specific regulations for decommissioning. The standard focuses on well integrity by defining the minimum functional and performance requirements and guidelines for well design, planning and execution of well activities on the NCS. [4]

2.1 Definition of Plug and abandonment

The purpose of this chapter is to define some key terms regarding P&A. NORSOK D-010 is the standard that covers the requirements and well integrity during plugging on the NCS. Before going further into the P&A operation, it is good to define some key terms from NORSOK. NORSOK divides between Temporary abandonment with/without monitoring and Permanent Abandonment [4]:

- **Plugging:** *“operation of securing a well by installing required well barriers”* [4]
- **Well barrier:** *“envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore, into another formation or to the external environment.”* [4]
- **Well barrier element:** *“a physical element which in itself does not prevent flow but in combination with other well barrier elements forms a well barrier”* [4]
- **Well Integrity:** *“application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids and well fluids throughout the life cycle of a well”.* [4]
- **Temporary Abandonment - with monitoring:** *“well status, where the well is abandoned and the primary and secondary well barriers are continuously monitored and routinely tested”* [4]. There is no maximum abandonment period.
- **Temporary abandonment – without monitoring:** *“well status, where the well is abandoned and the primary and secondary well barriers are not continuously monitored and routinely tested”* [4]. The maximum abandonment period shall be three years.
- **Permanently abandonment:** *“well status, where the well is abandoned permanently and will not be used or re-entered again.”* [4]

When reading through the regulations and standards like NORSOK D-010 its useful to know the difference between **shall** and **should**:

- **Shall:** “verbal form used to indicate requirements strictly to be followed in order to conform to the standard and form which no deviation is permitted, unless accepted by all involved parties.” [4]
- **Should:** “verbal form used to indicate that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others, or that certain course of action is preferred but not necessarily required. [4]

2.2 The Petroleum act

The petroleum Act (Act of 29 November 1996 No. 72 relating to petroleum activities) provides the general legal basis for resource management and the licensing system on the NCS. Section 5-1 in the petroleum act states the requirements for decommissioning plan. The section 5-1 Decommissioning plan state the following [5]:

*The licensee **shall** submit a decommissioning plan to the Ministry before a license according to Section 3-3 or Section 4-3 expires or is surrendered, or the use of a facility is terminated permanently. The plan **shall** contain proposals for continued production or shutdown of production and disposal of facilities. Such disposal may inter alia constitute further use in the petroleum activities, other uses, complete or part removal or abandonment.*

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

The petroleum act is on top of the Governing hierarchy, and is the basis of the decommissioning process. The Petroleum Act says that a decommissioning plan shall be submitted to the Ministry two to five years before the use of the facility ceases or the license expires.

2.3 Petroleum safety Authority

The Ministry of Labour and Social Affairs has the overall responsibility for the working environment Norway including the petroleum sector. The PSA is an independent government regulatory body under the Ministry of Labour. PSA was established on 1. Jan. 2004 and separated from NPD. In Figure 2 you can see how the government has organized the Petroleum sector.

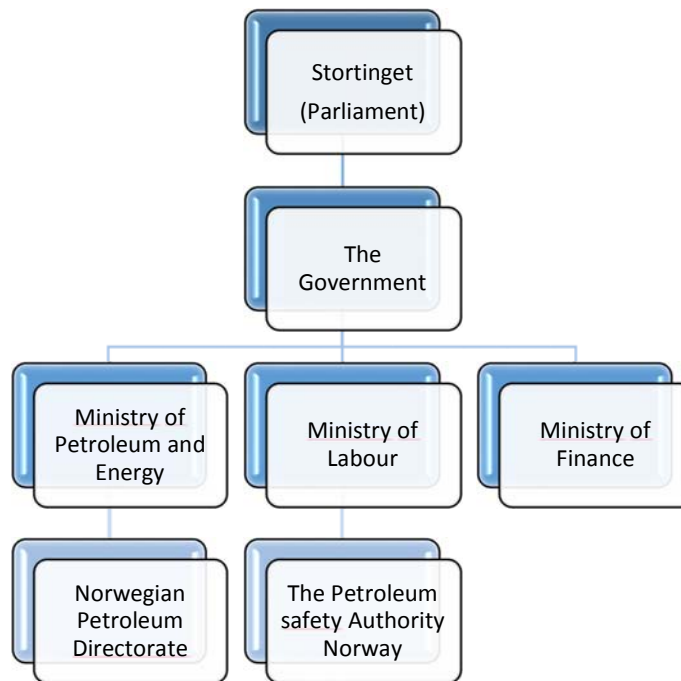


Figure 2-Organisation of petroleum activities in Norway [6]

The PSA is responsible for developing and enforcing regulations that contributes to the safety, emergency preparedness and the work environment in petroleum activities. That also include petroleum facilities on land like Kårstø. [7] The four most central regulations developed PSA is:

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

2.4 NORSEK D-010

The Petroleum sector went through difficult times in the 90s. The industry experienced a rise in cost, while the price of oil were on decline. Every company had their own set of standard usually based on different standards from the US. The US standards is also adapted to a different operational environment than the one on the NCS.

NORSEK were the result of the process of making a Norwegian standard. It is a collaboration between different actors in the oil industry and government. The purpose of the standard was to add value, increase safety and eliminate unnecessary operations in offshore field developments and operations. The NORSEK goal is to replace each company's individual specification and other guidelines for use in existing and future petroleum developments.

NORSEK D-010 Well Integrity in Drilling and Well Operations defines the minimum functional requirements and guidelines relating to well integrity drilling and well activities. NORSEK D-010 defines the requirements for establishing barriers and abandonment activities on the NCS. The most important chapter in NORSEK D-010 in terms of P&A are:

- Chapter 4.2- Well barrier principles.
- Chapter 9 – Requirements for Sidetrack, suspension and abandonment operations.
- Chapter 15- Well barrier acceptance criteria's for Well Barrier Elements (WBE).

2.4.1 Well barrier

A well barriers purpose is to stop unintentionally flow to the surface. The definition can be found in chapter 2.1. The well barriers **shall** be in place prior to any operation. It is done by identifying the required well barrier elements that is in place for that given operation. It takes one or several well barrier elements (WBE), which forms an envelope around the reservoir.

The NORSEK D-010 have different requirements for the number of barriers that has to be in place, depending on the source of in flow. There **shall** be two barriers in place when it is hydrocarbons in place or abnormal pressured formation. Table 1 illustrates this further. When there is two barrier in place a failure can occur without generating a leak to the surface.

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

Table 1-Minimum number of well barriers [4]

As mentioned above there has to be installed two well barriers to prevent flow to surface. The barrier closest to the reservoir is known as the primary barrier. In NORSOK it is defined as [4]:” *first well barrier that prevents flow from a potential source of inflow*”. The second barrier: “*second well barrier that prevents flow from a potential source of inflow and acts as a backup for primary well barrier*”. In figure 3 you can see that the primary well barrier is marked in blue and the secondary is marked with red. There **shall** also be an additional barrier: open hole to surface barrier. That barrier is also known as an environmental barrier. It is a “fail safe” barrier to isolate flow paths in the wellbore. The function of the environmental barrier is to permanently isolate flow conduits from exposed formations after the well is abandoned.

Well barrier schematic

It is stated in NORSOK that a well barrier schematic (WBS) **shall** be prepared for each well activity and operation showing different well barrier elements (WBE) in use. The purpose of the WBS is to show all the different WBE in use during an operation, and how they form an envelope against the reservoir. Figure 3 shows an example from Brage. It is easy to see which elements is a part of the primary barrier (blue) and which elements is part of the secondary well barrier. In order to have two different barriers a single WBE cannot be a part of both the primary and secondary well barrier. There are no rules without exceptions. For some well activities a common well barrier element is not avoidable. *When a common WBE exists, a risk analysis shall be performed and a risk reducing measure applied [4].*

It is stated in NORSOK when a WBS **should** be made [4]:

- a) “When a new well component is acting as a WBE;
- b) For illustration of the completed well with XT (planned and as built);
- c) For recompletion or workover on wells with deficient WBEs; and
- d) For final status of permanently abandoned wells.”

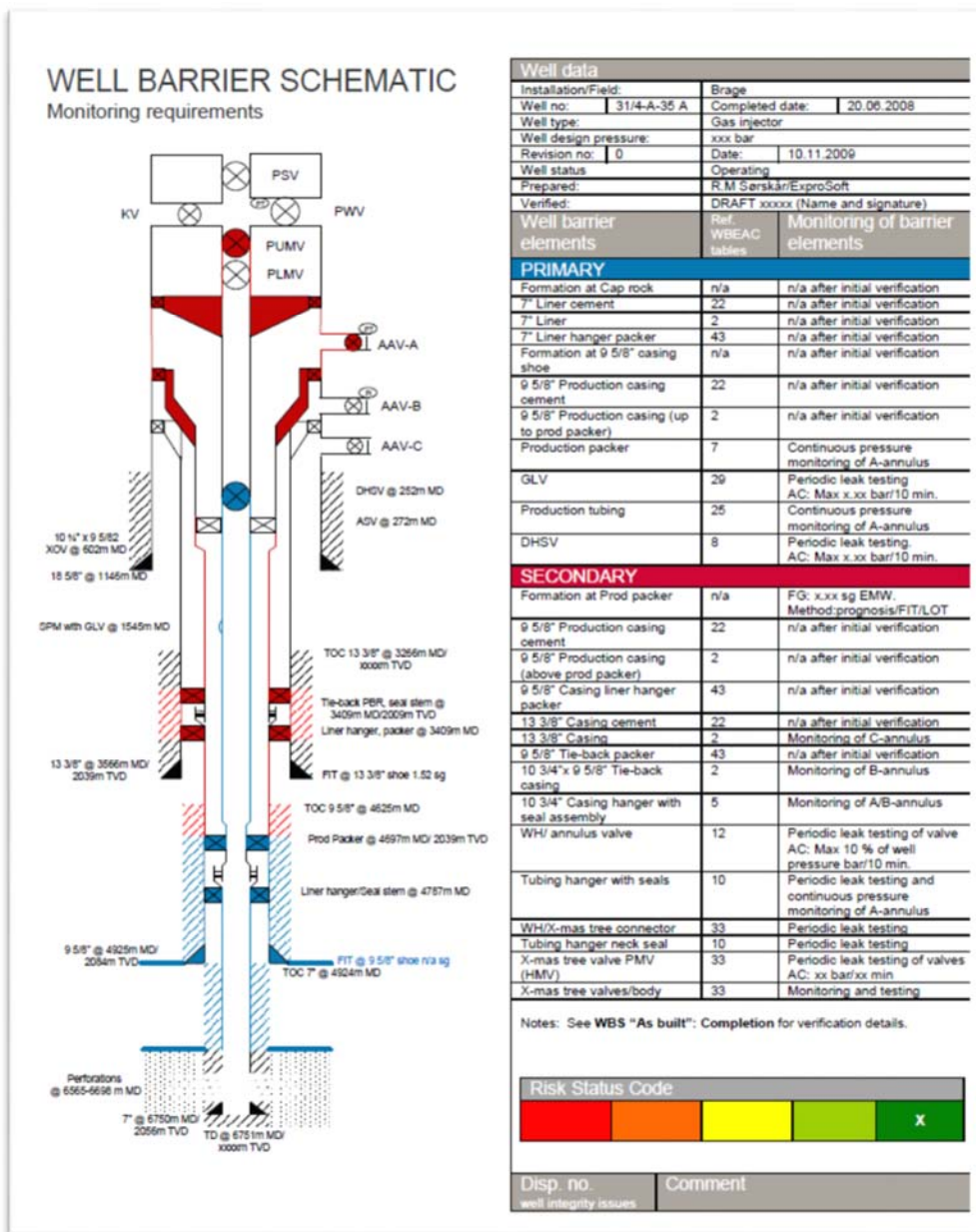


Figure 3- WBS from Brage [8]

The WBS from the oil companies is a lot more detailed than the ones in NORSOK. A piece of information that is part of both Schematics is Well Barrier Elements Acceptance Criteria (WBEAC). The WBEAC table can be found to the right of the table containing WBEs. The number refers to chapter 15 in NORSOK, containing all the acceptance criteria's. The acceptance criteria states the different specific technical and operational requirements and guidelines relating to WBEs that shall be applicable for all types of activities. Acceptance criteria 52 in NORSOK D-010 states the different criteria that has to be in place before using the given formation as permanent barrier, in this thesis the Hordaland green clay will be used as a permanent barrier to seal around the casing.

2.4.2 Permanent abandonment

Permanent abandonment is defined by NORSOK as: *“a well status, where the well is abandoned and will not be used or re-entered again”*. In NORSOK D-010 chapter 9 is related to permanent abandonment activities, and says: *“Permanently abandoned wells **shall** be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes”*. In other words the well **shall** be abandoned in a way so that a leak never will occur in the future.

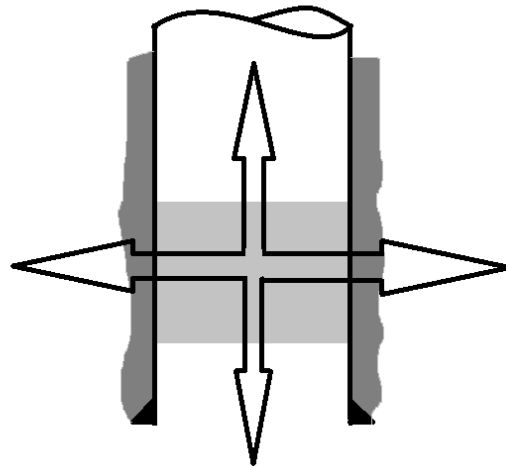


Figure 4- Permanent well barriers [4]

A well barrier can function as a shared well barrier for more than one wellbore. If there is two different reservoirs within a different pressure regime (cannot be seen as one reservoir) a cross flow well barrier is required between two reservoirs. In this case, the secondary barrier for the deepest reservoir can be used as the primary for the shallowest reservoir. A permanent

well barrier shall extend across the full cross section of the well. If the cement is verified in the wellbore, but there is poor casing cement outside, it is not qualified as permanent barrier. It is important that the formation is capable to withstand the maximum anticipated pressure below the plug. That is why the formation is listed in the WBS, as shown in Figure 3.

2.4.2.1 Permanent well barrier requirements

NORSOK does not say anything about what materials to use when plugging the well. They just list a number of physical requirements a permanent barrier **should** have in order to be verified as a barrier, and leave it up to the operator to choose the ideal material. A permanent well barrier **should** have the following characteristics [4]:

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

The suitability of the selected plugging materials shall be verified and documented. Cement is the most common permanent barrier because it fulfill the NORSOK requirements and is well proven. Degradation of the casing should be considered, when the casing is a part of a well barrier.

Downhole equipment has to be removed when it can form a potential leak path in the future. For example control lines and cables can cause loss of well integrity.

Positioning of well barriers

It is stated in NORSOK that the reservoir plugs **should** be placed as close to the source of inflow as possible, but **shall** be placed at a depth where the formation integrity is able to withstand the maximum pressure below the plug. In addition a permanent barrier should be set across the impermeable formation.

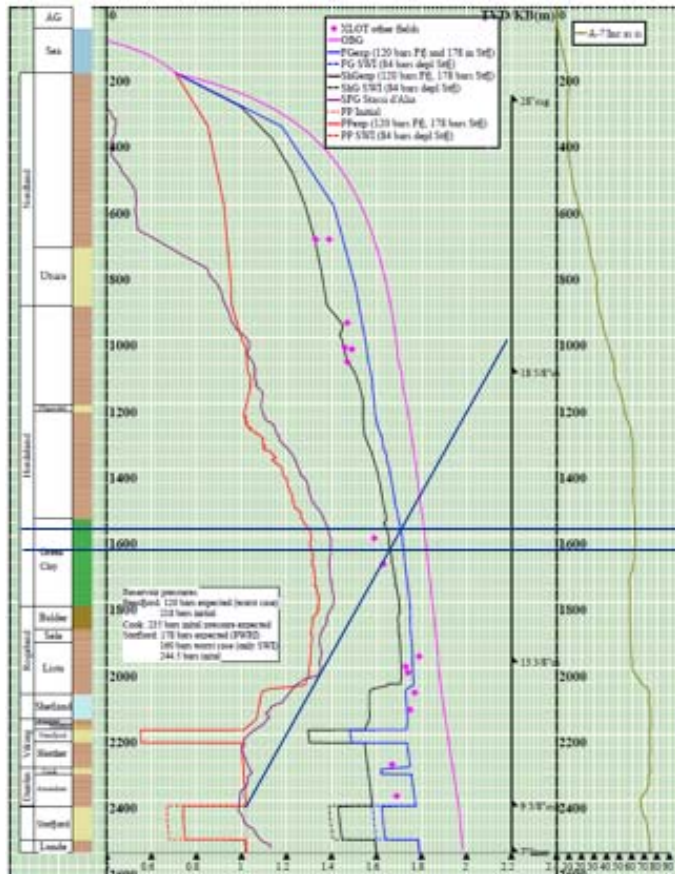


Figure 5- Minimum setting depth depending on the fracture pressure of impermeable formation. [9]

The base of the secondary barrier has to be set below the minimum setting depth where maximum potential pressure does not exceed formation fracture pressure. Common practice some years ago was to use the fracture gradient from a leak-off test or a formation integrity test. The procedures has changed in later years and the minimum horizontal stress achieved from an extended leak-off test is now being used. The secondary barrier shall be placed at a depth where minimum horizontal stress is higher than the potential pressure that can occur from below (Bottom hole pressure-hydrostatic pressure). The estimate in fig. 5 is very conservative, showing a gas gradient from Fensfjord which only contains oil and an oil gradient from Statfjord.

Length requirements of well barriers

NORSOK section 9.6.3.1 gives the requirements for external WBEs:

*The external WBE (e.g. casing cement) **shall** be verified to ensure a vertical and horizontal seal.*

The requirement for an external WBE is 50 m with formation integrity at the base of the interval.

If the casing cement is verified by logging, a minimum of 30 m interval with acceptable bonding is required to act as a permanent external WBE.

*The interval **shall** have formation integrity.*

*Logging of casing cement **shall** be performed for critical cement jobs and for permanent abandonment where the same casing cement is a part of the primary and secondary well barriers.*

*If sustained casing pressure is observed, the seal of the casing cement **shall** be re-verified [4].*

The requirements for internal WBEs is given in section 9.6.3.2:

An internal WBE (e.g. cement plug) shall be positioned over the entire interval (defined as a well barrier) where there is a verified external WBE and shall be minimum 50 m if set on a mechanical plug/cement as a foundation, otherwise according to EAC 24 [4].

An open hole cement plug **shall** have a 100 m MD with minimum 50 m MD above any source of inflow/leakage point. A plug in transition from open hole to casing **should** extend at least 50 m MD above and below casing shoe. For a cased hole cement plug with a mechanical/cement plug as a foundation the minimum length has to be 50 m MD. If the plug is not set on a foundation, the plug has to be 100 m MD. An open hole to surface plug is installed on a mechanical plug has to be 50 m MD, otherwise 100 m MD [4].

Abandonment of open hole with cement plugs

The abandonment of an open hole using a cement plug is done by setting a 100 m cement plug across/above the reservoir. The primary cement plug has to extend for a minimum 50 m above the reservoir/leaking point. The length of the secondary cement plug should extend 50 m below the shoe and 50 m inside the casing. The external requirements are 50 m of cement behind casing, 30 if verified by logging.

The requirements states that the formation has to have sufficient formation integrity at the base of both well barriers to withstand maximum expected pressure from the formation [4].

Back-to-back cement plugs and logged casing cement

The last open hole section of a wellbore or perforated casing/liner is done by setting a back to back cement plug against the reservoir, bullhead cement into the reservoir. In order for this to be accepted as a permanent solution, there are certain criteria's. The primary barrier has to be 100 m, 50 meters below casing/liner shoe and 50 m internal with 30 m of verified cement behind casing. Provided that the casing cement is verified. The secondary barrier is placed on top of the primary, and consist of 50 m verified cement internal, with 30 m of verified cement behind casing [4].

Single cement plug in combination with mechanical plug

The abandonment in this case is done by using a mechanical plug as a foundation for the single cement plug. The single cement plug act both as a primary and a secondary barrier. In order to be accepted as a permanent barrier the cement plug needs to be pressure tested and tagged. The mechanical plug which is used as a foundation for the cement plug is pressure tested and there are therefore no reason to pressure test the plug later. When the cement is set, it is tagged by drilling out cement until we reach hard cement. External cement or formation has to be 2*50m and 2*30m if verified by logging [4].

Tubing stump left in hole

In this example the primary barrier is set above the reservoir in the liner with 50 m cement on the outside and inside. It is expensive to pull the tubing so it be beneficial to leave the tubing in hole. When leaving the tubing in hole it is important that there is not any control lines part of the permanent abandonment. Oil and Gas can escape along the flowlines. When completion tubulars are left in the well the casing cement between the casing and tubing **shall** be verified by pressure testing. The cement plug inside tubing **shall** be tagged and verified. The A-annulus is verified with pressure test. [4]

2.4.2.2 Verification of well barrier elements

The requirements for verification of WBE can be found in section 4.2.3.5 [4]

When a WBE has been installed, its integrity shall:

- a) Be verified by means of pressure testing by application of a differential pressure; or*
- b) When a) is not feasible, be verified by other specified methods.*

Well barrier elements that require activation shall be function tested.

A re-verification should be performed if:

- c) The condition of any WBE has changed, or;*
- d) There is a change in loads for the remaining life cycle of the well (drilling, completion and production phase).*

Verification of Internal WBE

The internal barriers is usually made up of cement. Cement is a well-used material, due to the fact that it is cheap, easily accessible and it satisfy the requirements stated in NORSOK [4]:

The cement plug in the wellbore needs to be verified in order to make sure it can withstand the differential pressure that might occur. Acceptance criteria for cement plug states the following requirements for verification of a cement plug:

- Cased hole **should** be tested in the direction of the flow, if that is not possible it can be tested against the flow.
- The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
- An open hole plug shall be verified by tagging. Cannot perform a positive pressure test due to risk of fracturing the formation.
- Cased hole plug shall be verified by tagging. It shall also be pressure tested with two requirements:
 - a) be 70 bar (1000 psi) above estimated leak off pressure (LOT) below casing/ potential leak path, or 35 bar (500 psi) for surface casing plugs;
and
 - b) Not exceed the casing pressure test and the casing burst rating corrected for casing wear.
- If the cement plug is set on a pressure tested foundation, a pressure test is not required. It shall be verified by tagging.

Verification of casing cement

Casing cement has to be verified in order to qualify as a WBE. It is stated in the acceptance criteria that the casing cement **shall** be verified, either by logging or based on records from the cement operation volumes pumped, returns during cementing, etc. The cement sealing ability shall be verified through a formation integrity test when the casing shoe/window is drilled out.

2.4.2.3 Removing equipment above seabed

When the environmental barrier has been set it is important to remove the equipment above seabed, just in case it does not interfere with other activities. NORSOK state the following [4]:

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

3 Plug & abandonment

The purpose of this section is to give an overview of the P&A operation. Chapter 2 gave an introduction to the regulations, this section go through the operational sequence and challenges related to P&A on NCS.

3.1 P&A in Norway

The Norwegian oil adventure started in 1969 when ConocoPhillips discovered the Ekofisk field. It was put in production in 1971. In the years that followed fields like Statfjord, Gullfaks, Oseberg and Troll came into production.

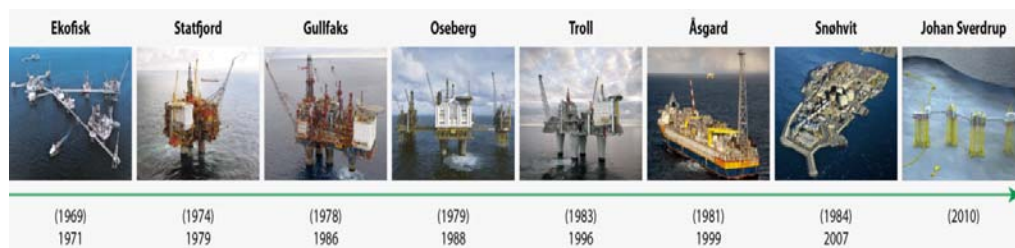


Figure 6-Historical timeline of NCS [10]

There is a lot of fields on the NCS that has produced for several decades and are now experiencing a decline in production rates. When a field is no longer economical, it is time to decommission the field. The industry is now facing what by some people is referred to as a “Plug Wave”. It has been a growing focus on P&A, because of the high cost and the number of wells that are soon to be plugged.

According to a presentation given in PAF seminar, there are 2545 wellbores on NCS that needs to be plugged [11]. With the solutions available today, it would take 15 rigs 40 years to permanently P&A all these wells on the NCS [12]. Using the current rig rates it will cost approximately 876 billion NOK [12]. 876 billion is the equivalent of 57 % of the Norwegian national budget in 2014. 22 % of that expense will be paid by the licenses the rest will be covered by the Norwegian state [12].

It is reason to believe that 30 % of the cost related to P&A can be saved [12]. The technology development within oil recovery and subsea installations has been a Norwegian success story, but the P&A technology has not been experiencing the same development. That is the reason why the plug & abandonment forum (PAF) was

established in 2009 to promote development of solutions to current and upcoming P&A challenges in the North Sea.

3.2 Phases of well abandonment

Oil and Gas United Kingdom (O&G UK) Guideline on Well Abandonment Well issue divide P&A operation into three different phases to indicate the work scope. Oil and gas UK Guideline on Well Abandonment Well issue has separated between reservoir abandonment, intermediate abandonment and WH and conductor removal [13].

Phase 1: **Reservoir Abandonment**

The reservoir abandonment phase involves setting a primary and secondary permanent barrier to completely isolate all producing reservoirs or injector zones from the wellbore. The tubing may be left in place, partly or fully retrieved.

Phase 2: **Intermediate Abandonment**

The second phase involves the following operations: isolating liners, milling and retrieving casing, and setting barriers to intermediate hydrocarbon or water bearing permeable zones. The tubing may be retrieved if not done in Phase 1. This phase is complete when no further plugging is required.

Phase 3: **Wellhead and conductor removal**

The last phase includes; retrieval of wellhead, conductor, and shallow cuts of casing string and cement filling of craters. This phase is considered finished when no further operations required on the well.

3.3 Traditional Brage Plug & Abandonment:

The P&A operation can vary depending on the different casing design. There is a lot of factors that will change the well design: top of cement, multiple reservoirs, geology, type of well etc., and this will affect the P&A operation. The purpose of this section is taking the reader through the main steps in a P&A operation. Each step will be different due to various well design. For example pulling of the tubing will be more time consuming for a gas lift well, because it will require extra work in order to release the Annular safety valve (ASV).

There are 40 wells on Brage, and the permanent P&A solution will vary quite a bit. Depending on the depth of the 18 5/8 “, if the casing shoe for the 18 5/8” is deeper than the Green clay formation, the 13 3/8 “ needs to be pulled before placing the dual barrier plug. There are four shallow wells, which goes into the Oligocene sand and the Utsira formation. The operation will change from one well to another, but the principal is the same.

Well diagnostic

In a hospital, they do not operate without setting a diagnose. The same rule applies for a well, it is important to know the condition of the well and plan the operation beforehand. There are a lot of old wells on the NCS. The original well design is given but a lot of these old wells was established without thoughts regarding P&A. The well design form the basis of the P&A design. [14]

Kill the well

Before entering a live well, the well needs to be taken under control. This is usually done by bullhead fluid into the well. One of the most common methods is to pump brine, and force the production fluids back into the reservoir. The injection rate must be large enough to push the fluid back into the well (larger than WH pressure)[15].

Install Deep Set Plug

Install a mechanical plug deep in the well to function as temporary barrier against the reservoir. The plug is inflow and pressure tested [15].

Punch and release ASV and displace well to brine

Gas lift is often used to extend the life time of a well. In wells with gas lift an annular safety valve (ASV) is installed. The ASV needs to be released in order to pull the tubing [15].

Cut tubing Displace well to Brine

The tubing is cut a few meters above the packer, before pulling the tubing out of the hole. The well is circulated to brine [15].

Install Shallow Set Plug

It is common to install a shallow plug below the DHSV as a well barrier element. The plug is installed to have two barriers against the reservoir as stated in NORSOK D-010. The barriers needs to be verified by a pressure test. The wireline is rigged down after this operation.

The steps above are done by the intervention department. After the shallow barrier plug is installed, the well is handed over to the drilling & wells department, and they permanently P&A the well. There are a lot of different well designs on Brage and the operation will vary from one well to another but in general it means pulling the tubing/casings and setting sufficient barriers in the well. The general operation steps will usually be done in the following manor [15]:

- **Nipple down X-mas Tree**

Nipple down x-mas tree and prepare wellhead prior to nipple up riser and drilling BOP.

- Barriers:
 - Deep Set plug in Tubing
 - Shallow set plug in Tubing

- **Nipple up BOP and riser**

Nipple up riser and Bop to ensure well control and access to the well. Test BOP connection against shallow plug.

- Barriers:
 - Deep Set plug in Tubing
 - Shallow set plug in Tubing

- **Pull shallow plug**

Run into hole with wireline and latch onto plug at ~60 m, release plug and pull out of hole.

- Barriers:
 - Fluid Column and deep plug
 - 13 3/8 " Casing, Wellhead and BOP

- **Pull upper completion string**

Pull completion from PBR/ Tubing cut (done in the intervention part). Pull the tubing with the tubing hanger retriever tool.

- Barriers:
 - Fluid Column and deep plug
 - 13 3/8 " Casing, Wellhead and BOP

- **Clean out run 9 5/8 " casing**

The objective of this operation is to remove debris within the casing and displace to an overbalanced fluid for P&A operation. If unable to clean out the well sufficiently will ruin the USIT and CBL log.

- Barriers:
 - Fluid Column
 - 13 3/8 " Casing, Wellhead and BOP

- **Log 9 5/8 “ with USIT/CBL**

When plugging the well permanently it is important to seal across the entire cross-section of the well. Therefore the cement behind the casing needs to be verified by logging. Logs are run into the well to make sure the formation or cement has good bonding to the casing.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP
 - Hydraulic wireline cutter required

- **Set a mechanical plug as base for cement plug**

A mechanical plug is set to form a base for the cement plug to be placed. The plug needs to be pressure tested in order to be accepted as a barrier.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP

- **Set 9 5/8 “ cement plug**

Set a permanent barrier against the reservoir, the plug acts as a primary permanent barrier. The sequence is done by running in hole with cement stinger, the length of the plug is +/- 200 m. If the mechanical plug has been pressure tested it is no need to pressure test the cement plug. After the plug is set, it is tagged with 10 tonnes. The string is rotated with a low rpm to check for increase in torque.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP

- **Remove Tubing Head**

After the 9 5/8 “ plug has been pressure tested and verified the tubing head has to be removed in order to pull the 9 5/8 “ casing. Before removing the Tubing head a shallow barrier plug is placed in order to have two barriers against the reservoir. Tubing head is removed and the shallow barrier plug is pulled.

- Barriers:
 - Cement plug
 - Shallow set mechanical plug, 13 3/8 “ Casing, Wellhead and BOP

- **Cut and pull 9 5/8 “ casing**

The secondary barrier plug is set against the green Clay which is proven to have good bonding to the formation. It is not possible to verify the cement behind multiple casings, then the 9 5/8 “ casing has to be cut and pulled.

The operation starts by making up cutter assembly and run in hole to desired depth. When the casing has been cut the cutter bottom hole assembly is pulled out of the hole. The casing is free and will be pulled out of the hole with spear assembly.

- Barriers:
 - Cement plug
 - Fluid Column/ Casing, Wellhead and BOP

- **Clean out run 13 3/8 “**

The objective of this operation is to remove debris within the casing and displace to an overbalanced fluid for P&A operation. If unable to clean out the well sufficiently will ruin the USIT and CBL log.

- Barriers:
 - Cement plug
 - 13 3/8” Casing, Wellhead and BOP

- **Log 13 3/8 “ with USIT/CBL**

When plugging the well permanently it is important to seal across the entire cross-section of the well. Therefore the cement behind the casing needs to be verified by logging. Logs are run into the well to make sure the formation or cement has good bonding to the casing.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP
 - Hydraulic wireline cutter required

- **Set a mechanical plug as base for cement plug**

A mechanical plug is set to form a base for the cement plug to be placed. The plug needs to be pressure tested in order to be accepted as a barrier.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP

- **Set 13 3/8 “ plug**

Set a permanent barrier against the reservoir, the plug acts as a primary permanent barrier. The sequence is done by running in hole with cement stinger, the length of the plug is +/- 200 m. If the mechanical plug has been pressure tested it is no need to pressure test the cement plug.

When P&A is planned in this thesis, a dual plug is placed in the green clay, assume that the formation has good bonding in all the wells. When a dual plug is planned, the plug needs to be dressed off in addition to tagging with +/- 10 tones.

- Barriers:
 - Fluid Column
 - 13 3/8 “ Casing, Wellhead and BOP

- **Cut and pull 13 3/8 “ casing**

Cut and pull the 13 3/8 “ casing and pulled to required depth in order to place an environmental plug.

- Barriers:
 - Fluid Column
 - 18 5/8 “ Casing, Wellhead and BOP

- **Clean up run in 18 5/8” casing**

Remove any debris after cutting the casings and prepare for running wireline in hole. Prepare setting area for 18 5/8 “ bridge plug.

- Barriers:
 - Fluid Column
 - 18 5/8 “ Casing, Wellhead and BOP

- **Log 18 5/8” casing**

The 18 5/8 “ logging tool is run to find out if the cement behind the casing is good enough to act as a permanent barrier. Not necessary if casing is cemented to the top.

- Barriers:
 - Fluid Column
 - 18 5/8 “ Casing, Wellhead and BOP
 - Hydraulic wireline cutter may be required during logging

- **Set environmental plug**

When casing cement is of good quality, it is sufficient to place the environmental plug inside the casing.

- Barriers:
 - Fluid Column
 - 18 5/8 “ Casing, Wellhead and BOP

- **Retrieve wellhead**

The last part of permanent P&A is cutting and retrieving of the wellhead.

NORSOK D-010 states that the wellhead shall be removed below the seabed at a depth that ensures no protrusion in the future. Required cutting depth shall be sufficient to prevent conflict with other marine activities, and local conditions such as soil and seabed scouring due to sea current should be considered. In deep-waters, with water levels deeper than 600 m it may be sufficient to leave or cover the wellhead.

3.4 Challenges of P & A operations in the North Sea

P&A operation is technically-challenging, time-consuming and involves high-cost operations. This chapter will address some of the challenges that can occur when working on such technical-challenging operation:

3.4.1 Weather

Weather is always a challenge for any operation offshore. In rough sea, tasks like logistics, mobilization and operation depends on the weather conditions. Weather becomes a smaller issue when the operation is done from a fixed installation like Brage, rather than floating vessels semi-submersible or Light Well Intervention Vessel (LWIV). Waiting on weather can add a lot of extra cost to an operation. Studies done by Valdal showed that LWIV have more WOW than a modular rig, due to the size and structure of the vessel. [16]

3.4.2 Knowledge of well situation

There are many wells on the NCS that are ready to be decommissioned. The majority of these wells were drilled in the 80s. The technology available at that time was not of the same standard, compared with what is available today. The data is usually found in the form of paper hard copies or scanned documents [17].

Some of the wells on NCS are almost half a century old. The material properties of the well is not what they used to be, due to corrosion and wear. There can be leaking elements or mechanical obstructions. Many of the well has been suspended or temporary abandoned and the status of the wells are unknown.

The biggest uncertainty is usually the quality of the cement behind the casing. In order to establish a permanent barrier, there shall be a sealing cross section. If the casing cement does not provide good bonding/isolation between the casing and the cement, it cannot be a part of a permanent barrier.

In the overburden at Brage we got a formation which consists of creeping shale. It has been proven that this formation creates good bonding with the casing in the wells at the Oseberg

field, the green clay at Brage field has the same Mineralogy. The bonding has to be proven for every well, in the same way as cement.

3.4.3 Milling

As mentioned earlier a permanent plug has to be sealing over the entire cross section of the well. In many cases the cement is often of poor quality or none existing. In order to place a plug across the entire cross section of the well, a casing window can be opened. The conventional way to do this is to section mill the required length of the casing. Then perform a clean-up run and under ream the open hole and place the cement plug [18].

Section milling is a complicated process. Some of the main problems are listed below:

- Open hole exposure- When milling, the formation will be exposed and therefore it is important to have the right fluid properties, close to the average between pore pressure and fracture pressure.
- Milling fluid and hole cleaning- It is important that the milling fluid has sufficient viscosity to get the heavy and dense swarf objects out of the hole. Unable to get swarf out of the hole will generate pack-off.
- Damaging BOP- Section milling generates a lot of swarf which are very sharp objects. This sharp objects can damage the ram and annular seal inside the BOP.
- Vibration- the milling assembly is subjected to a high level of vibration, which can damage BHA and cause reduction of ROP
- Swarf handling- Milling an entire section generates a lot of swarf, which is hard to handle on deck, but most of the swarf remain in the hole and can cause problems when entering the well.

3.4.4 Cutting and removal of casing

In order to place the cement plug, it is necessary to remove the casing to seal the entire cross section. It is a very technically challenging procedure. The casing can easily be stuck due to old cement and settled particles behind the casing. Then it can necessary to perform a cut and pull operation multiple times to get the casing out of the hole, or section milling.

3.4.5 Removal of control lines

Leaving the tubing in hole could potentially save a lot of money, because most wells on the NCS have control lines or cables attached along the tubing to monitor and control the wells. Control lines cannot be a part of a permanent P&A solution because hydrocarbons can leak alongside them. In order to remove the control lines, the tubing needs to be pulled out of the hole, which is an operation that needs heavy duty equipment. If the tubing could be left in hole it could potentially save a lot of money for the operators [4].

3.4.6 Log cement through multiple casings

Casing cement has to be verified if it is going to be a part of a permanent well barrier. The common method to verify casing cement are logging. The technology currently available is not capable of logging through multiple casings. Therefore all the inner casing has to be removed to get access for logging, and verify the entire cross section.

4 The Brage field

The Brage field was discovered in 1980 by Hydro. The field is located on Blocks 30/6, 31/4 and 31/7, 125 km west of Bergen. First oil on deck was produced as early as 1993. Statoil took over as operator from in 2009 until Wintershall took over in 2013. The field is owned by Wintershall Norge AS (Operator, 35, 2 %), Repsol Norge AS (33, 9 %), Faroe Petroleum Norge AS (14, 3 %), Point Resources AS (12, 2 %) and VNG Norge AS (4, 4 %)[19]. The six first wells were pre drilled by a semi-submersible rig, Vildkat explorer. The remaining wells were drilled from the Brage platform. In 1998 the Brage field had a plateau rate at 120 kbbl/d. The production has decreased over the years and is now currently at 12 kbbl/d [19].

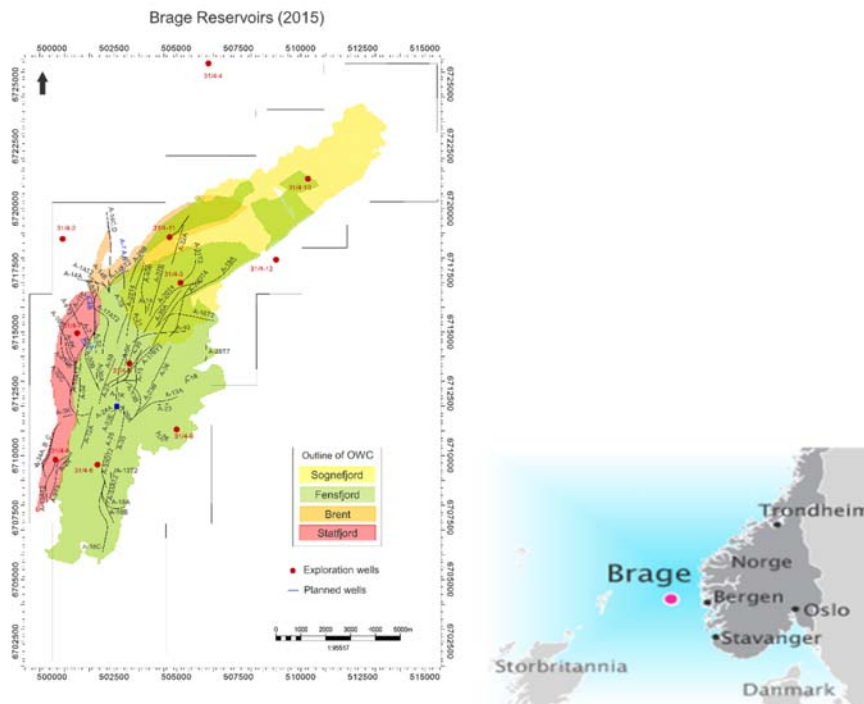


Figure 7 Location and overview of the Brage field [9]

Brage is a combined oil and gas field and it was initially estimated to contain 157, 8 mill Sm³ of oil [20]. The field consists of 40 wells. 6 wells were drilled before the Brage platform was in place. The jacket/platform was in place in 1993. The 6 pre-drilled wells were tied-back to surface. In 1993 there were installed 10 curved and 18 straight conductors. The platform wells was drilled later the same year. The 6 remaining conductors came in 1996 and the conductor were installed afterwards.

4.1 Geology

The Brage field is located in the North Sea 120 km northwest of the city of Bergen. It is located 13 km to the east of the Oseberg Field Center, the location is shown in Figure 7. The field is located on the Horda Plateau, on the east side of the Viking graben. There were drilled an exploration well in 1980 (31/4-3) the primary objective were sandstone within the early Jurassic Dunlin and Statfjord formation. The sandstone reservoirs is made up of rocks from early to middle Jurassic. The field produces from four different reservoirs: Statfjord, Fensfjord, Sognefjord and Brent [21].

All the formations in the overburden at Brage Nordland, Hordaland and Rogaland are fairly uniform and consists of fairly uniform shale. There are two overlying permeable zones, Utsira sand and Oligocene sandstone. Other than that the overburden consist of shale with varying competency. Utsira, Oligocene and Hordaland are of special interest for this thesis, and are presented below [21]:

Group	Formation	Approx Fm tops
Nordland		
	Utsira	717 - 728
Hordaland		900
	Oligocene	1175 - 1239
	Green clay	1491, 1510
Rogaland	Balder	1804 - 1882
	Sele	1853 - 1922
	Lista	1890, 1939

Figure 8: Overview of the Brage overburden [21]

Utsira

The Utsira formation is generally encountered at approximately 700 m TVD and can extend down to 900 m. Consists of clear, occasionally milky white, fine to coarse grained quarts, lose sand. The formation is normally pressured [21].

Oligocene

Oligocene is encountered around 1200 m. It is partly cemented sand. There is a normal gradient down to the bottom of the Oligocene sand [21].

Hordaland Green Clay

The green clay in the Hordaland is usually encountered at around 1500 m TVD and has a thickness of approximately 300 m, and is located in the lower part of the Hordaland formation. It is a creeping formation with plastic/ductile behavior. During drilling through this formation there have been tight hole problems, and there is a ~12 days window for running casing [21].

4.2 Reservoir

The Brage field consists of 4 different reservoirs: Statfjord, Fensfjord, Sognefjord and Brent. Figure 9 gives an overview of the Brage field and the different reservoir, which are overlapping. Sognefjord is the shallowest reservoir located at approximately 2000 m and deepest reservoir is Statfjord with top of formation at approximately 2330 m. The two other formations Fensfjord and Brent /Ore has a top of formation at 2080 and 2240 respectively [21].

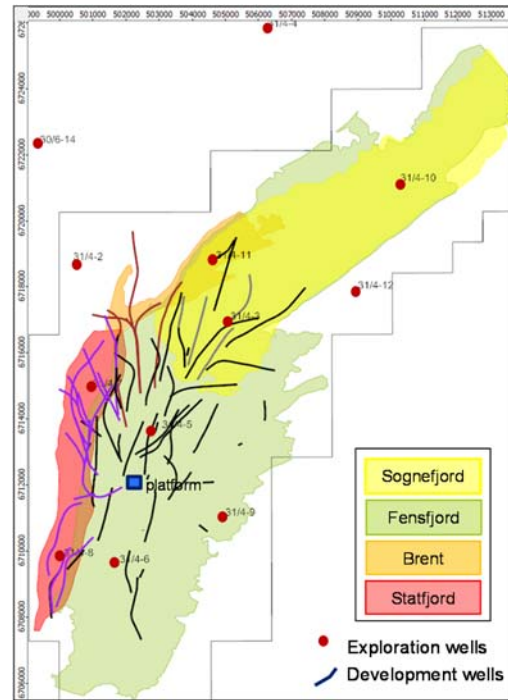


Figure 9-Overview Brage reservoir [21]

As shown in Figure 10; Statfjord and Fensfjord formation are the two biggest reservoirs. A short description of the different reservoirs will be given below [21]:

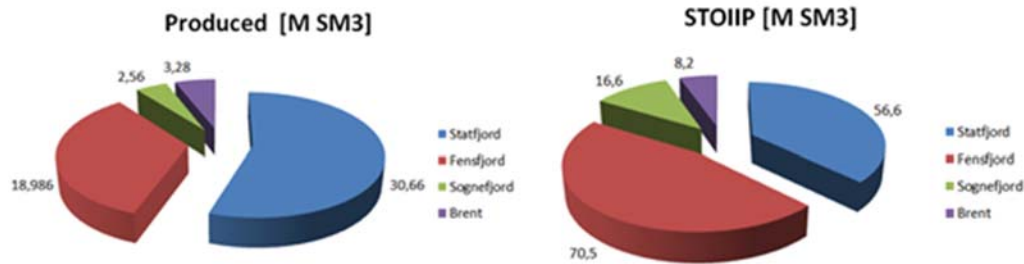


Figure 10-production from the different reservoirs at the Brage field [21]

4.2.1 Statfjord

The Statfjord group is from early Jurassic, the reservoir is formed by a braided river system. The reservoir quality is very good and very from continental to shallow marine sediments. There are two different compartments in this reservoir and it is being produced with shallow horizontal producers and one injector in each compartment.

4.2.2 Fensfjord

The Fensfjord is made up by deposits from middle Jurassic, and the sediments comes from middle shore face deposits. The reservoir quality range from poor to medium reservoir quality and has the largest STOIP among all the Brage reservoirs. The Fensfjord formation is a complex formation and heterogeneous due to faults and varying properties.

Developed with water injection, the producers are placed in the center, while injectors are placed on the flanks.

4.2.3 Sognefjord

The Sognefjord formation is made up by deposits from upper Jurassic, the depositional system is upper /middle shore face deposits. Produced with depletion, strong aquifer and initial gas cap.

4.2.4 Brent

The Brent was discovered in 2001, and consist of Upper Ness channels and ORE (Oseberg, Rannoch, Etive), the geological age is from the middle Jurassic. First well drilled in 2008, developed with water injector.

4.3 Brage platform



Figure 11- Brage Platform [22]

The Brage platform was online in 23.09.1993 and has an estimated lifetime until 2030. The water depth is 137 m, and 199 m up to bore deck. Brage is a fully integrated platform with living quarter, auxiliary equipment module, process modules, drilling modules, well and manifolds areas. The living quarter has cabin capacity of 130 people.

The oil is exported to the nearby Oseberg field, and then transported further with Oseberg Transport System (OTS) to the Sture-terminal. A gas pipe connects the platform to Statpipe, and transports the gas to Kårstø [22].

5 Plug & Abandonment procedures on Brage

The Brage field consists of 40 different wells. As a consequence, there are many different casing designs. The purpose of this chapter is to categorize the different wells at Brage.

It became evident quite early that the main category would be: pre-drilled wells, Simplified casing design and wells with a production liner and tie-back casing. In addition there are four wells that target shallower formation like the Oligocene and Utsira sand. There are also a group of wells where it was not beneficial to place the plug against the Hordaland green clay, due to risk of stuck casing.

The pre drilled wells were drilled before the platform was moved to location. The internal conductor makes it extra difficult to P&A the wells, it is necessary to change the conductor with an external conductor in order to pull the 9 5/8" casing. Cross sectional schematics of the internal and external conductor can be found in Appendix A.

The largest group is the one with a production liner and a tie- back casing. These wells require pulling of the tie-back casing before setting the primary and secondary barrier.

Wells with simplified casing design has a dummy 18 5/8" casing, which does not even extend down to sea bottom. These wells does not require pulling of casing before setting the dual barrier plug.

Logs done by Wintershall has shown that the green clay forms good bindings to the casing. We assume good bonding in all the wells at Brage. In this thesis all the plugs will be set against this formation, except for wells where stuck casings might be a problem, these cases are discussed in depth in chapter 5.5. The cement plug will be set inside the 9 5/8" below the 13 3/8" shoe for these wells.

There will be placed a dual plug as primary & secondary barrier in all these wells, as shown in chapter 2. NORSOK states that the barrier **should** be placed as close as possible to the reservoir because of well integrity purposes. As mentioned earlier in the thesis this is a suggestion the barrier can be placed higher up in the well, if the formation is capable of withstanding the pressure.

The minimum setting depth will not be calculated in order of minimizing the scope of the study. At Brage there are different reservoirs with different virgin pressure. Therefore, assume

sufficient strength in the Hordaland formation. In well A-15 the secondary barrier is placed at the same depth as the dual barrier plugin this thesis. Therefore, it is a reasonable assumption.

The green clay formation is located at approximately 1500-1800 m TVD, but the measured depth will vary with the well path. As a result of this the measured depth of a formation can vary a lot from one well to another. In order to simplify the thesis the base of Hordaland green clay is set at 2500 m MD.

In the following chapter the different categories will be presented with:

- Short description of each category.
- Proposal for permanent P&A of these wells.
- Sketches of every well at Brage with the specific casing design (As is and after P&A.)
 - Some wells might differ from the given proposal, because of short 18 5/8" casing or completed without ASV. This will be pointed out below the sketch.

5.1 Pre-drilled wells

The first six wells on Brage was pre-drilled before the platform were in place. They were then tied-back from the seabed to the platform. All the casings are hung of in the subsea hanger and tied back with an internal tie-back conductor system. As a consequences of this design, it is necessary to change the conductor before pulling the 9 5/8" casing. This makes the slot recovery (except for 9 5/8" sidetracks) and P&A operation more complex [9].

Well A-1 changed to an external tie-back conductor, when it was sidetracked in 2008. A-1 is now categorized as a well with production liner and tie-back casing. The wells A-2 to A-6 will use the same method as A-1 to get access to the entire well.

5.1.1 Permanent Plug & abandonment proposal for pre-drilled well

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor
- Pull upper completion. From DHSV to cut (+/-2500 m MD)
- Remove tubing head
- Set shallow 9 5/8" barrier plug below seabed
- Cut 10 3/4" tie back casing at 50 m MD and POOH
- RIH and release and recover remaining 10 3/4" tie-back string from seabed
- Cut 13 3/8" tie-back at 50 m MD and POOH
- RIH and release and recover remaining 13 3/8" tie-back string from seabed
- Pull tie-back conductor with internal wellhead latch from seabed
- Run tie-back conductor with external wellhead latch to seabed
- Retrieve shallow plug
- Log 9 5/8" to verify bonding between casing and formation
- RIH with mechanical plug and pressure test
- Set dual cement plug, primary and secondary barrier
- Tag cement
- Cut and Pull 9 5/8" shallow
- Cut and pull 13 3/8" shallow
- Set mechanical plug and pressure test
- Set environmental plug
- Tag plug
- Remove conductor and casing strings a few meters below seabed

5.1.2 Sketches for pre-drilled wells

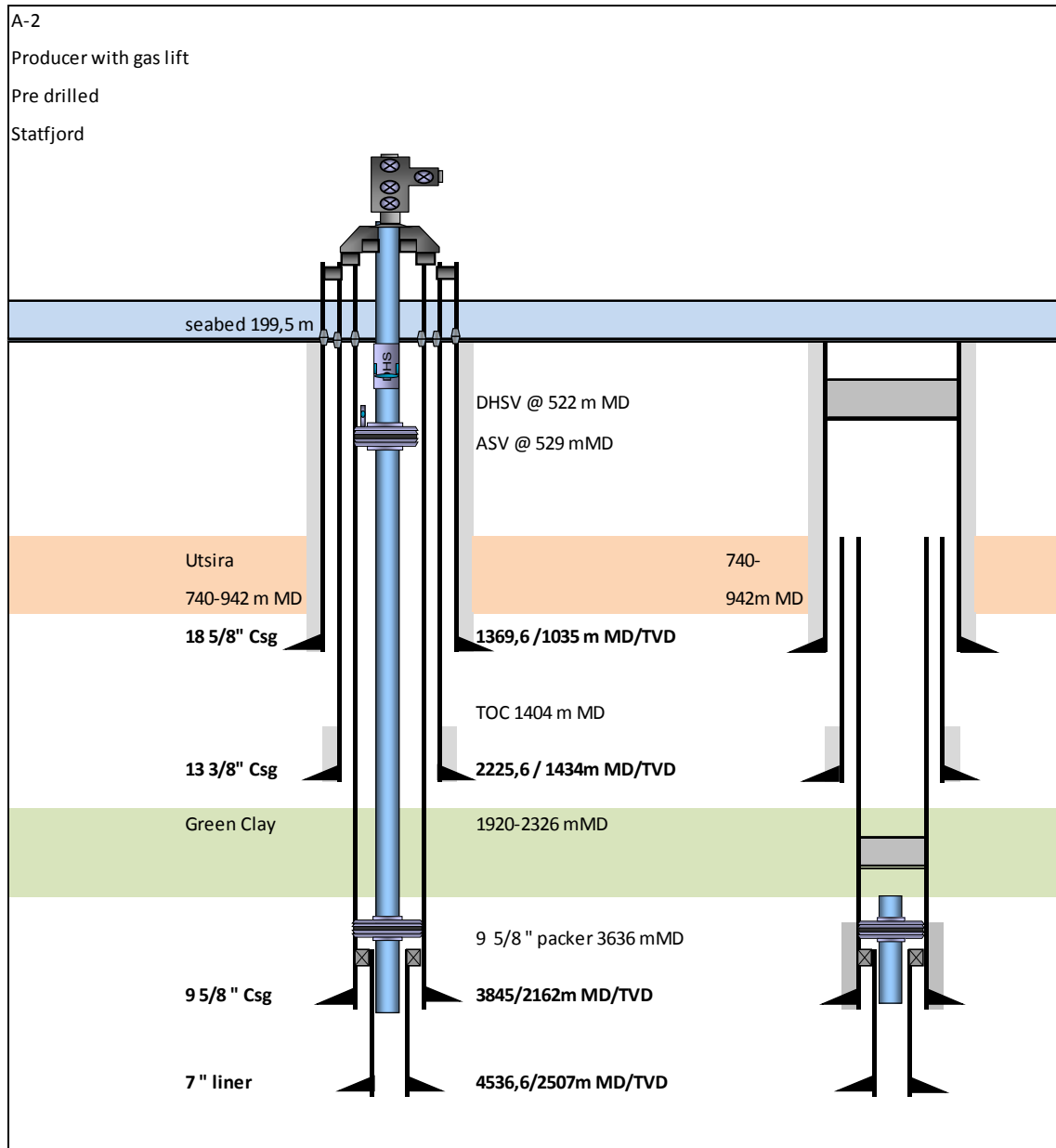


Figure 12- Pre-drilled well A-2

Reference 5.1.1

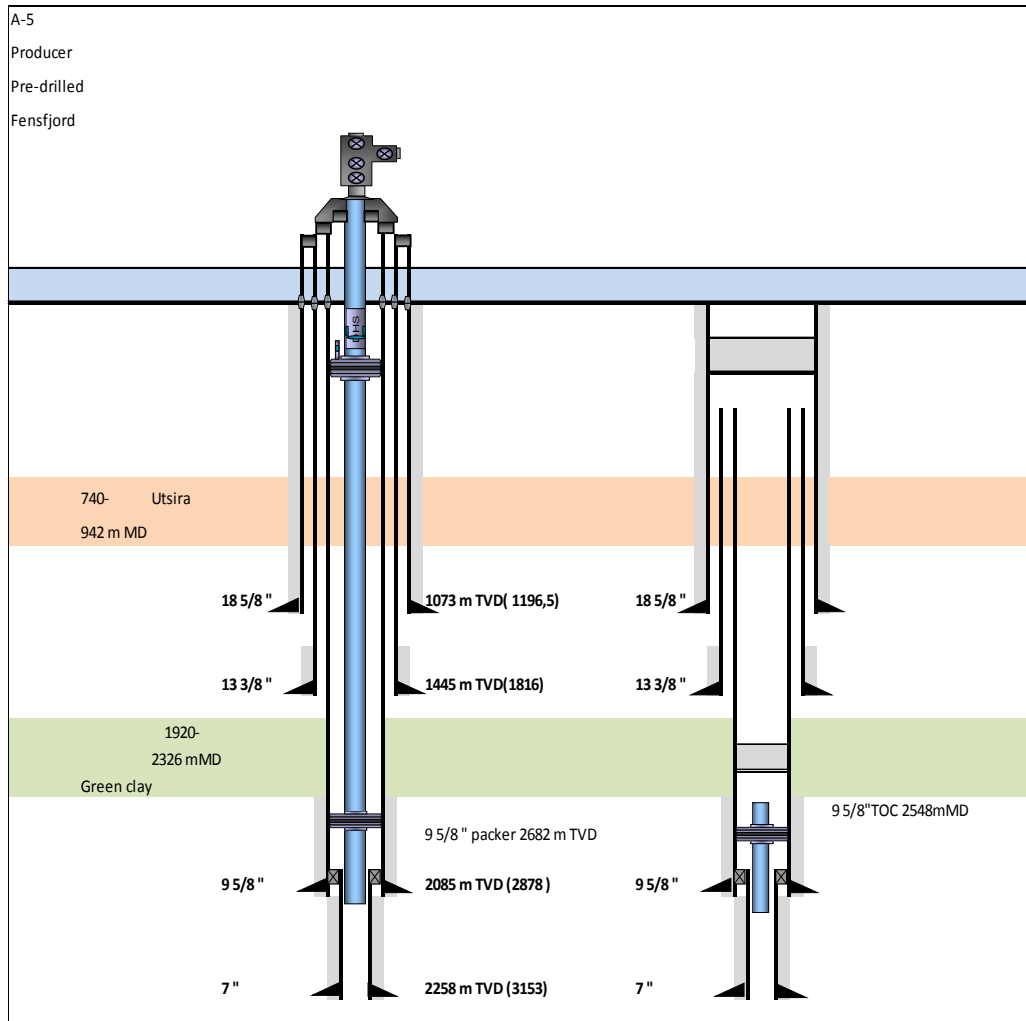


Figure 13: Pre-drilled well A-5 Producer

Reference: 5.1.1

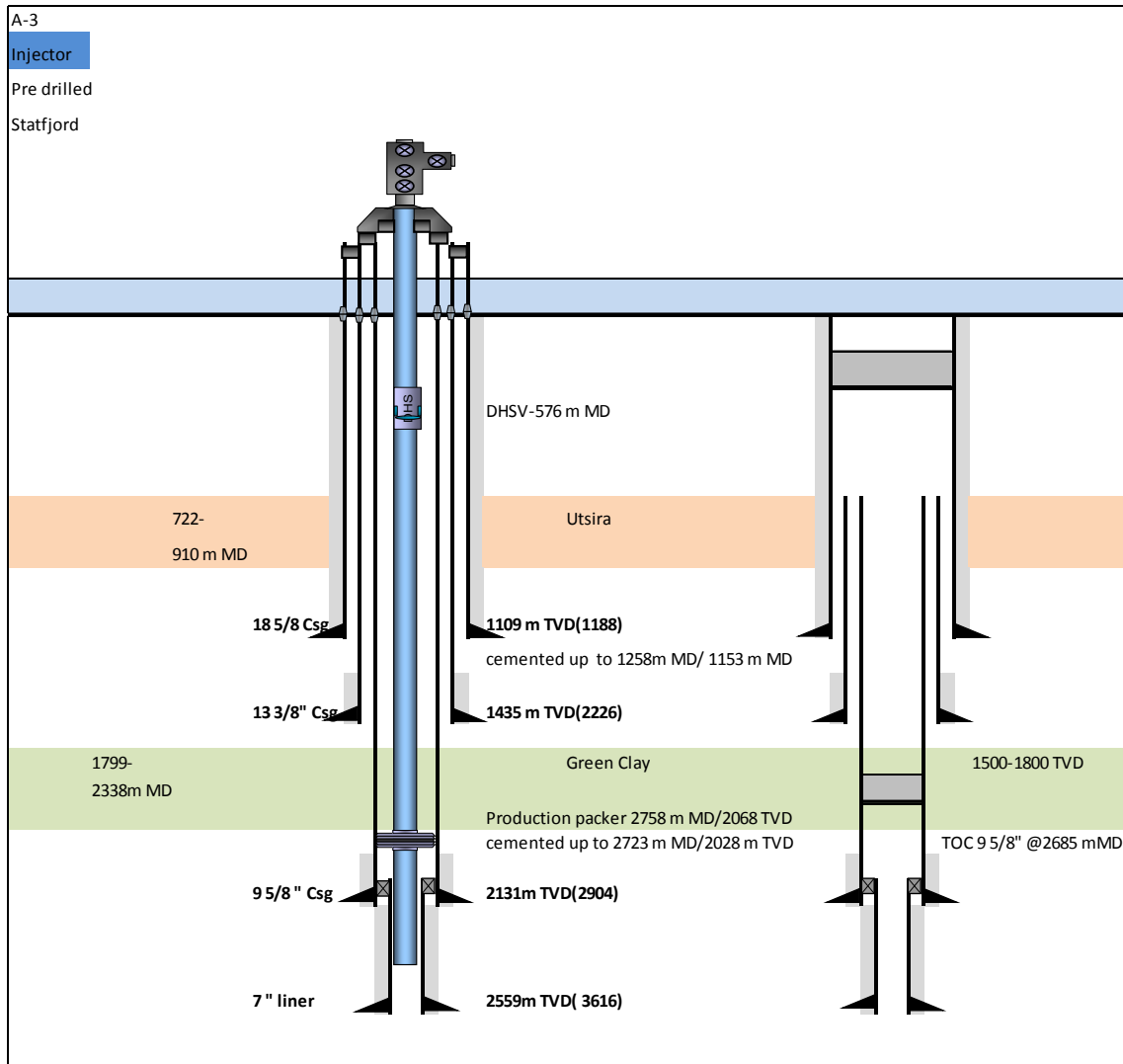


Figure 14: Pre-drilled well A-5 Injector

Reference: 5.1.1.

This is a water injector which does not have an ASV. Since there is no ASV this well will have one less operation step, before removing the upper completion (tubing).

5.2 Production liner with tie-back casing

Many of the wells at Brage has been reentered to change the well path, and target different parts of the reservoir or a nearby reservoir in order to increase production. Most of them are production wells with gas lift. Wells with gas lift has an ASV which requires additional work, before pulling the upper completion.

Pulling the tie-back casing is easier then removing the old 9 5/8" casings. Behind the 9 5/8" casings there can be dirt which makes it hard and time consuming to remove the casing. Behind the tie-back casing it is brine, as a result of that it will be easier to recover. The tie-back will be pulled from approximately 2500 m MD depth.

21 of the wells at Brage has this casing design, and can be P&A in the same way. There are off course some differences when it comes to the completion, they either have sandscreen or perforated liner.

The injection well A-22 has no ASV and the tubing removal will go faster than for the other wells with a production liner.

5.2.1 Permanent Plug & abandonment proposal for wells with production liner and tie-back

This chapter presents a suggested method for permanently plug & abandoned wells with a production liner:

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3.
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor (If ASV is part of the completion)
- Pull upper completion. From DHSV to cut (+/-2500 m MD)
- Set shallow 10 3/4" barrier plug below seabed
- Retrieve tubing hanger
- Retrieve shallow 10 3/4" barrier plug
- Cut and pull tie-back casing below Green clay.
- Log 13 3/8" casing
- Set mechanical plug and pressure test the plug
- Set dual cement plug, primary and secondary barrier
- Tag cement
- Cut and retrieve 13 3/8" shallow
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

5.2.2 Sketches for wells with production liner and tie-back casing.

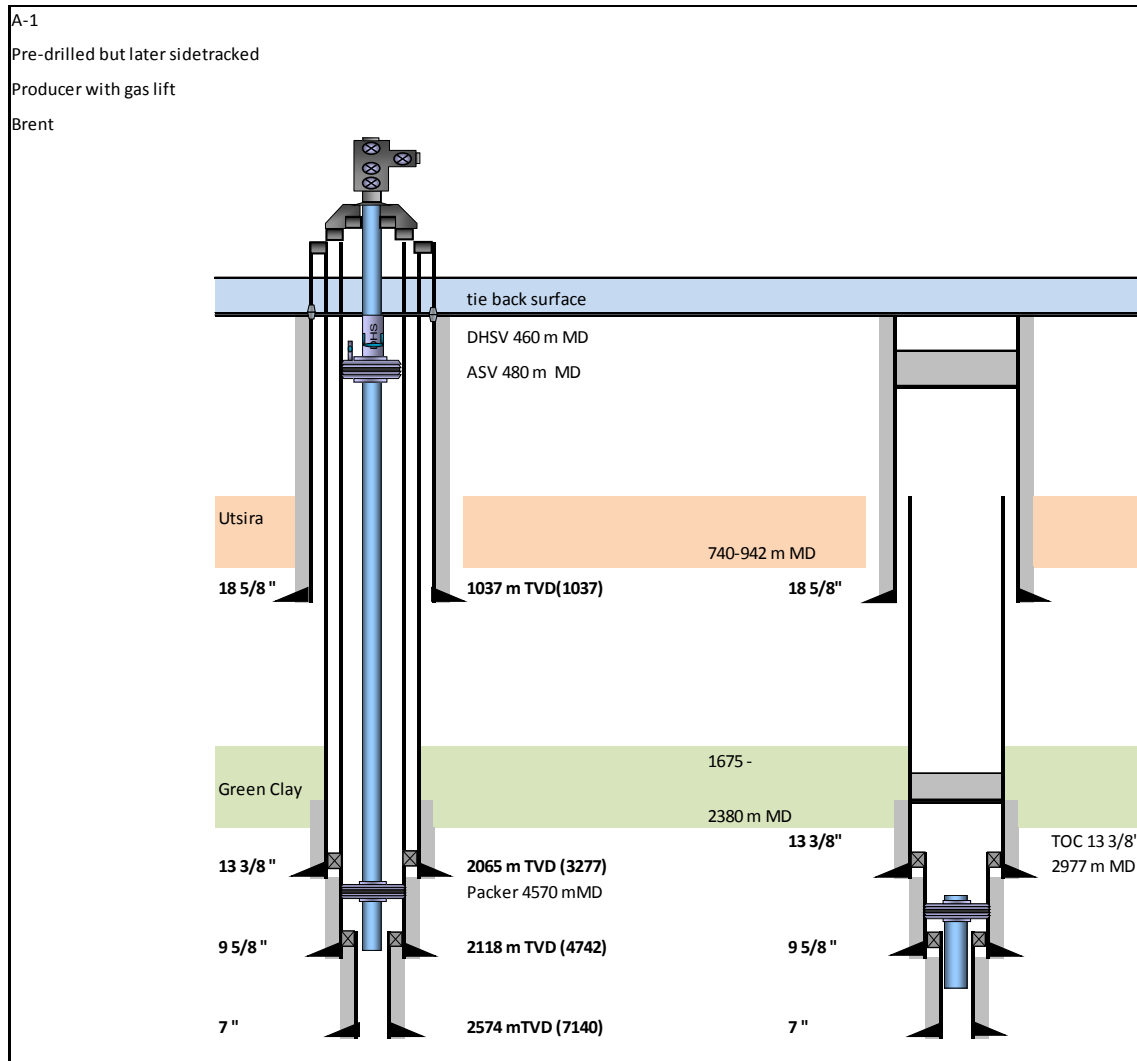


Figure 15:A-1: Pre-drilled but later sidetracked

Well A-1 was originally pre-drilled but was sidetracked in 2008. Since it now longer has an internal conductor it is categorized as a well with a production liner with tie-back casing.

Operational sequence. Ref.: 5.2.1.

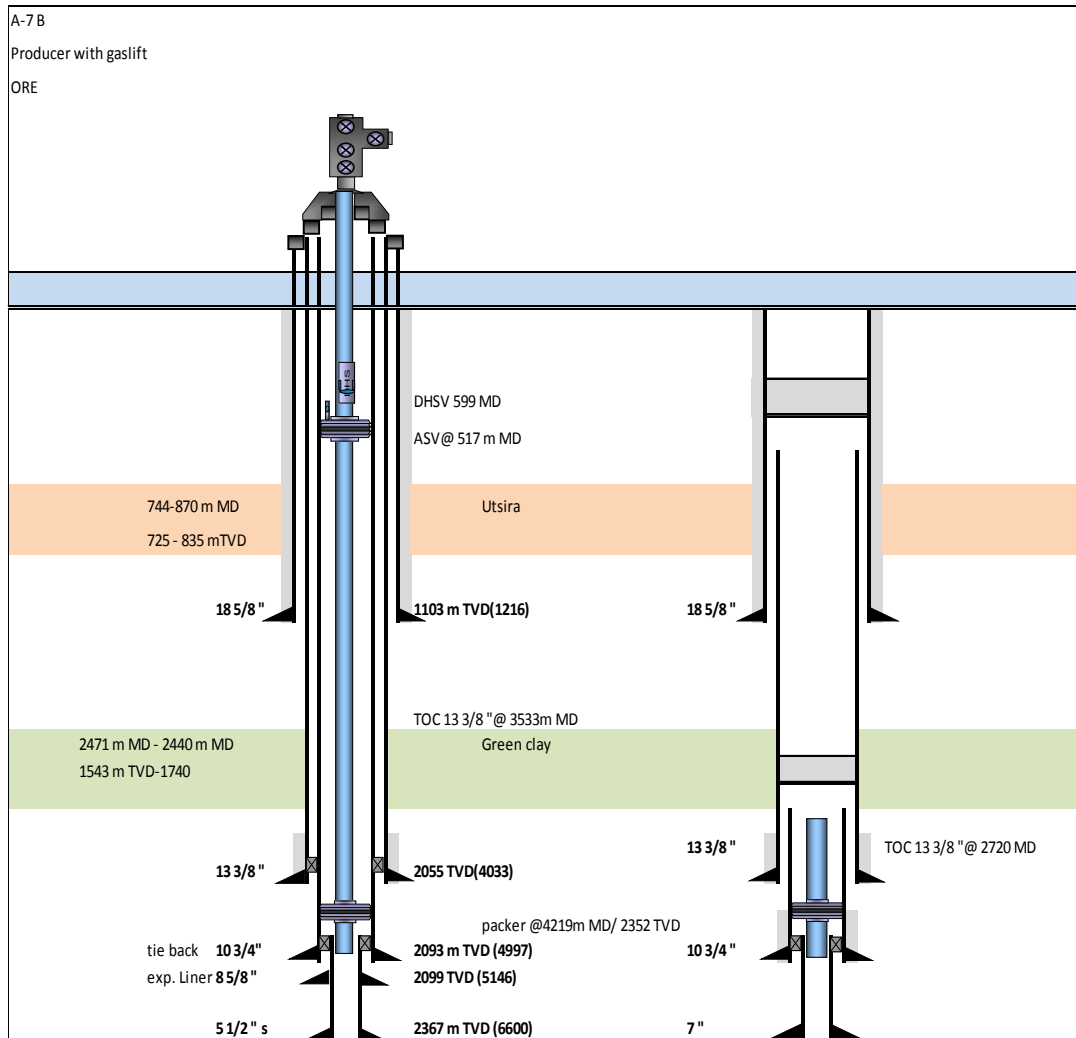


Figure 16: Well A-7: producer with gas lift

Reference: 5.2.1

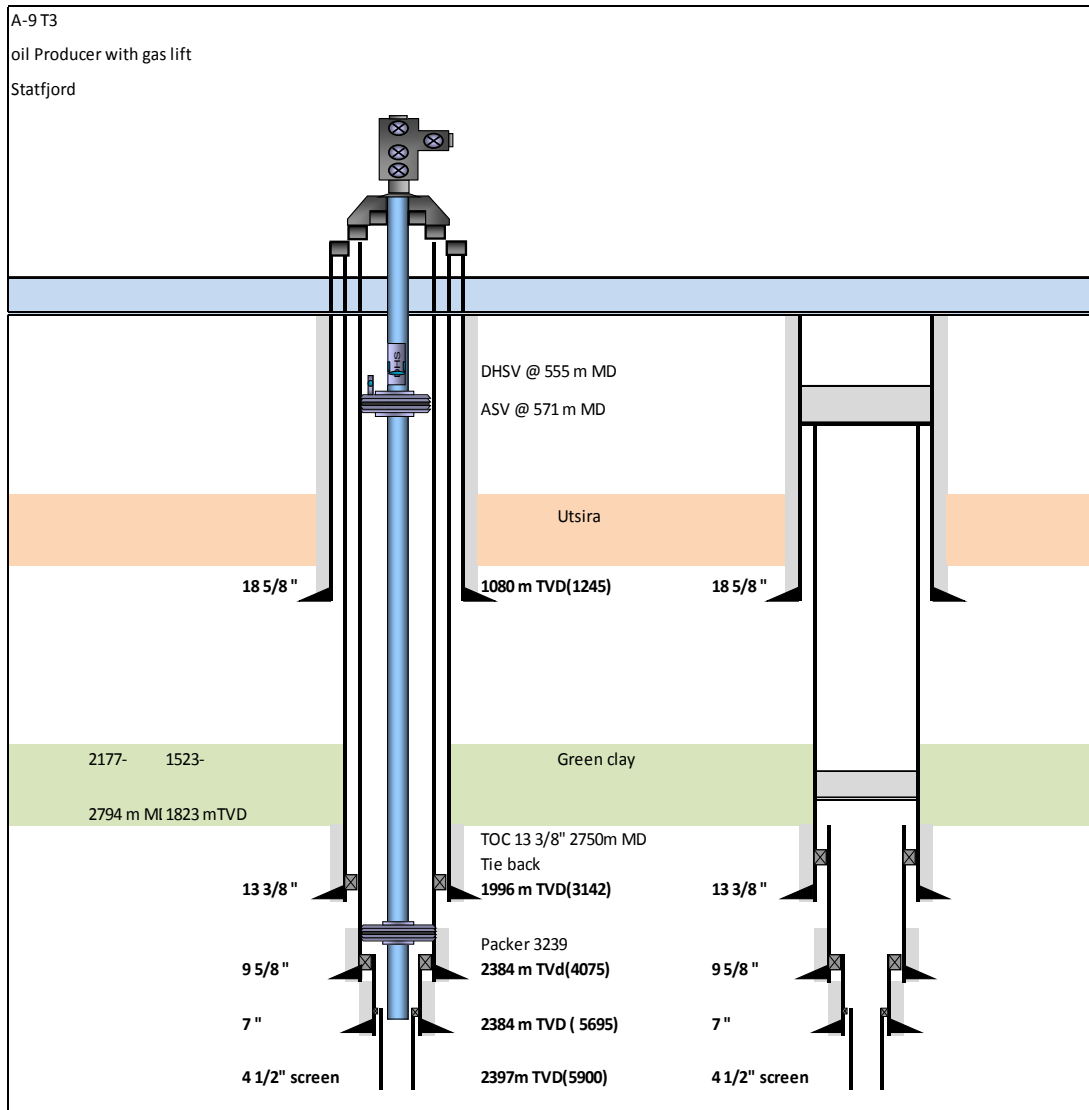


Figure 17: Well A-9: Producer with gas lift

Reference: 5.2.1

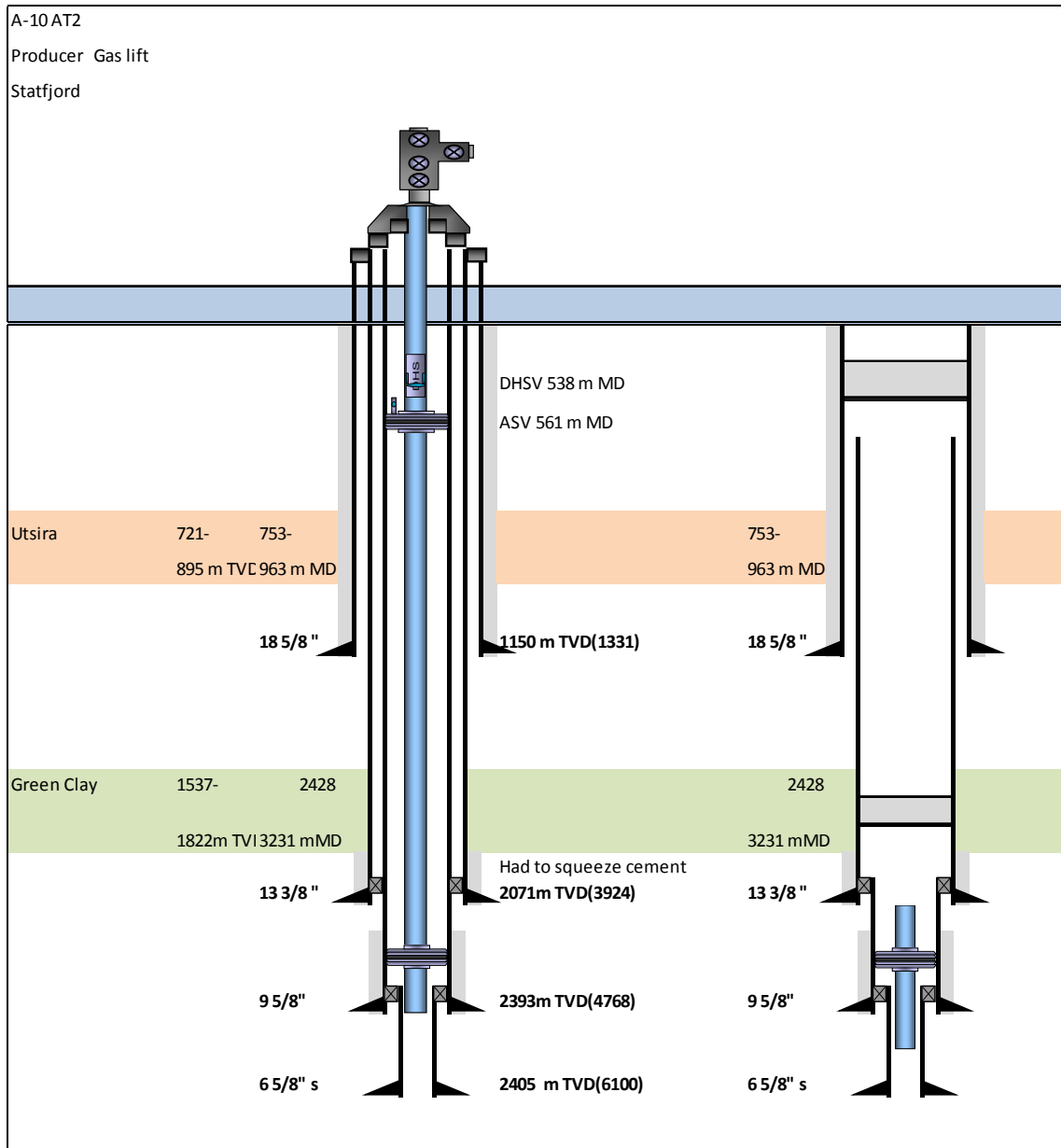


Figure 18: Well A-10: Producer with gas lift

Reference: 5.2.1

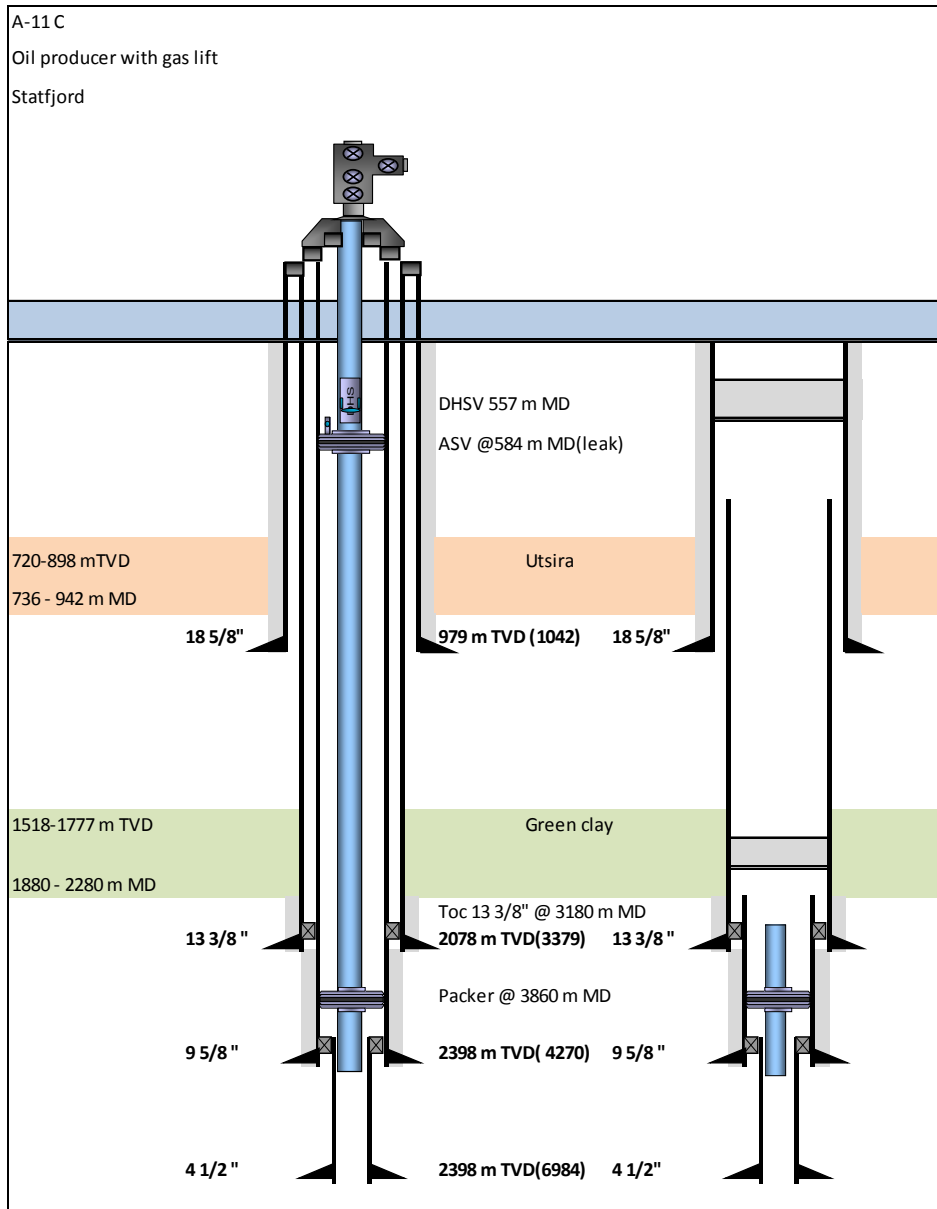


Figure 19: Well A-11: Oil producer with gas lift

Reference: 5.2.1

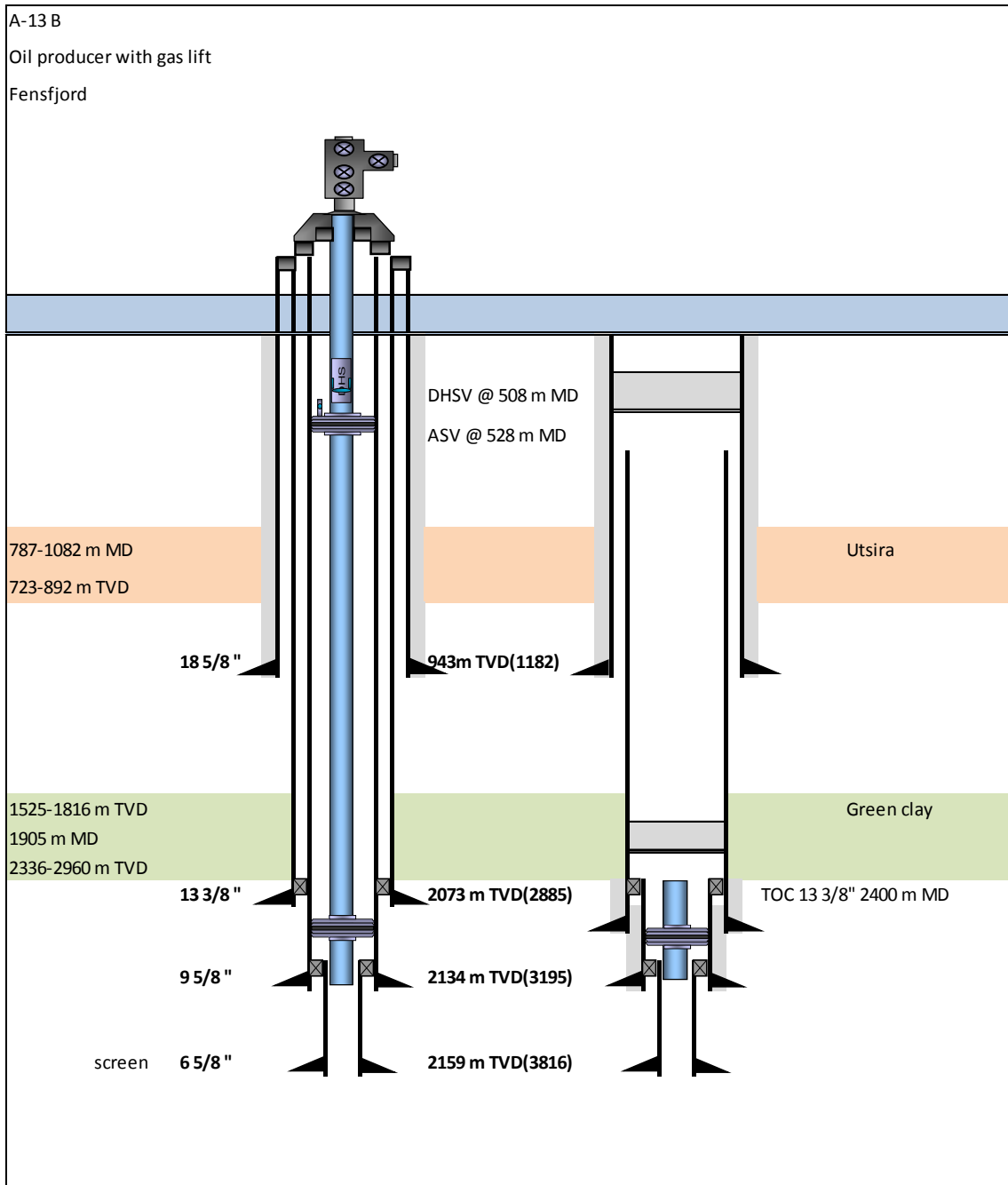


Figure 20: Well A-13: Producer with gas lift

Reference: 5.2.1

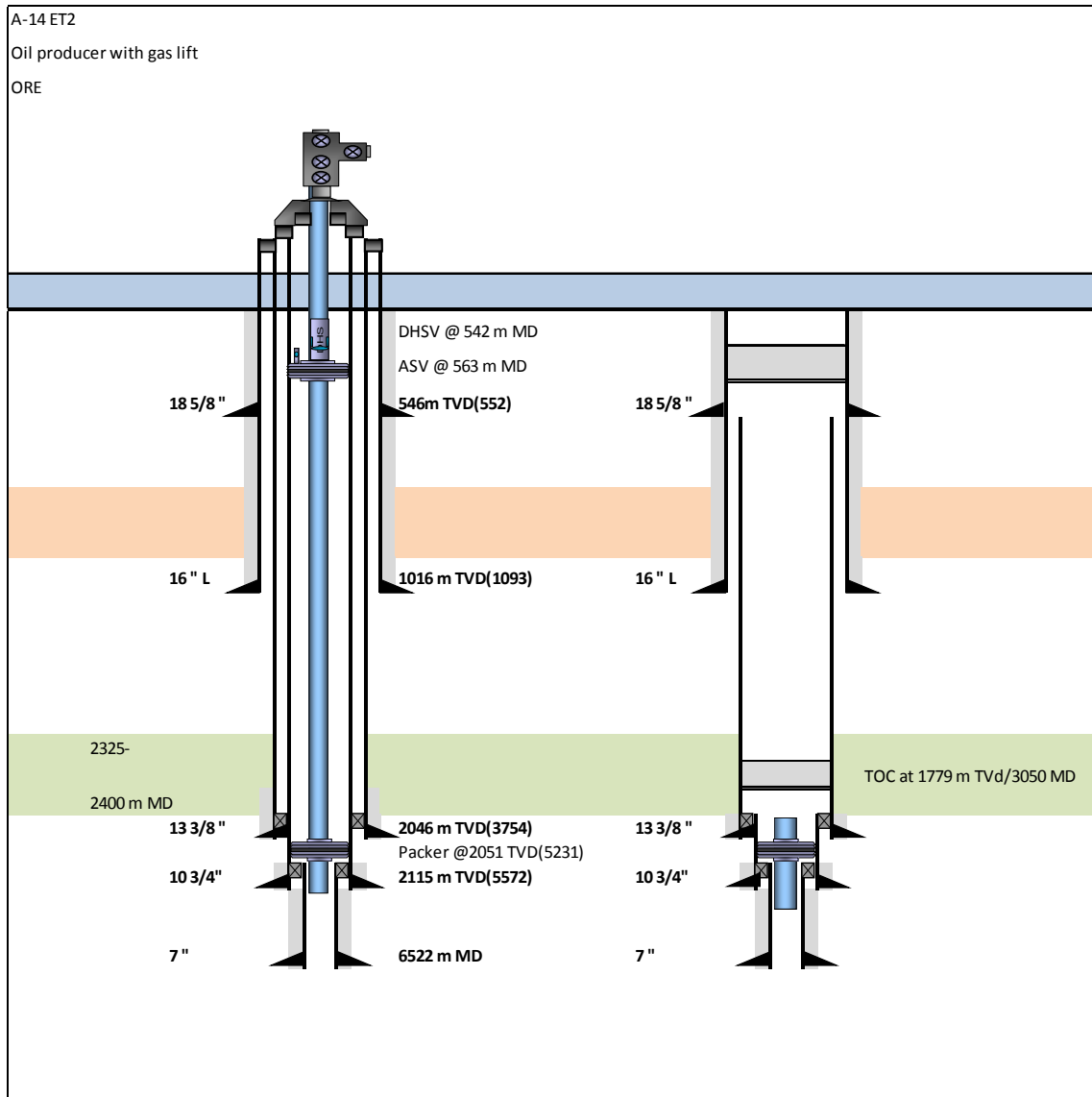


Figure 21: Well A-14: Producer with gas lift

Reference: 5.2.1

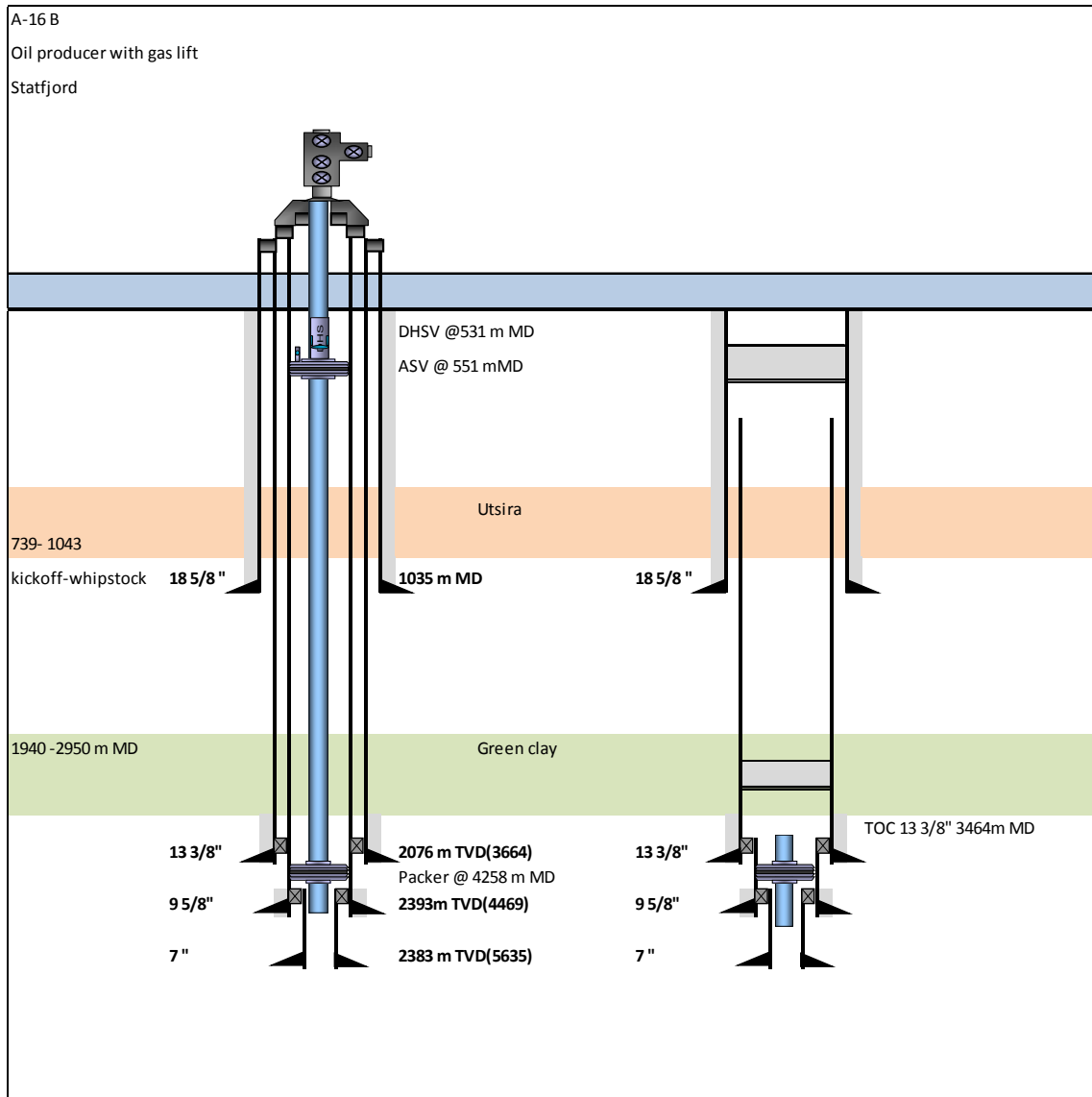


Figure 22: Well A-16: Producer with gas lift

Reference: 5.2.1

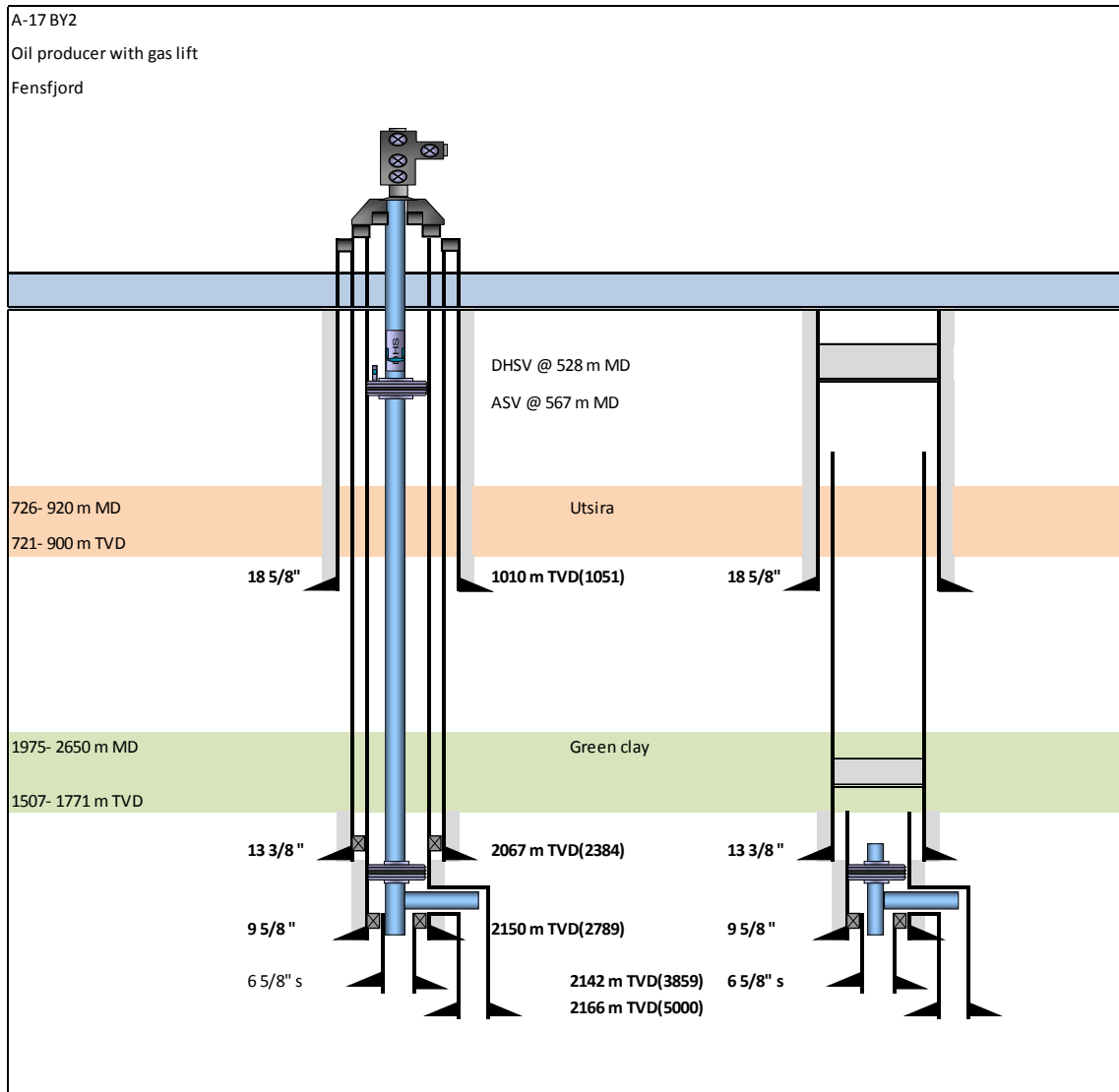


Figure 23: Well A-17: Producer with gas lift

Reference: 5.2.1.

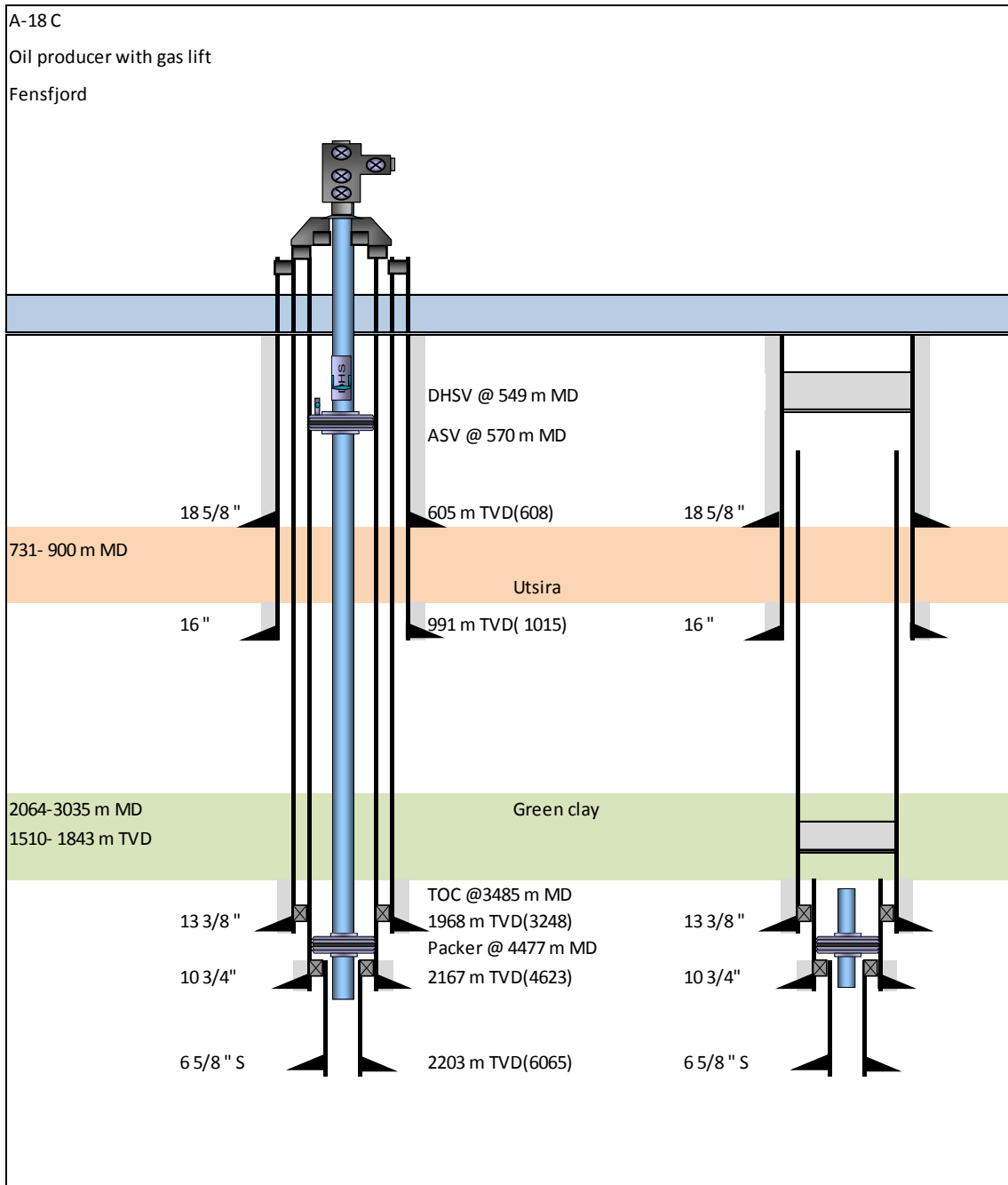


Figure 24: Well A-18: Producer with gas lift

Reference: 5.2.1

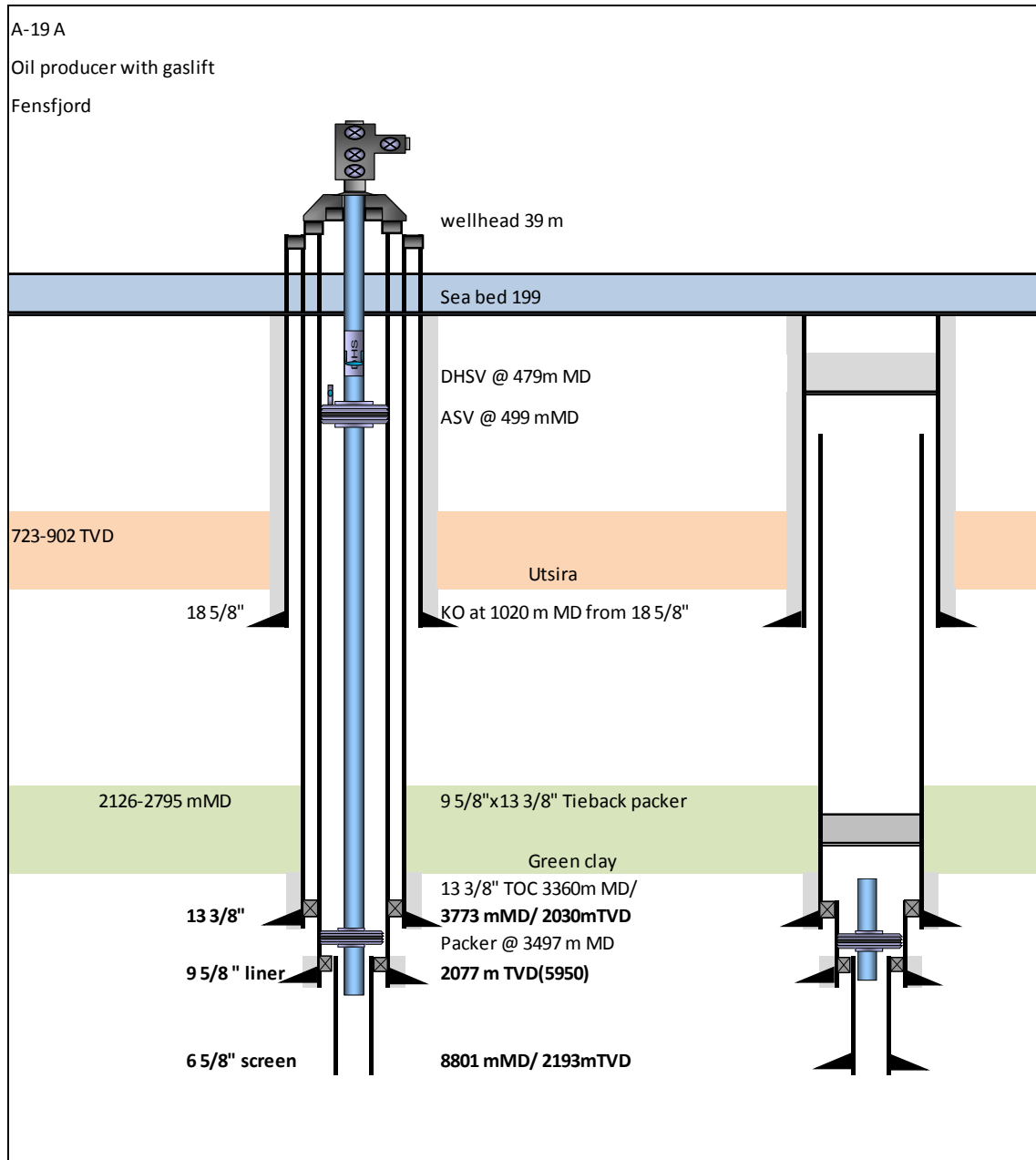


Figure 25: Well A-19: Producer with gas lift

Reference: 5.2.1

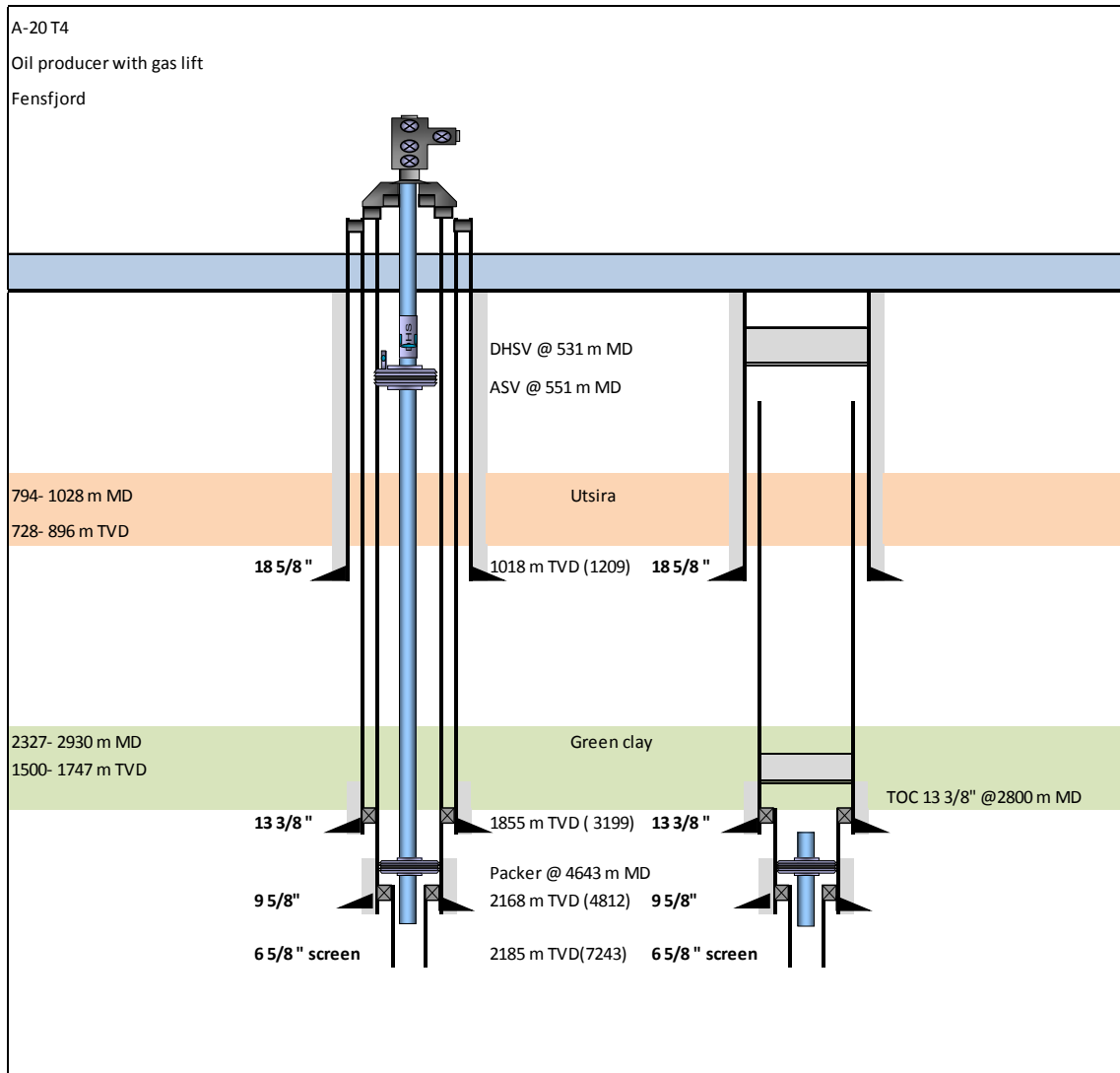


Figure 26: Well A-20: Producer with gas lift

Reference: 5.2.1

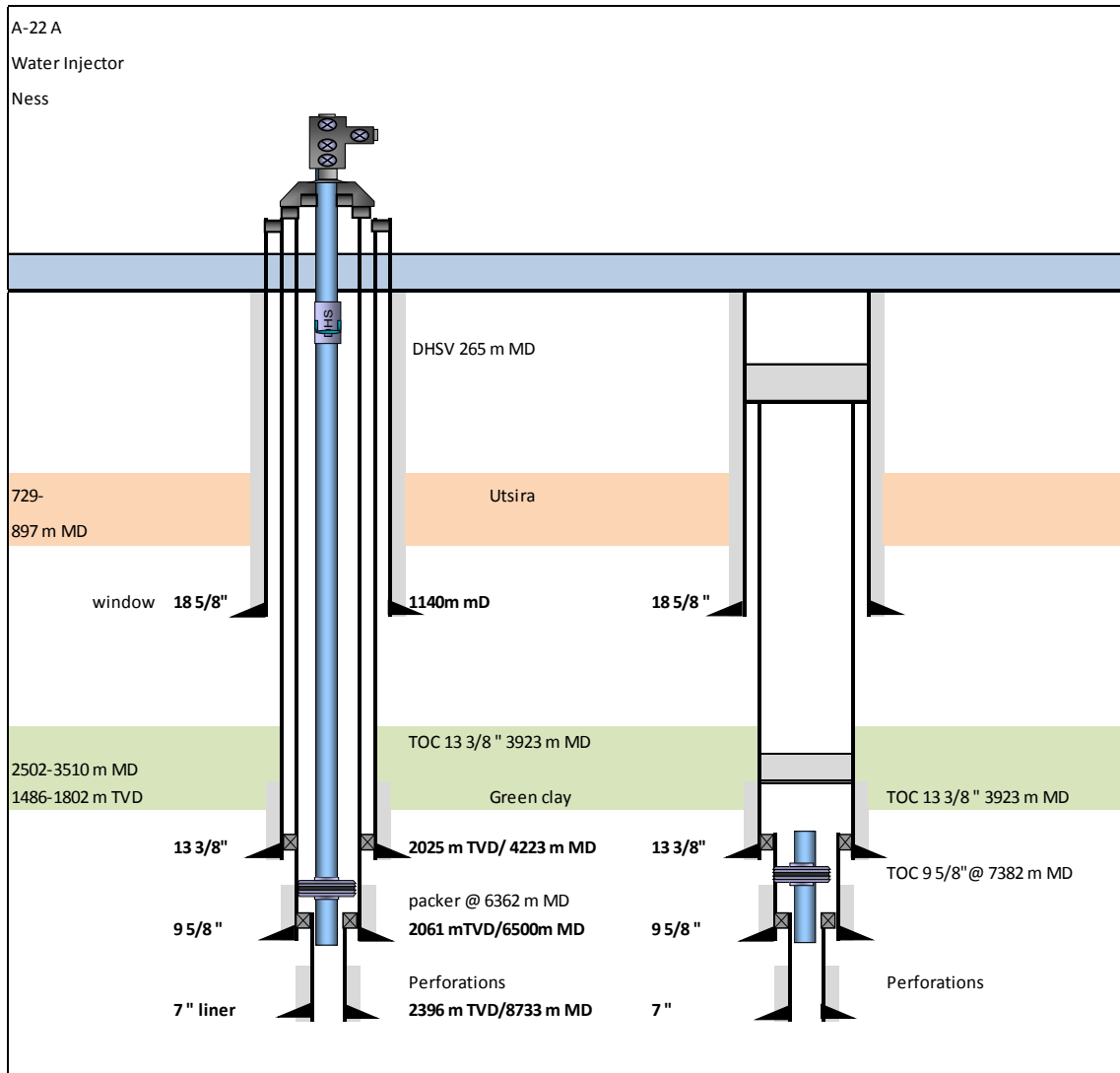


Figure 27: Well A-22: Water injector

As shown in Figure 27 above this well does not have an ASV which will decrease the time for pulling the tubing. Reference: 5.2.1

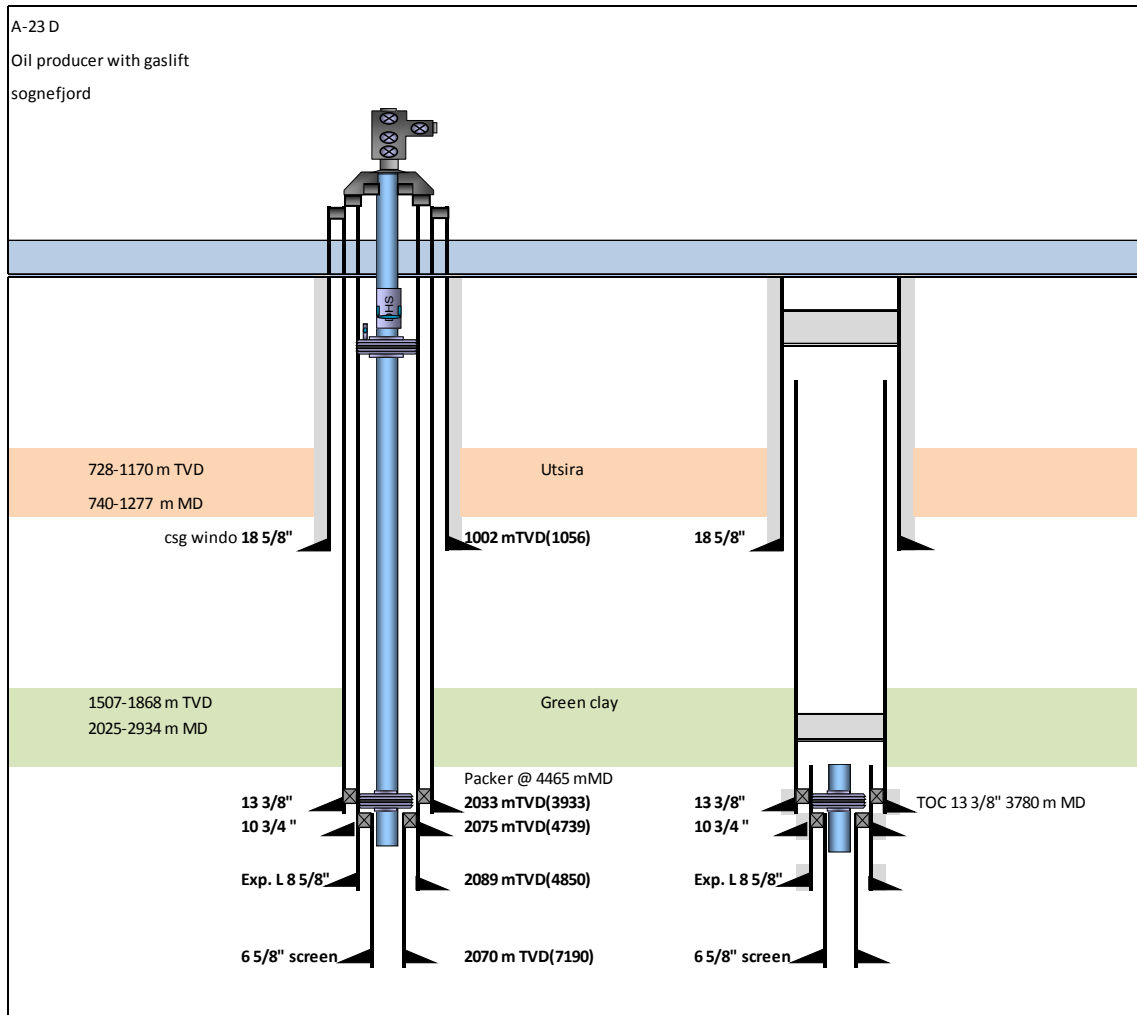


Figure 28: Well A-23: Producer with gas lift

Reference: 5.2.1

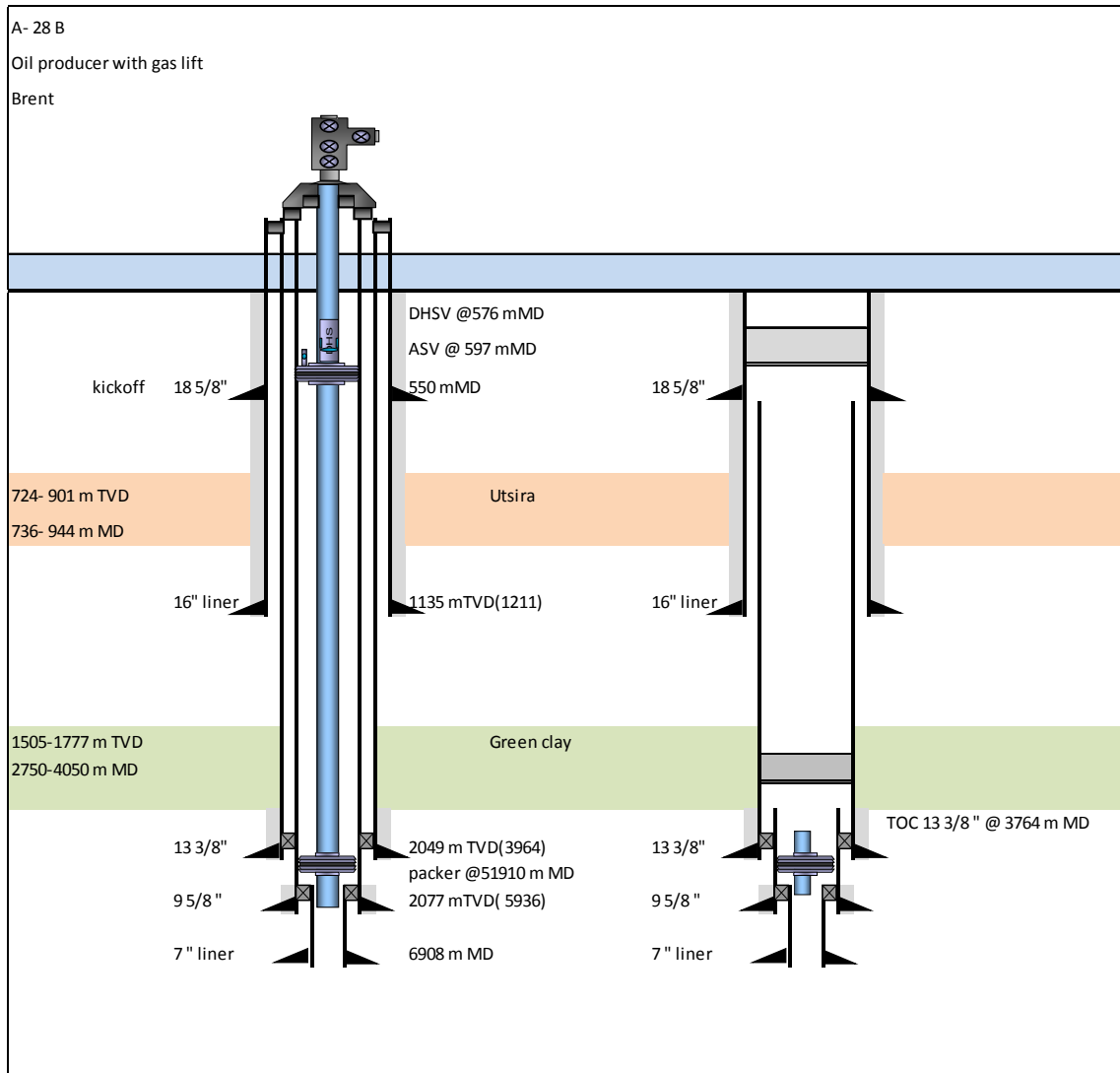


Figure 29: Well A-28: Producer with gas lift

Reference: 5.2.1

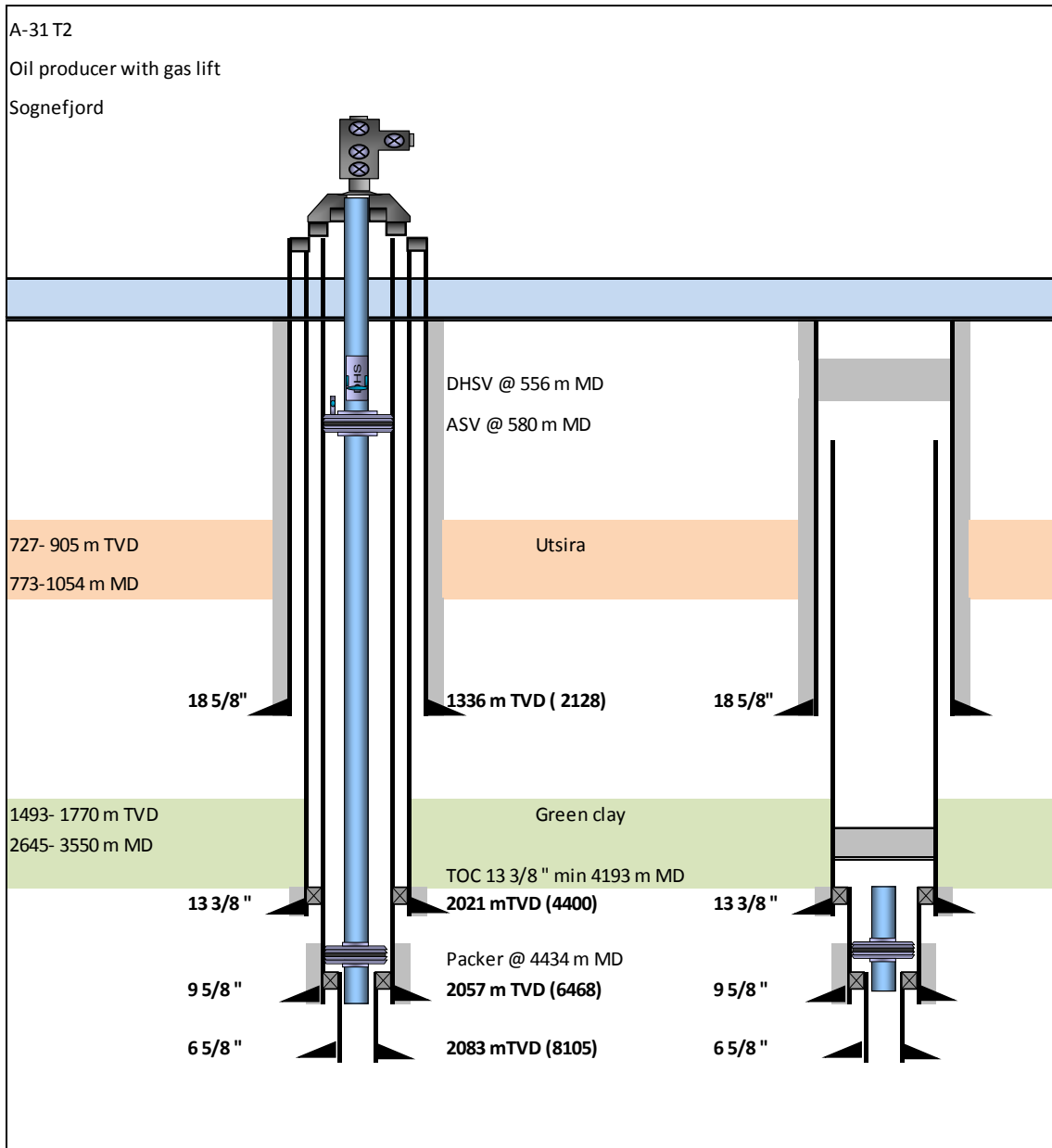


Figure 30: Well A-31: Producer with gas lift

Reference: 5.2.1

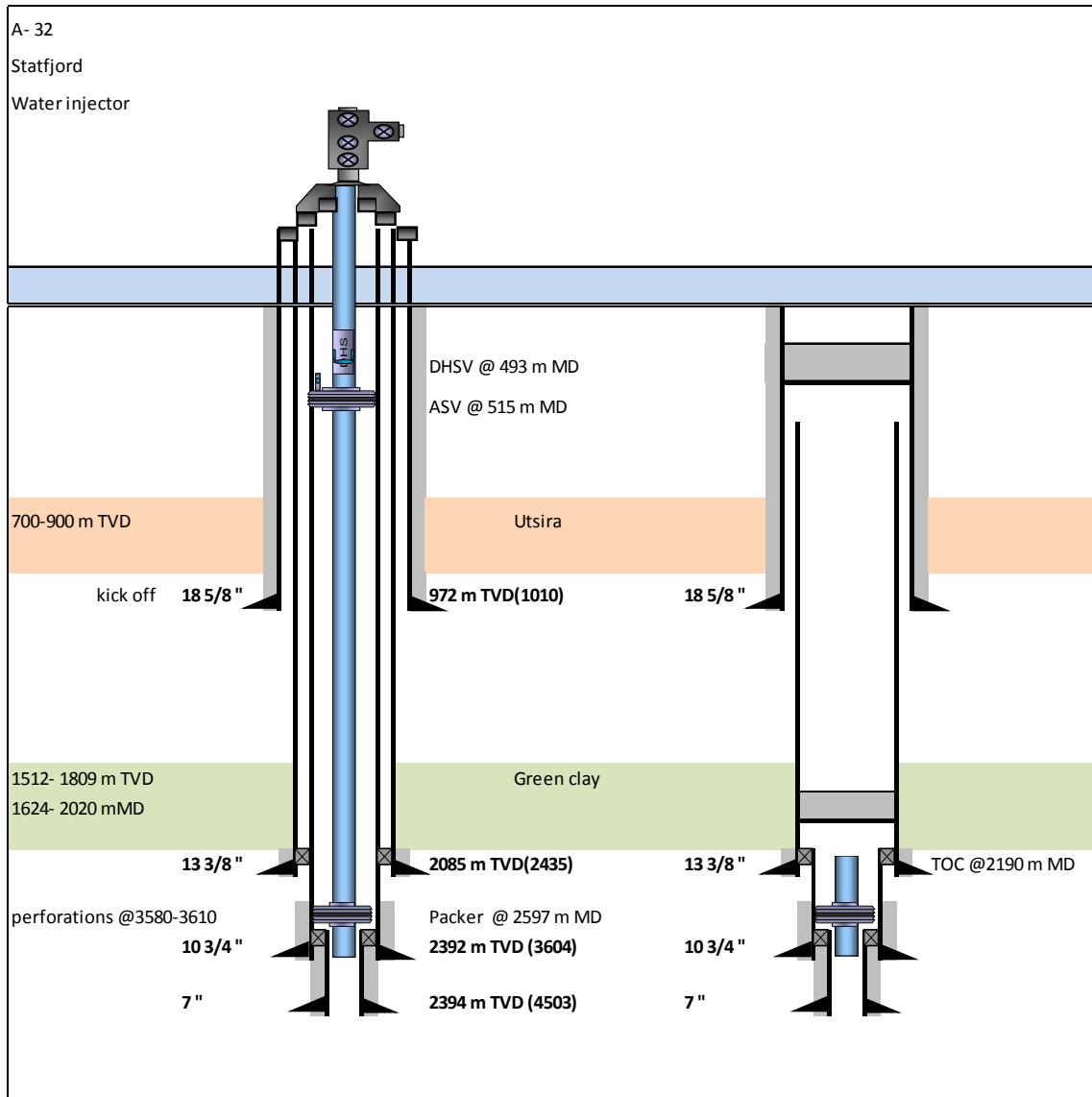


Figure 31: Well A-32: Water injector

Reference: 5.2.1.

Well A-32 was originally an oil producer but is now functioning as a water injector. An ASV is not required for a water injector but this well has one since it was converted from an oil producer.

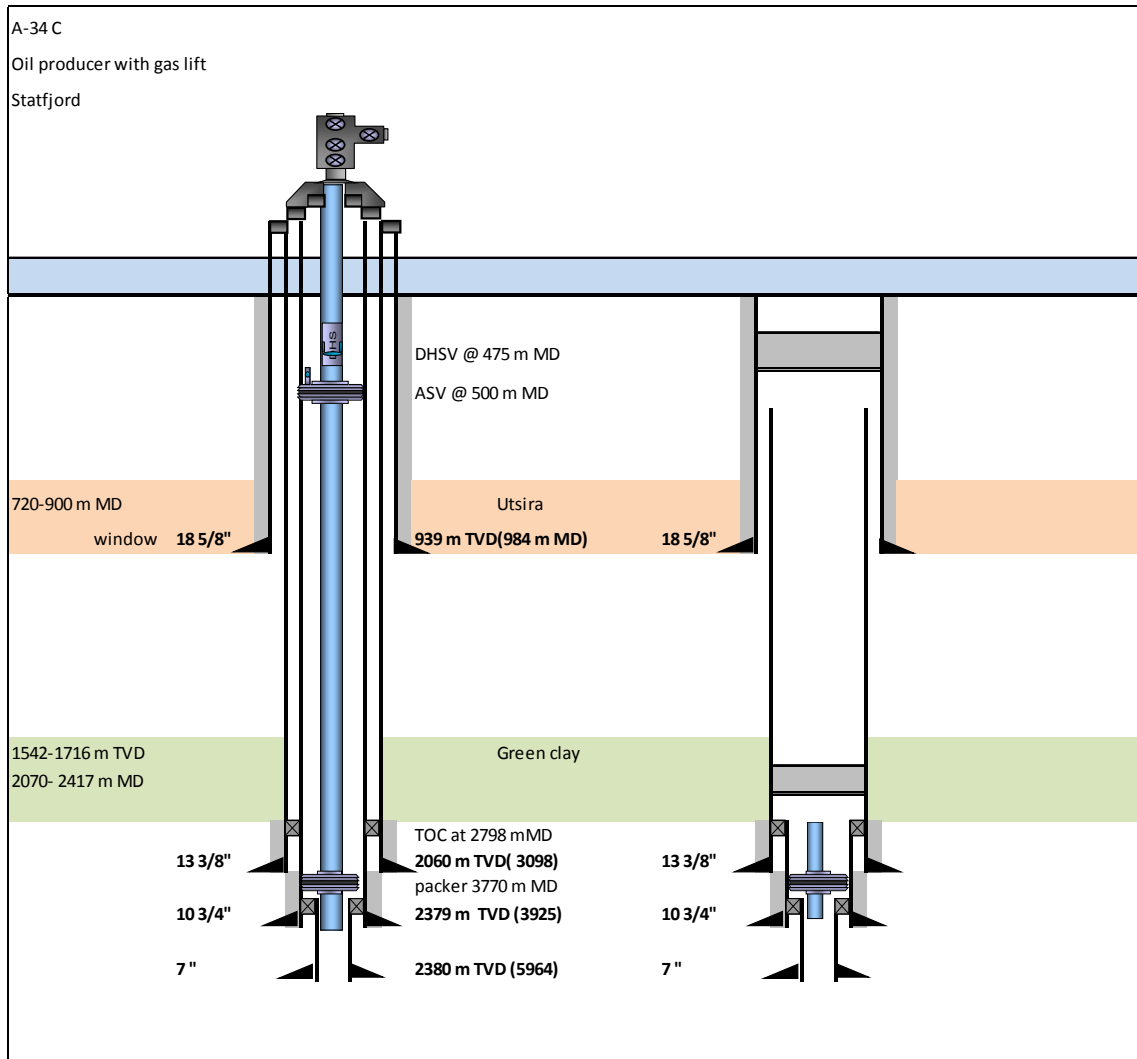


Figure 32: Well A-34: Producer with gas lift

Reference: 5.2.1

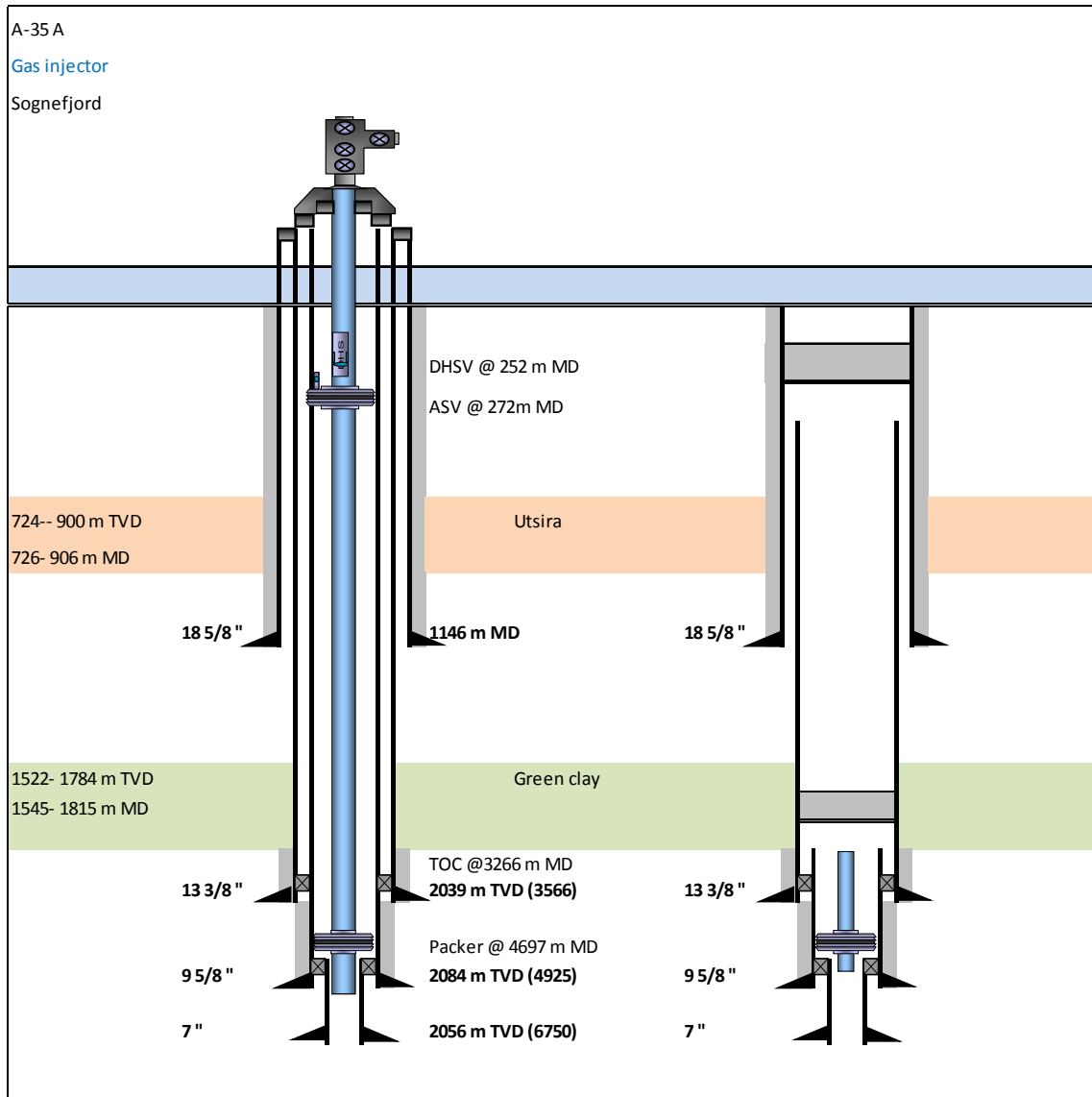


Figure 33: Well A-35: Gas injector

Reference: 5.2.1

Only gas injector at Brage.

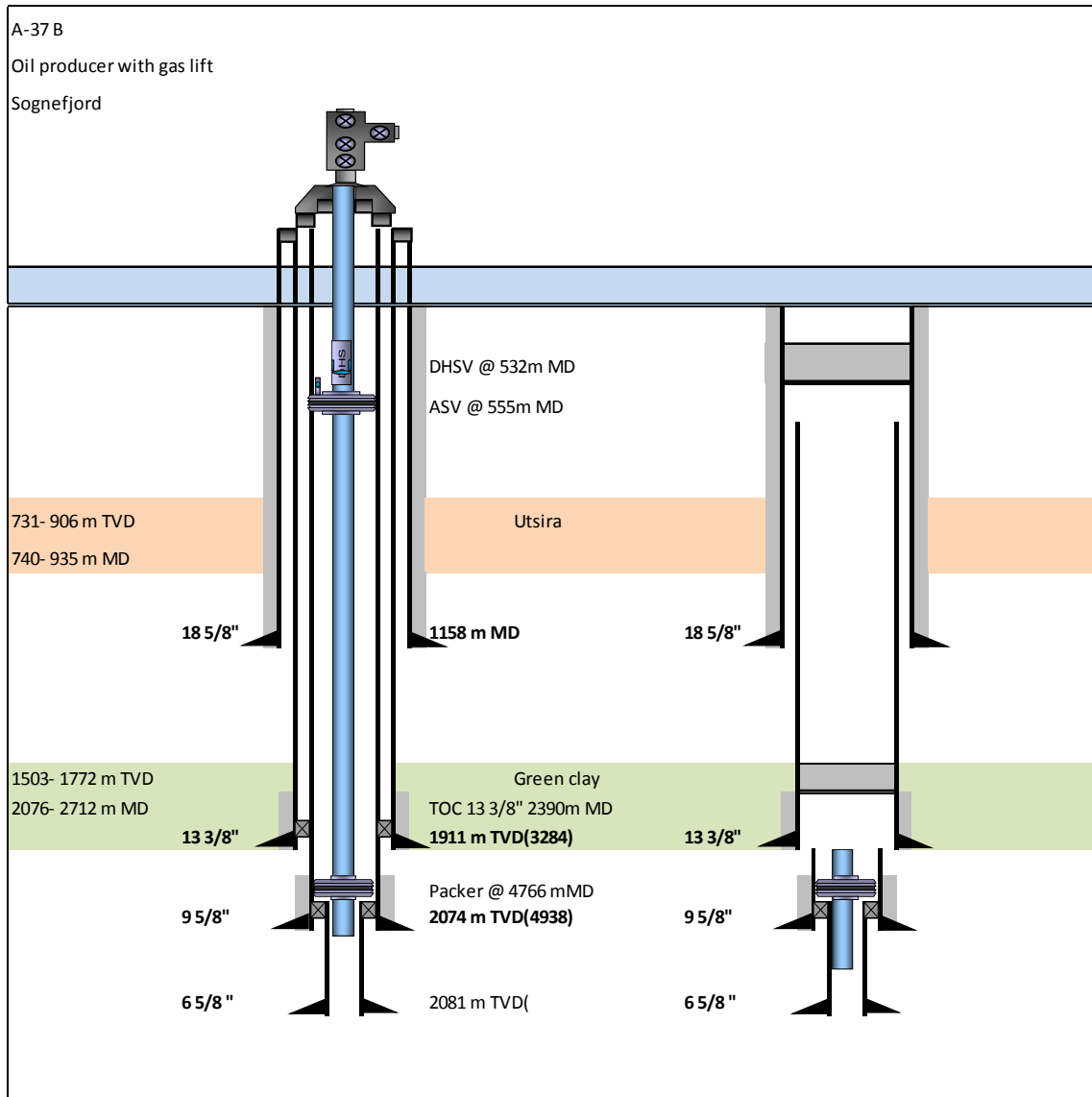


Figure 34: Well A-37: producer with gas lift

Reference: 5.2.1

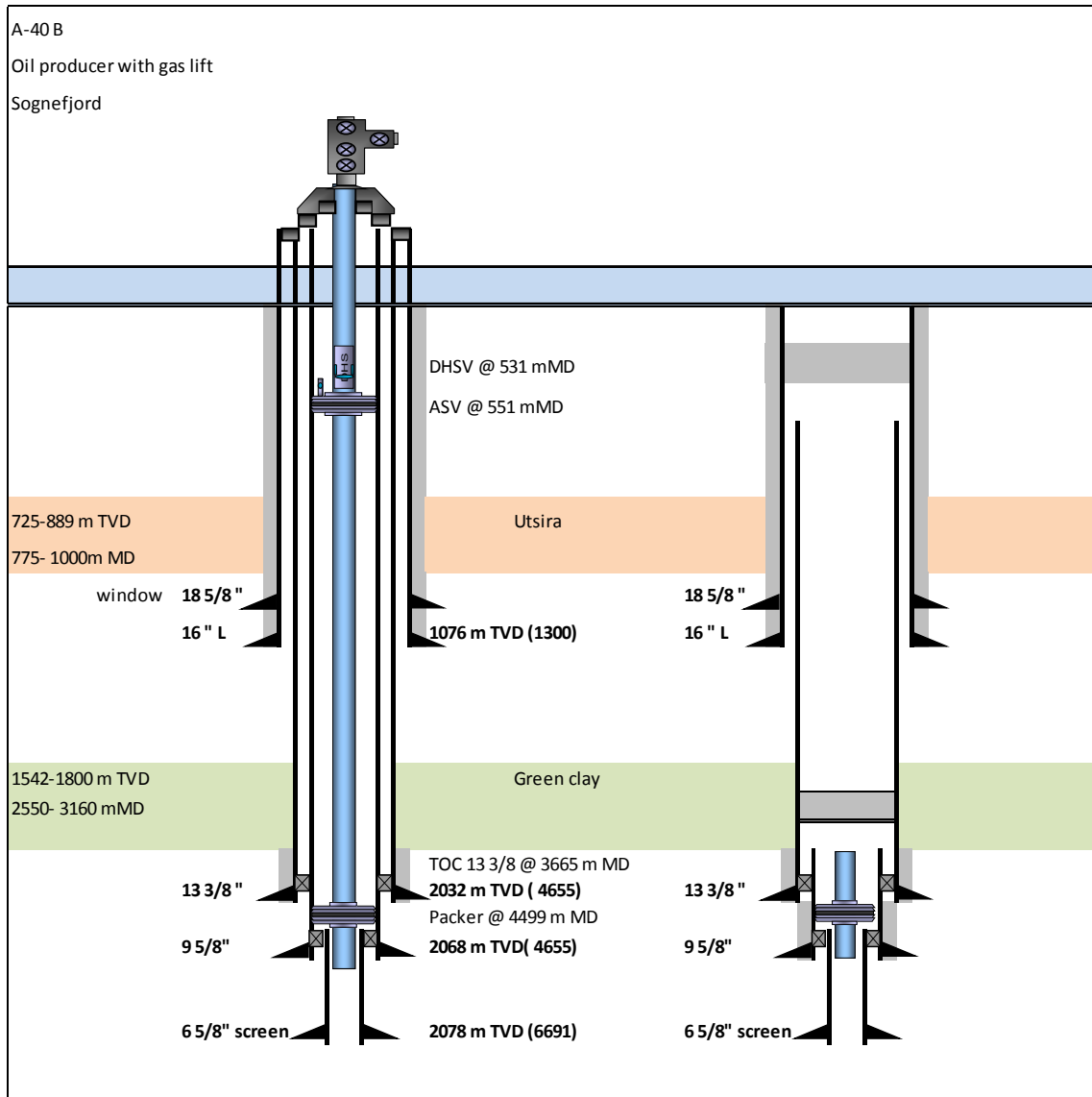


Figure 35: Well A-40: Producer with gas lift

Reference: 5.2.1

5.3 Simplified casing design

Simplified casing design involves wells that has a casing design with a dummy 18 5/8" casing. The 18 5/8" casing does not extend further then 180 m, which means it does not even extend below seabed. In wells like this, the 9 5/8" is in direct contact with the Green clay formation, and no casings has to be retrieved prior to logging and setting the dual barrier plug. The 9 5/8" will be cut shallow and the environmental plug will be set inside the 13 3/8".

In addition, there are two wells with a short 18 5/8" casing, where the 13 3/8" casing also needs to be cut and pulled shallow before setting the environmental plug inside the 18 5/8" casing.

Some of the wells with simplified casing designs are injectors, and do not have an ASV, which will reduce the time for pulling of the upper completion.

5.3.1 Permanent abandonment proposal for simplified casing design

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor (If ASV is part of the completion)
- Pull upper completion. From DHSV to cut (+/-2500 m MD)
- Retrieve tubing hanger
- Log 9 5/8" casing
- Set mechanical plug and pressure test
- Set dual barrier plug
- Tag plug
- Cut & pull 9 5/8" shallow
- Cut & pull 13 3/8" shallow (This operation step is only done for wells with a short 18 5/8")
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

All the wells below will be abandoned in the following way as listed above. There are some differences depending if they got an ASV or not. There are also two wells with a short 18 5/8" instead of a "dummy" casing.

5.3.2 Sketches for wells with simplified casing design

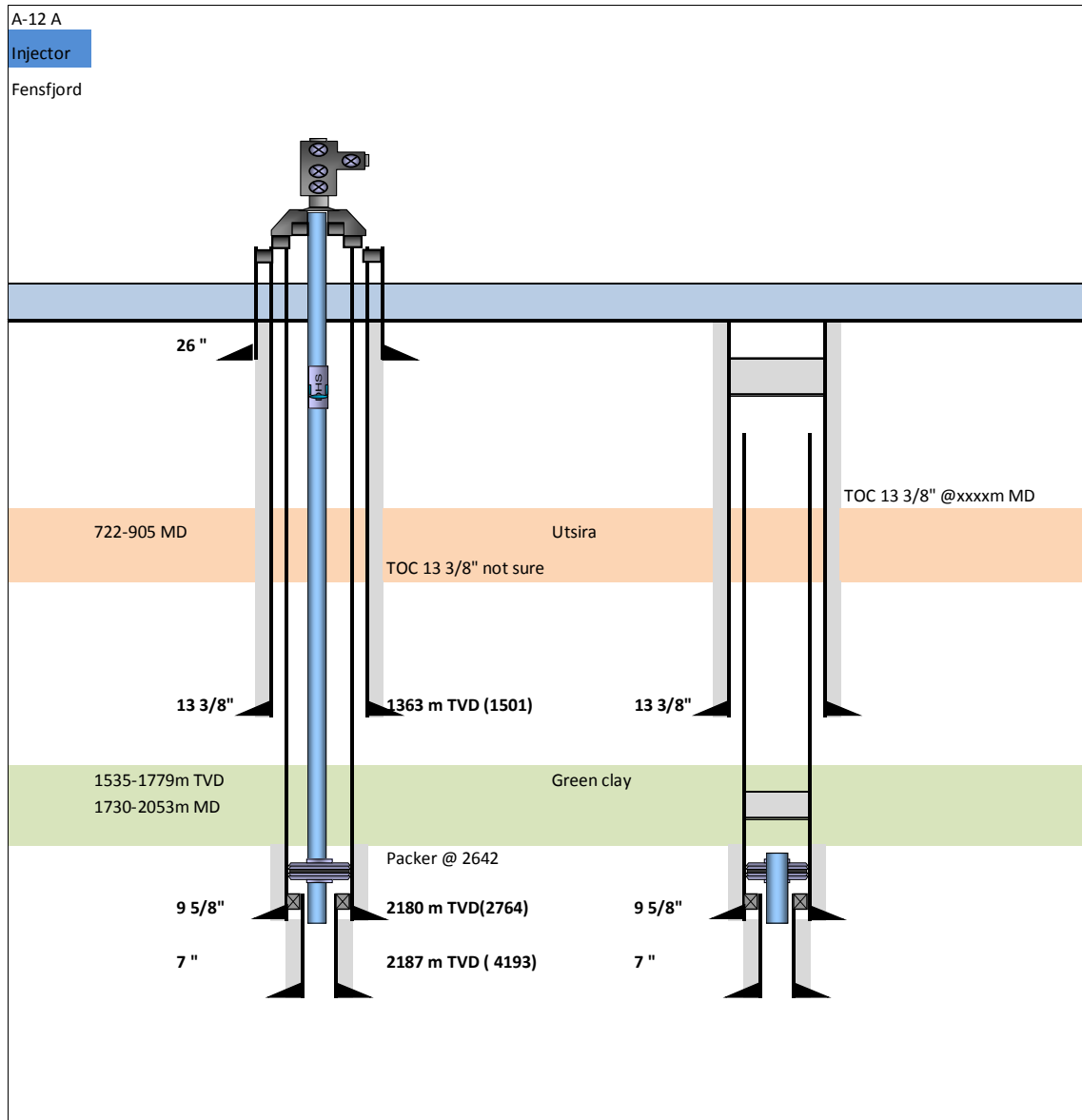


Figure 36: Well A-12: Water injector

Reference: 5.3.1.

Well A-12 is a water injector. Does not have an ASV.

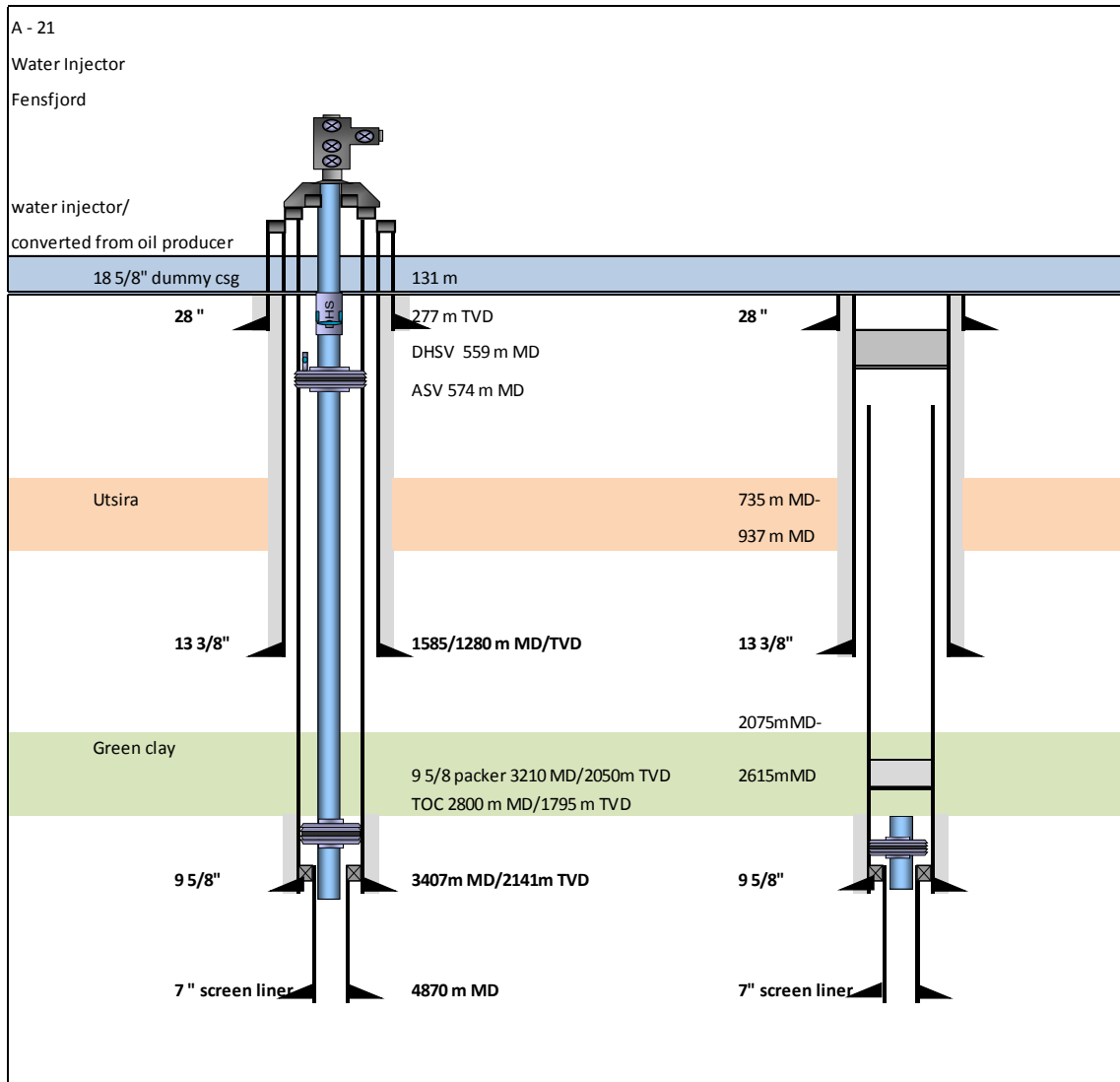


Figure 37: Well A-21: water injector

Reference: 5.3.1.

Well A-21 was originally an oil producer with gas lift, but since then it has been changed to a water injector. Still require removal of ASV, since the wells has not been recompleted.

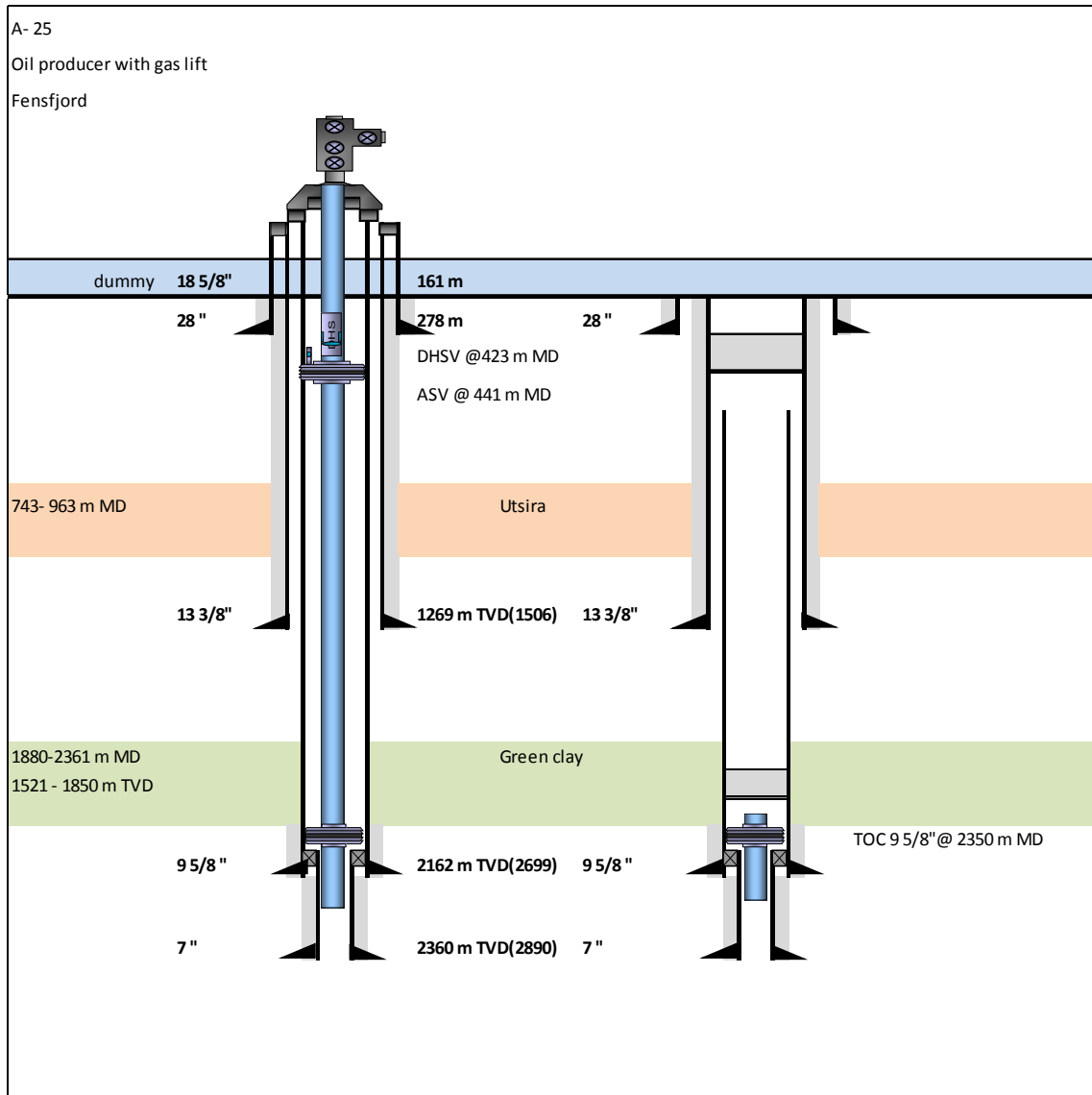


Figure 38: Well A-25: Oil producer with gas lift

Reference: 5.3.1.

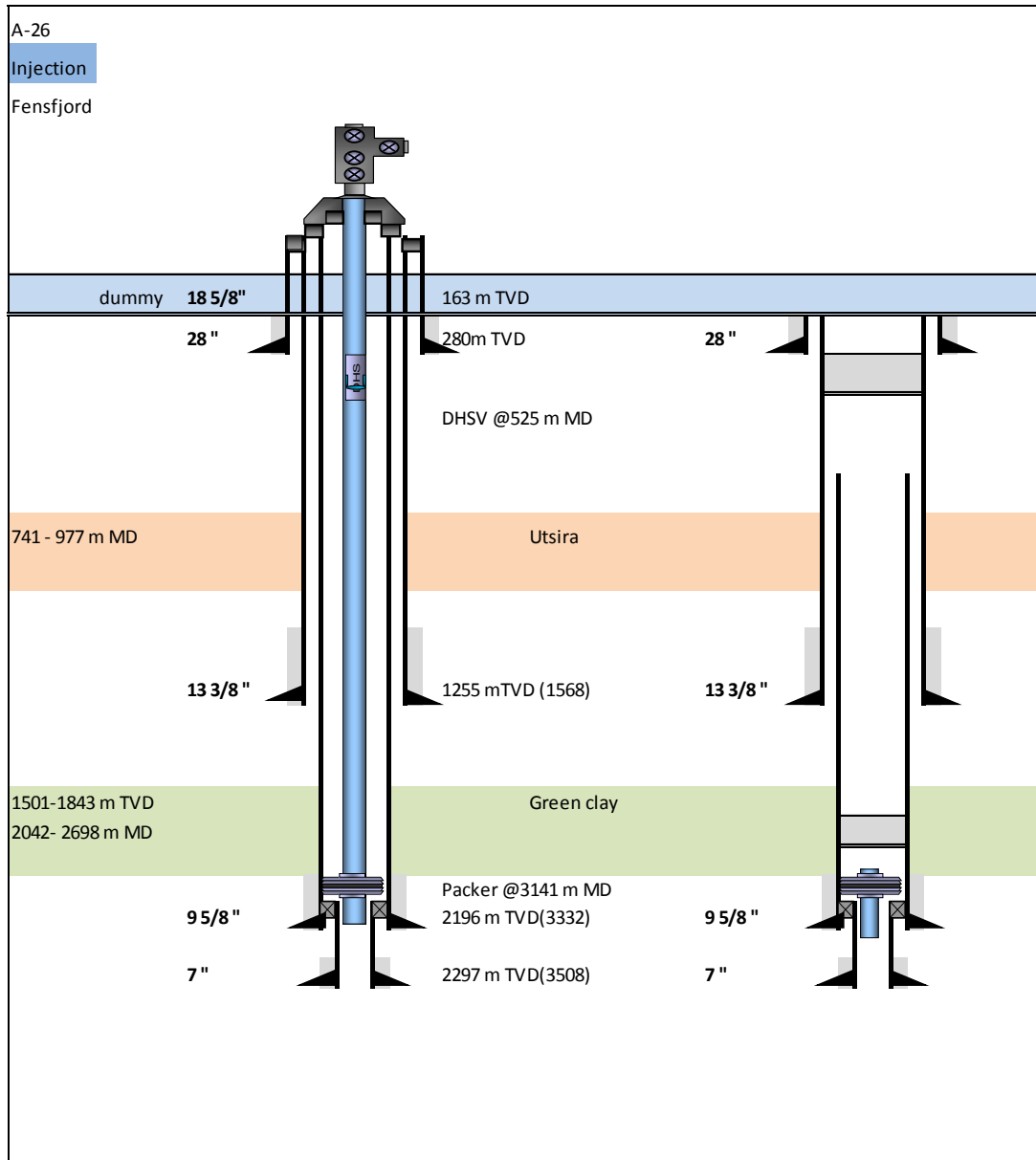


Figure 39: Well A-26: Water injector

Reference: 5.3.1.

Well A-26 does not have an ASV.

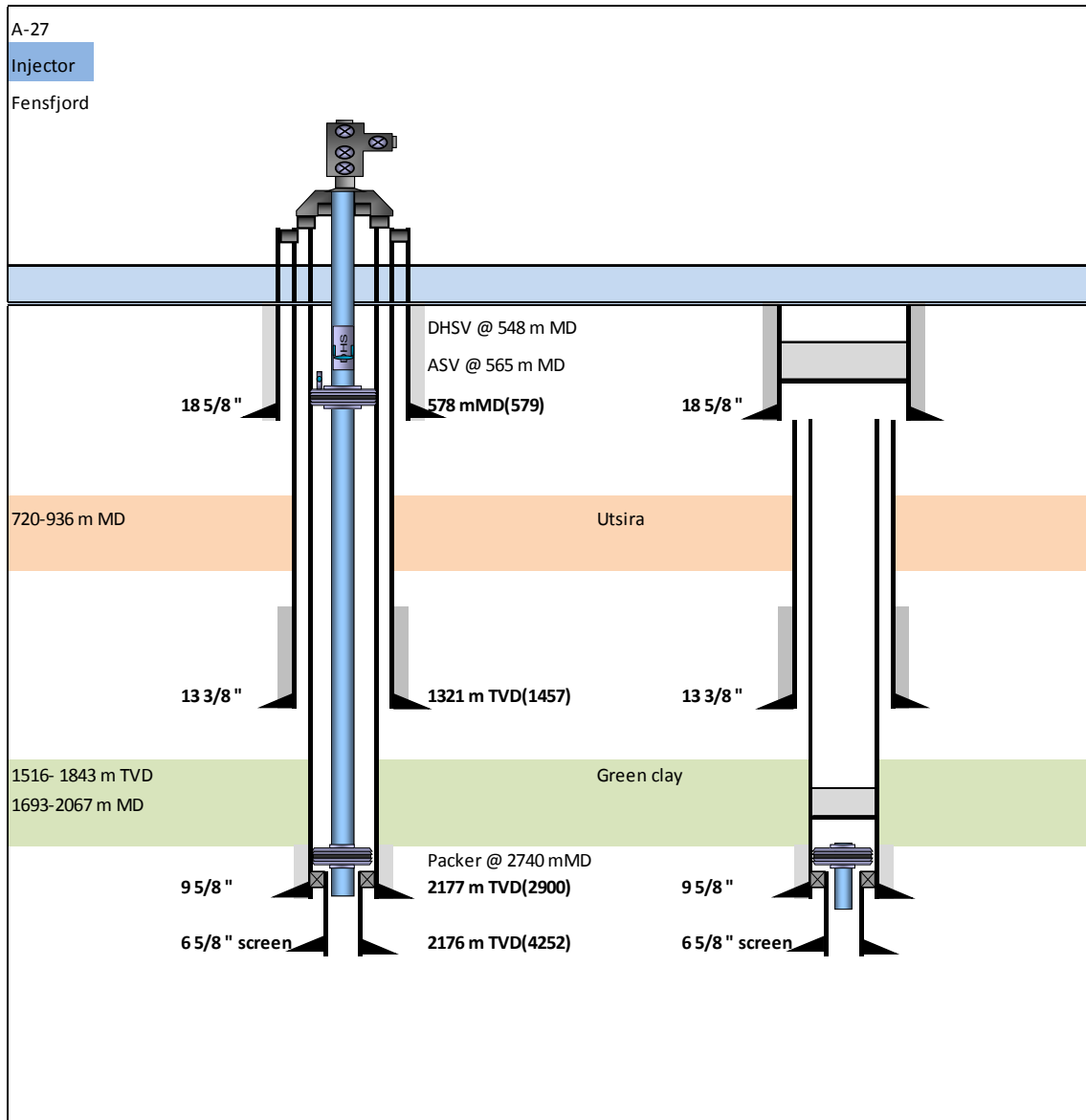


Figure 40: Well A-27: Water injector

Reference: 5.3.1.

Well A-27 was originally an oil producer with gas lift, but since then it has been changed to a water injector. This wells also got a shallow 18 5/8" instead of a dummy casing. The 18 5/8" casing needs to be cut prior to setting the environmental plug.

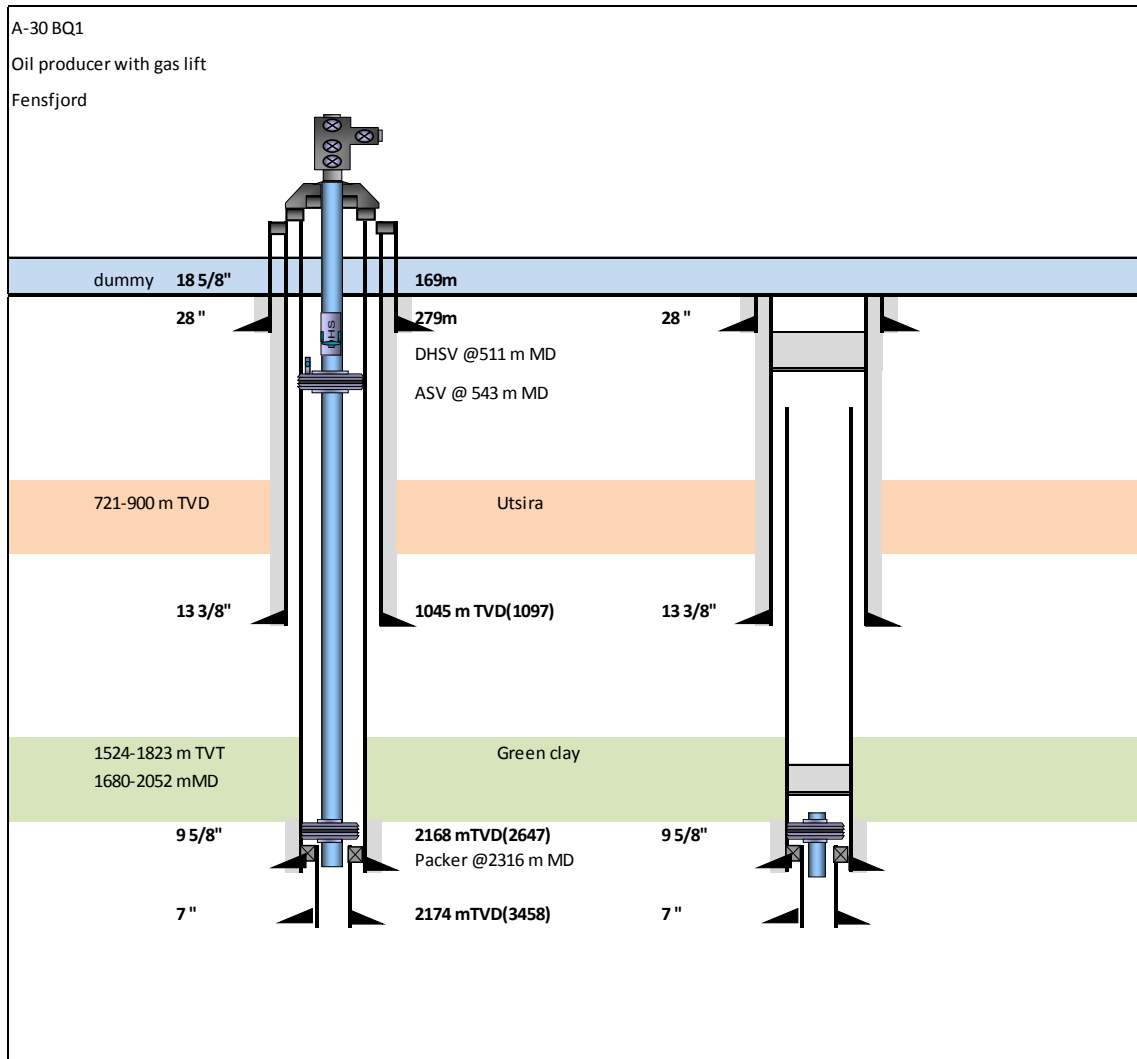


Figure 41: Well A-30: Producer with gas lift

Reference: 5.3.1.

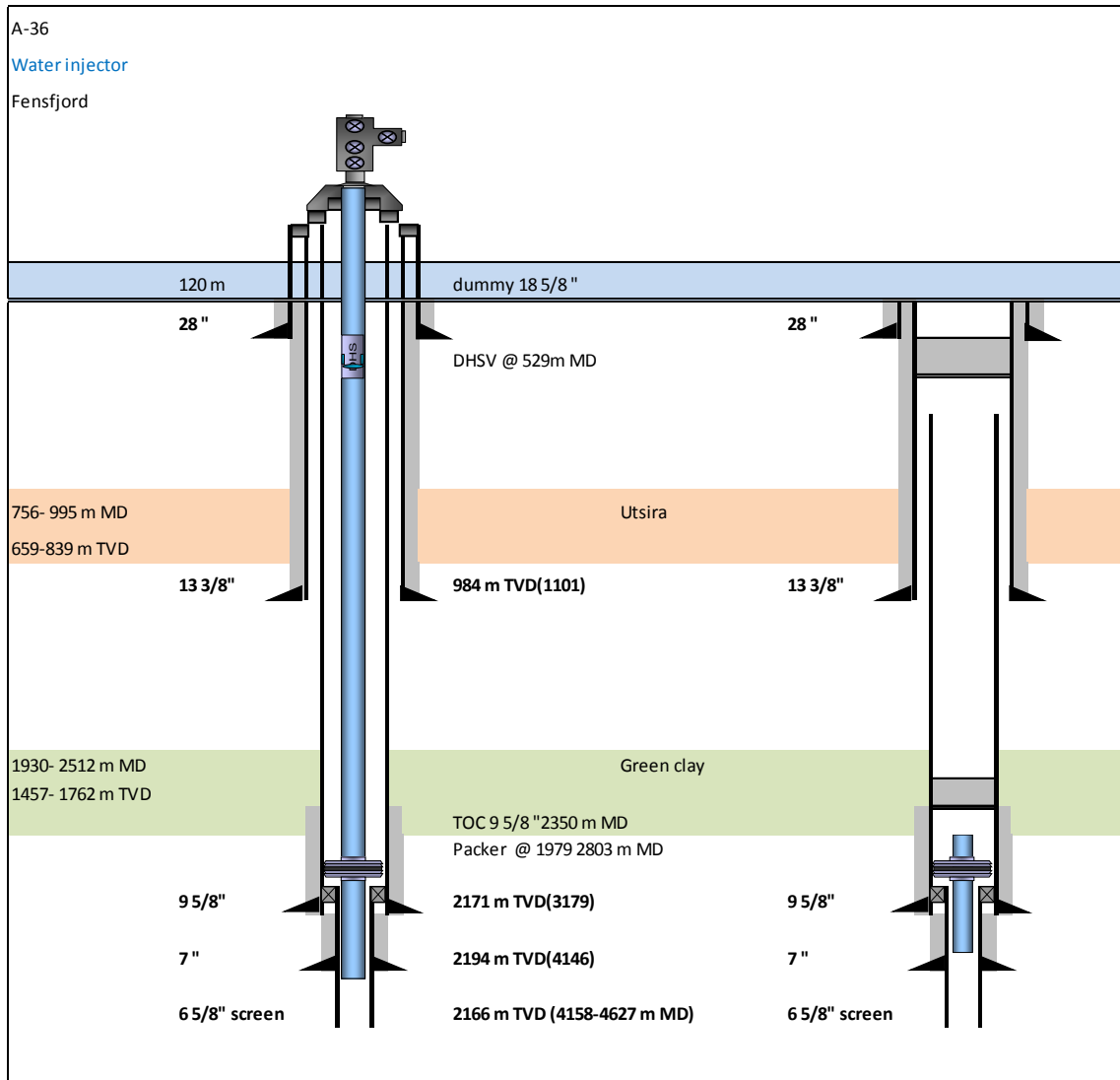


Figure 42: Well A-36: Water injector

Reference: 5.3.1.

Water injector without ASV. Saves one operational step before pulling the upper completion (tubing).

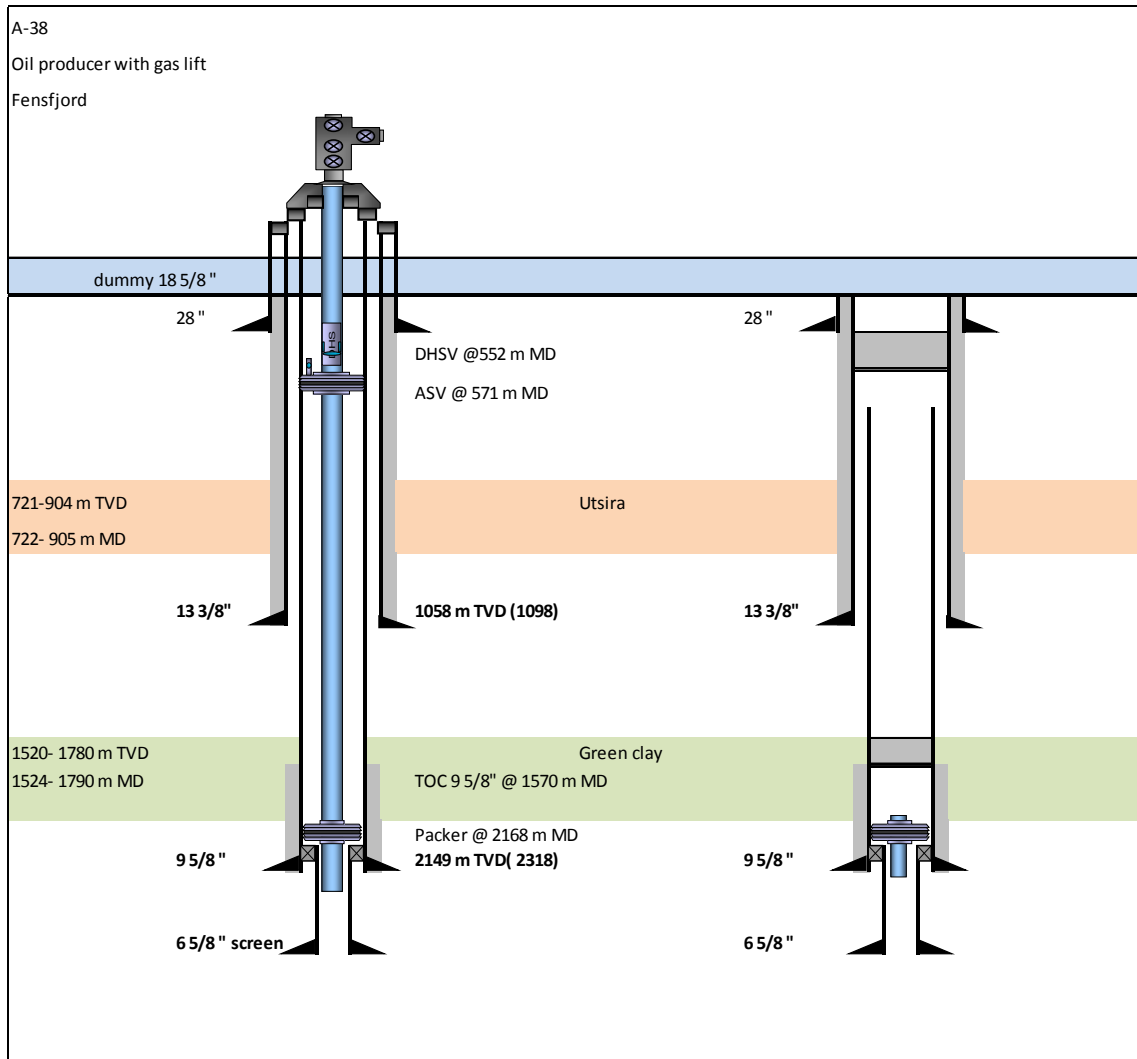


Figure 43: well A-38: Producer with gas lift

Reference: 5.3.1.

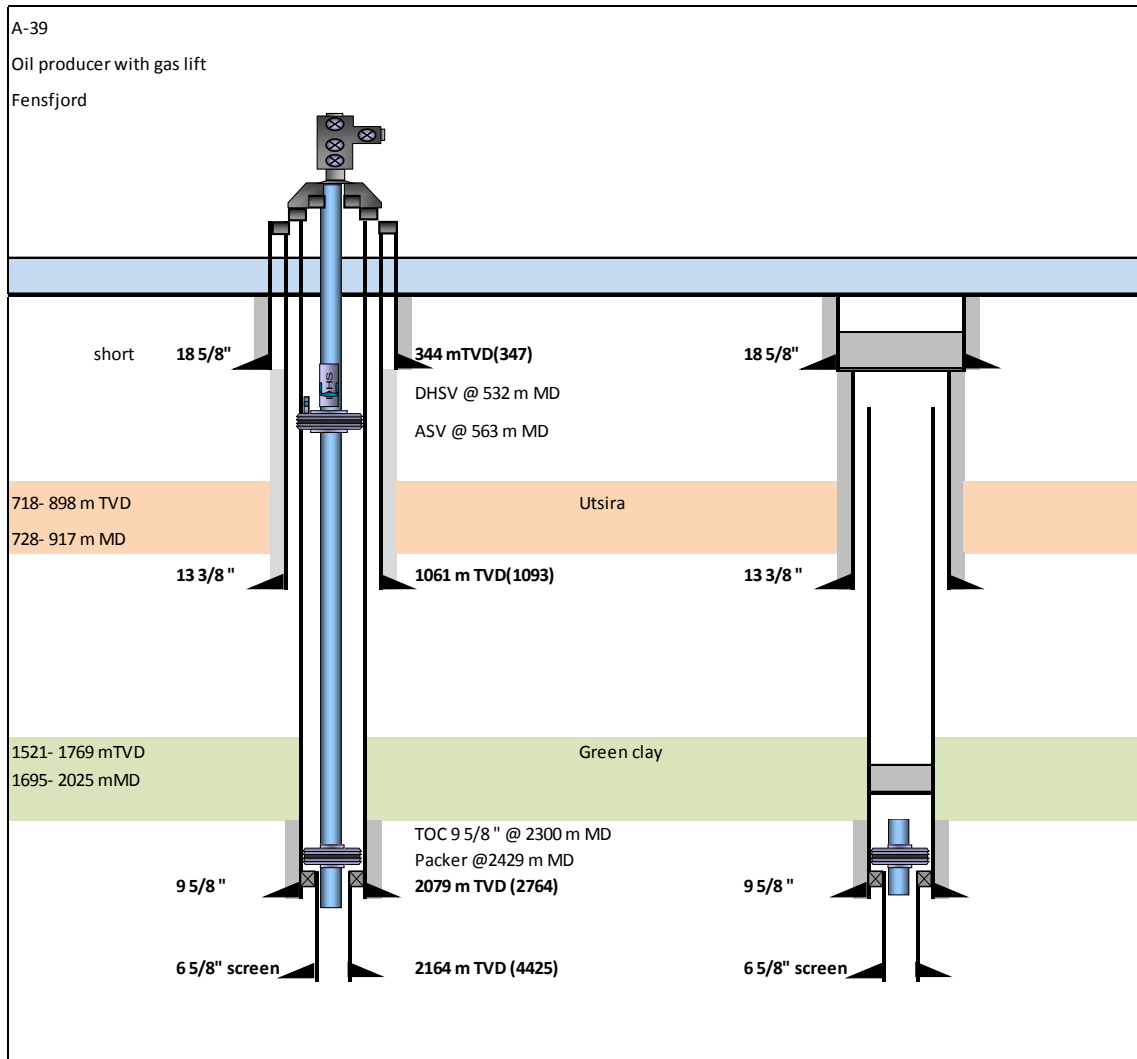


Figure 44: Well A-39: Producer with gas lift

Reference: 5.3.1.

Well A-39 got a short 18 5/8” casing which will require cutting the 13 3/8” before setting the environmental plug.

5.4 Utsira and Oligocene wells

There are four shallow wells on the Brage field which targets the shallow formations at Brage. There are two wells producing water from the Utsira formation for water injection, one injection well in the Oligocene sandstone and a cuttings injector in the Utsira formation. The two water producers in the Utsira formation has the same casing design, but the two others has an original casing design compared to the other wells at Brage, and needs to be dealt with individually.

5.4.1 Oligocene slope injector

The well A-15 was initially a production well. The well was reentered, and there were set two barrier plugs against the reservoir as shown in Figure 45 the well was then perforated to create contact with the permeable Oligocene formation. It now functions as an injector well. The operational sequence is only for setting the surface plug. The primary and secondary barrier is already installed, and the proposed method of P&A only concern P&A:

The proposed method for permanent P&A of A-15:

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor (If ASV is part of the completion)
- Pull upper completion. From DHSV to cut
- Retrieve tubing hanger
- Cut and pull 13 3/8"
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

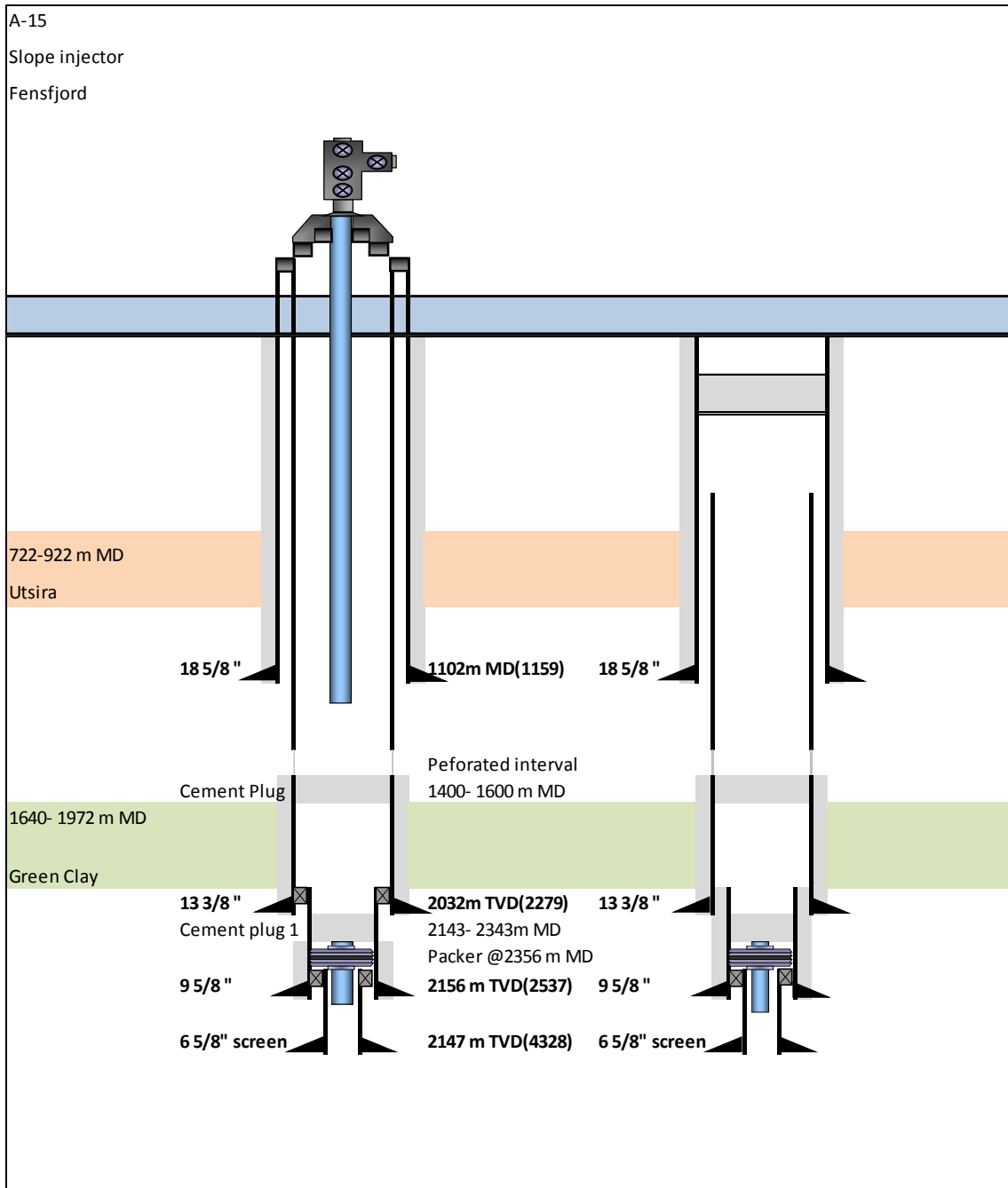


Figure 45: Well A-15: Oligocene slope injector

5.4.2 Utsira water producers

There are two water producers that targets the Utsira formation. The water that is produced from these wells A-24 and A-29 is reinjected into the reservoirs. The proposed method for P&A does not include intervention, nipple up BOP and pulled upper completion:

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Retrieve tubing hanger
- Log 18 5/8" prior to setting environmental plug
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

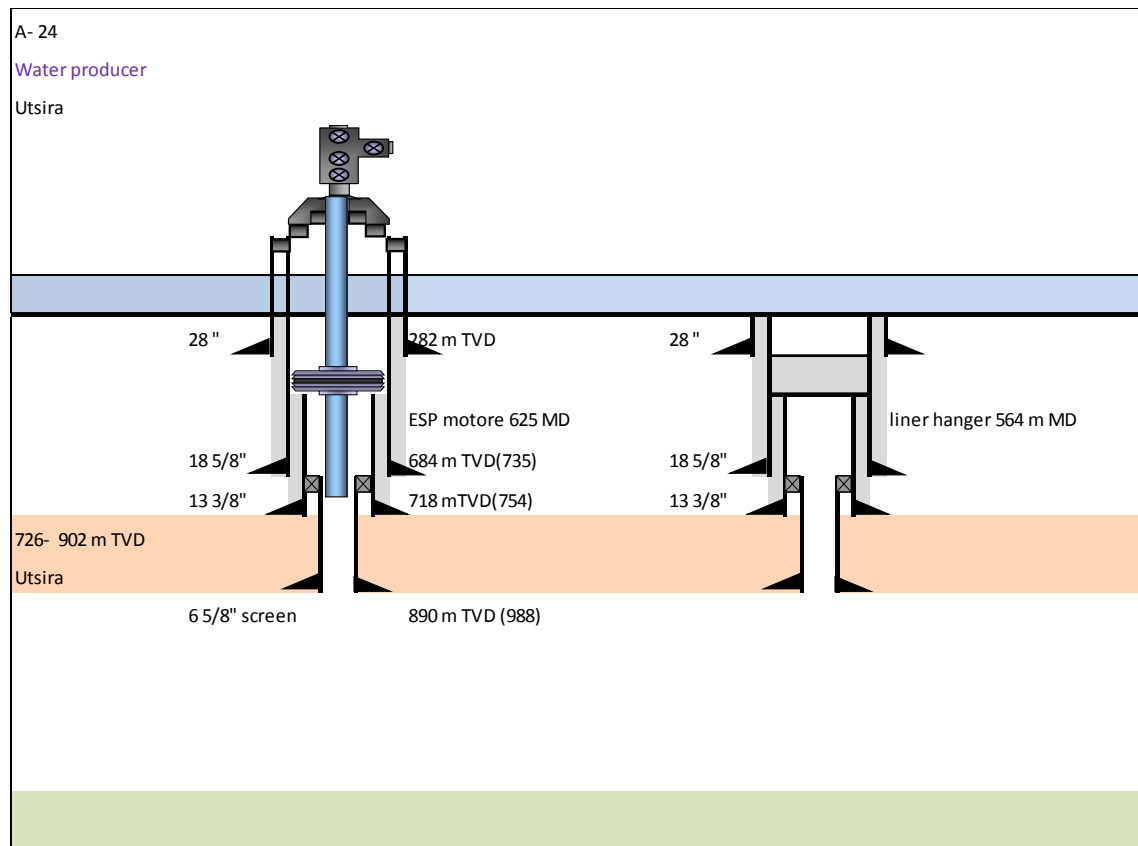


Figure 46: Well A-24: Utsira water producer

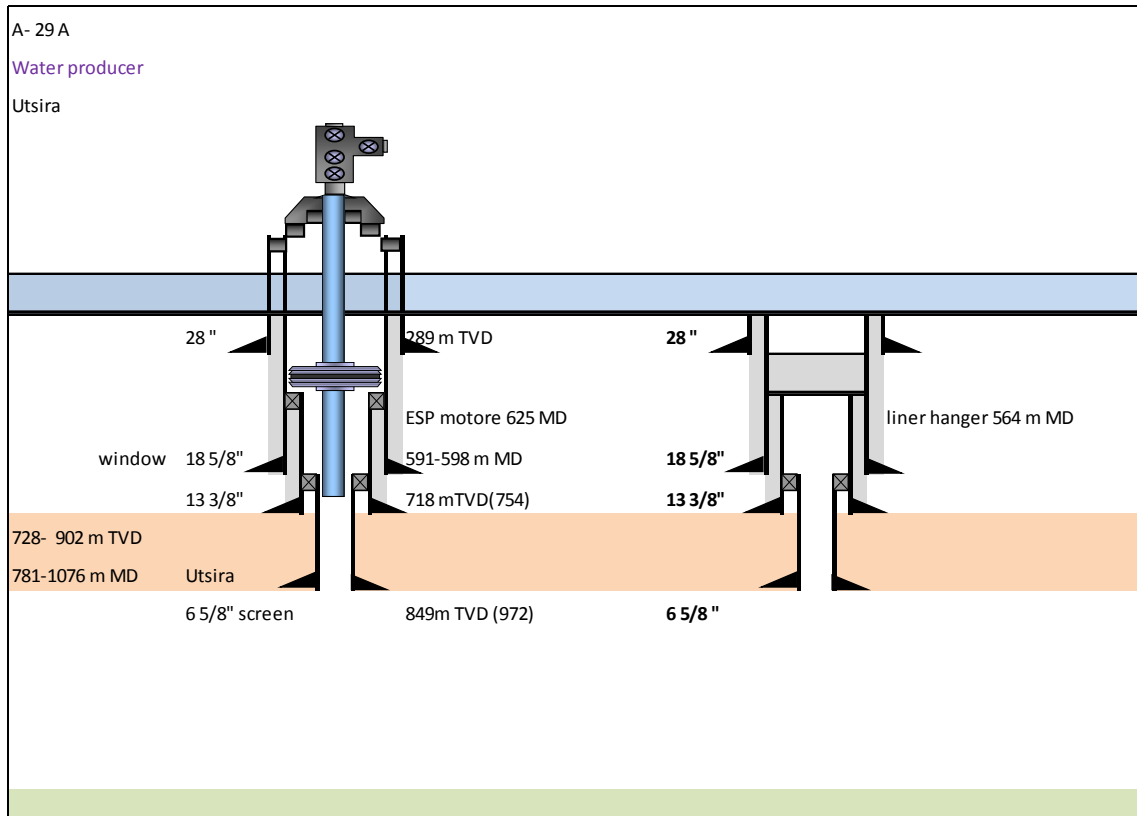


Figure 47: Well A-29: Utsira water producer

5.4.3 Cuttings injector

The proposed method for permanent P&A of the cuttings injector is:

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3.
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor (If ASV is part of the completion)
- Pull upper completion
- Retrieve tubing hanger
- Retrieve 10 3/4" tie-back casing
- Cut & Pull 13 3/8" shallow
- Log 18 5/8" prior to setting environmental plug
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

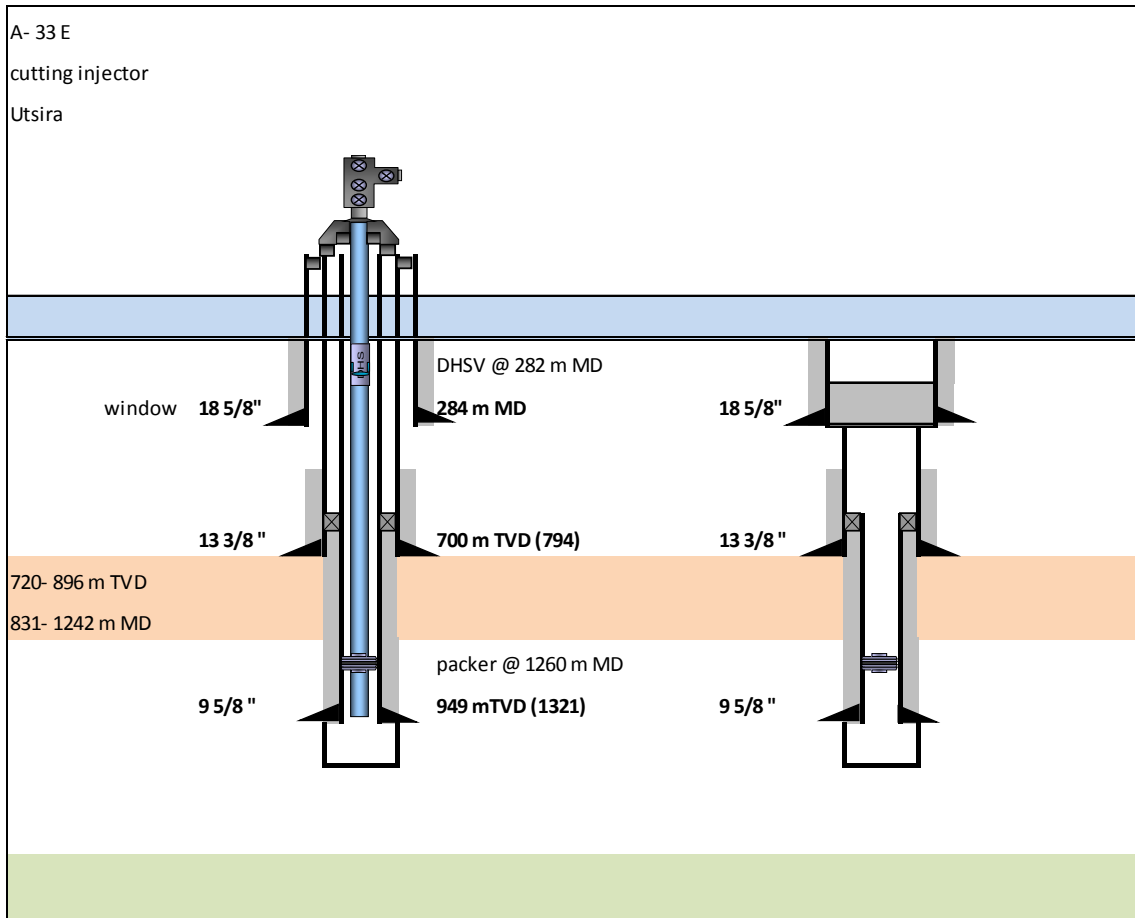


Figure 48: Well A-33: Utsira cuttings injector

5.5 Wells with a dual barrier plug set below the Hordaland formation

In well A-4, A-6 and A-8 the 13 3/8" casing shoe is set deeper than the bottom of the Hordaland green clay, with a 9 5/8" casing inside. These three wells needs a different Permanent P&A solution. Experience have shown that it is hard to recover the 9 5/8" casing because of all the dirt between the 9 5/8" and 13 3/8" casings. It will be too time consuming to recover 9 5/8" and set the cement plug inside 13 3/8" against the green clay formation. Therefore it is better to set cement plug deep in the 9 5/8". We assume good cement behind the 9 5/8" casing. In old wells on the NCS that is not always the case.

5.5.1 Pre-drilled with 13 3/8 "casing shoe below green clay layer

A-4 and A-6 are tied back to the platform in the same way as the other pre-drilled well. The issue with these two wells is that the both the 9 5/8" and 13 3/8" goes through the green clay. A-1 had the same design, but was sidetracked in 2008.

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3.
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor
- Pull upper completion
- Set shallow 9 5/8" barrier plug before removing conductor
- Cut 10 3/4" tie back casing at 50 m MD and pull out of hole
- RIH and release and recover remaining 10 3/4" tie-back string from seabed
- Cut 13 3/8" tie-back at 50 m MD and pull out of hole
- RIH and release and recover remaining 13 3/8" tie-back string from seabed
- Pull tie-back conductor with internal wellhead latch from seabed
- Run tie-back conductor with external wellhead latch to seabed
- Retrieve shallow plug
- Log 9 5/8" below 13 3/8" shoe
- RIH with mechanical plug and pressure test

- Set dual cement plug
- Tag cement
- Remove tubing head
- Cut and Pull 9 5/8" shallow
- Cut and pull 13 3/8" shallow
- Set environmental plug
- Tag plug
- Remove conductor and casing strings a few meters below seabed

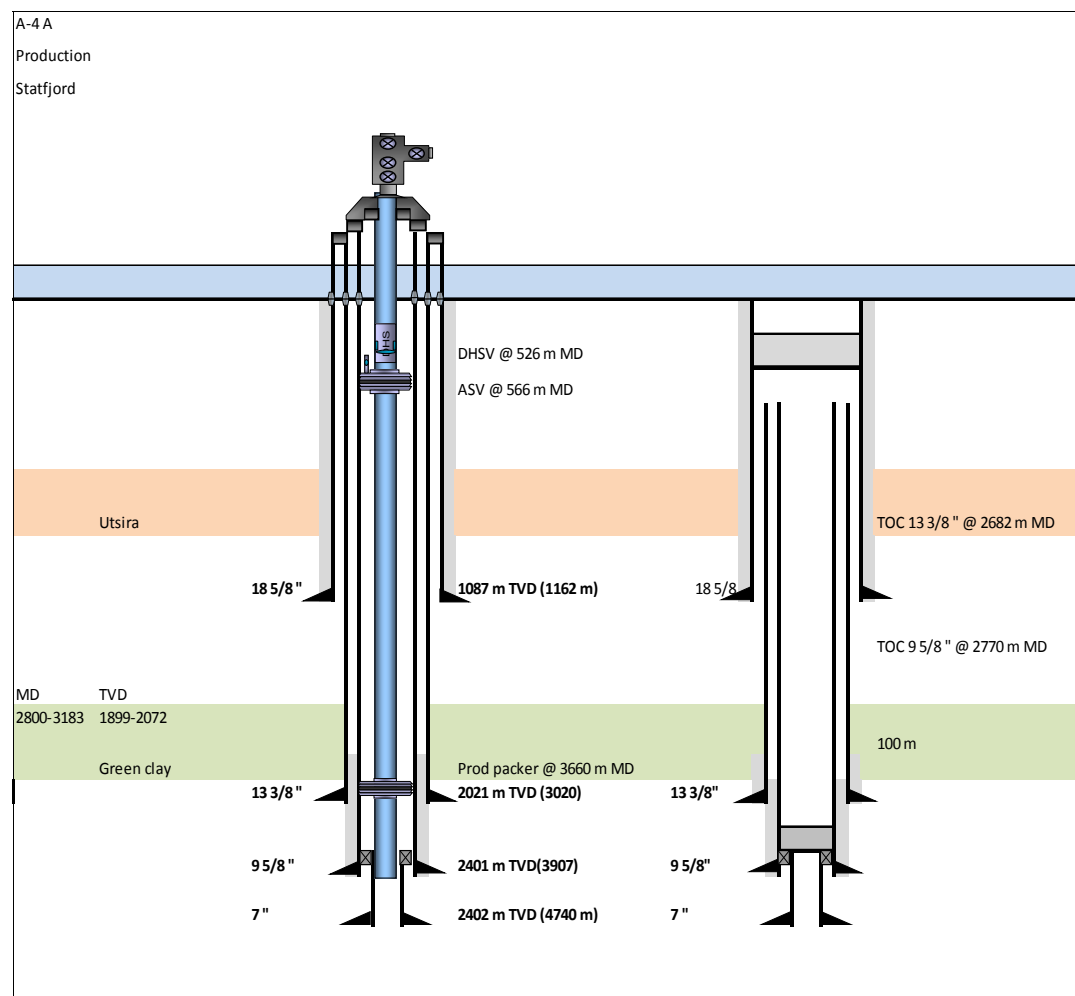


Figure 49: Well A-4: Pre-drilled with 13 3/8" casing shoe below green clay layer

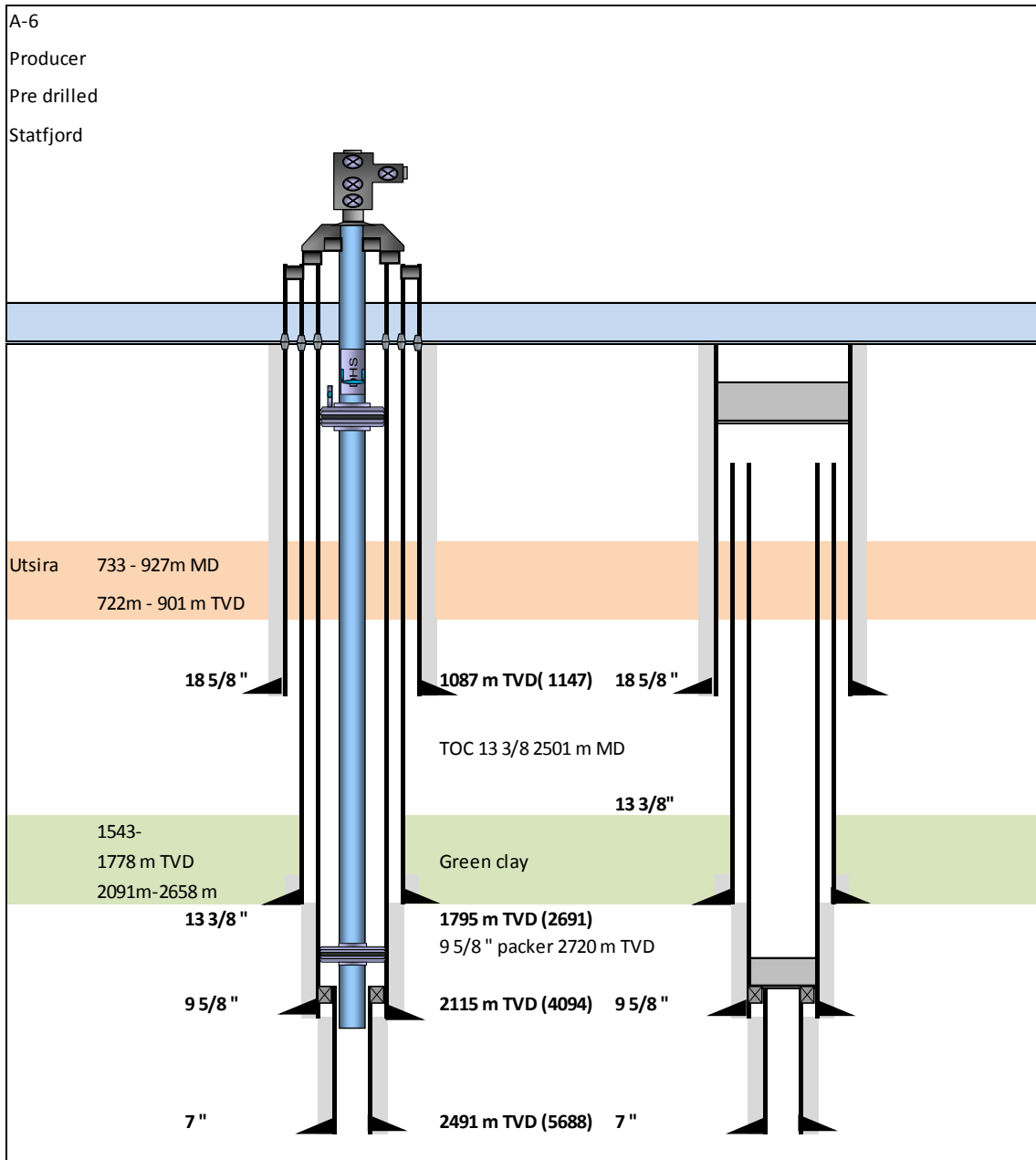


Figure 50-Well A-4: Pre-drilled with 13 3/8" casing shoe below green clay layer

5.5.2 A-8 with 13 3/8" casing shoe below green clay layer

A-8 is the only well left in the field with this casing design. Other wells with the same casing design has been plugged and then sidetracked.

- Intervention
 - Rig up wireline and set two barrier against the reservoir. Described in detail in chapter 3.3.
- Remove XT (offline)
- Nipple up BOP/riser and perform pressure test
- Pump open shallow plug
- Cut and pull above ASV and release ASV anchor
- Pull upper completion
- Set shallow barrier plug
- Retrieve tubing hanger
- Retrieve shallow barrier plug
- Log 9 5/8" at 4500 m MD
- Set mechanical plug
- Set a dual cement plug at 4500 m MD
- Cut & Pull 9 5/8" casing shallow
- Cut & Pull 13 3/8" casing shallow
- Set mechanical plug and pressure test the plug
- Set environmental plug
- Tag environmental plug
- Remove conductor and casing strings a few meters below seabed

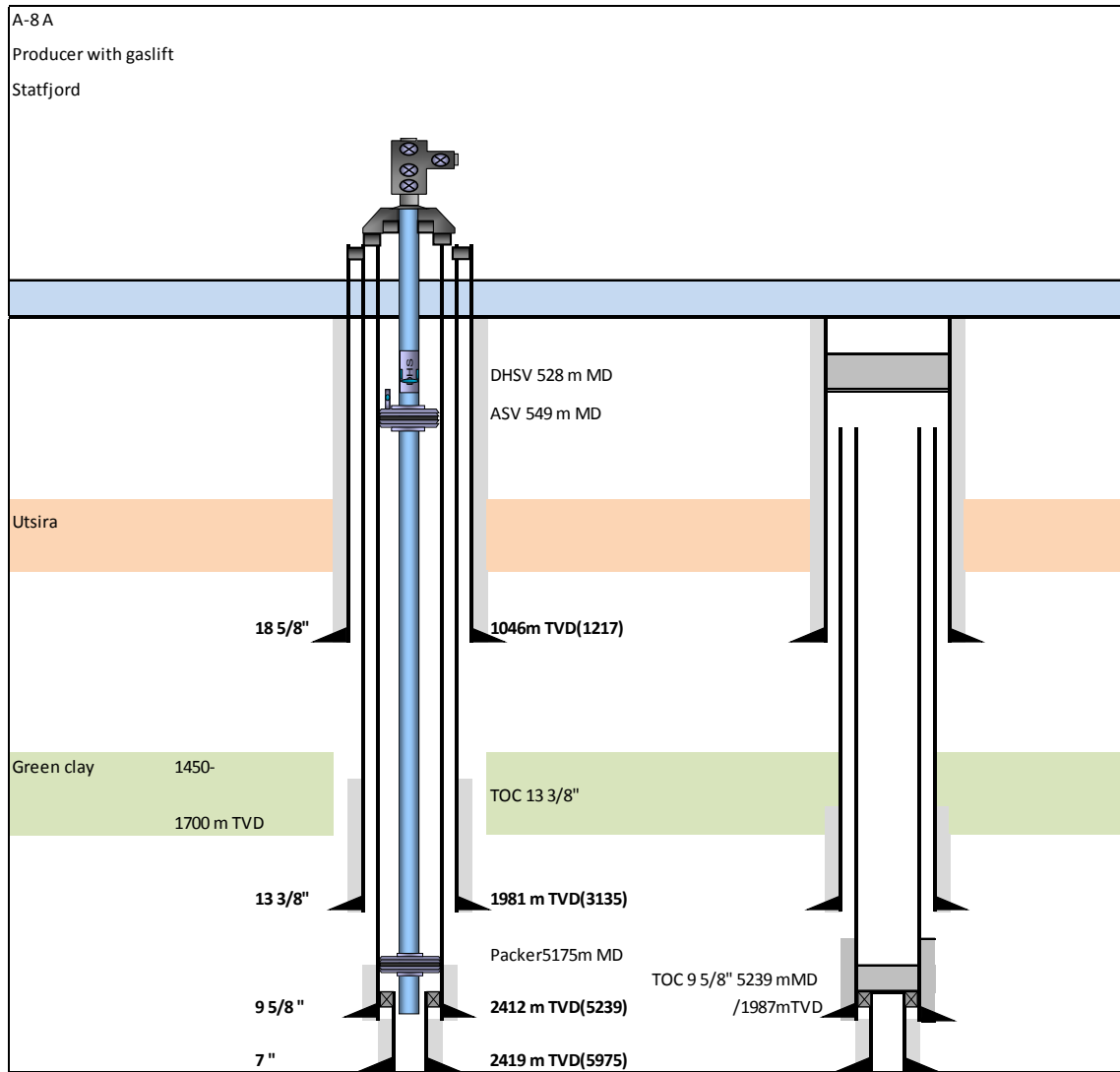


Figure 51: Well A-8: Producer with gas lift

6 Time estimation

This chapter shows the estimated time for permanent P&A for the different well types at Brage. The input data are gathered from previous experience Wintershall has from slot recovery at Brage, and abandonment of Murchison on the British sector and expert opinion. Table 2 below gives an overview of the different operations required for permanent P&A:

Well Type		Skid rig	Intervention	Retrieve ASV	Pull upper completion	Set shallow barrier plug	Retrieve Tie-back casing	Log prior to setting dual plug	Set and test dual barrier plug	Remove internal conductor	Nipple down tubing head	Set dual plug at 4500 m M/D	Retrieve shallow barrier plug	Cut and pull 9 5/8" shallow	Set environmental plug	Conductor removal	
A-1	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-2	Prod.	x	x	x	x		x	x	x		x	x	x	x	x		
A-3	Water inj.	x	x		x	x		x	x	x		x	x	x	x		
A-4	Prod.	x	x	x	x	x			x	x	x	x	x	x	x		
A-5	Prod.	x	x	x	x	x		x	x	x		x	x	x	x		
A-6	Prod.	x	x	x	x	x			x	x	x	x	x	x	x		
A-7	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-8	Prod.	x	x	x	x	x			x	x	x	x	x	x	x		
A-9	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-10	Prod.	x	x	x	x	x		x	x	x		x	x	x	x		
A-11	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-12	Water inj.	x	x		x		x	x		x		x		x	x		
A-13	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-14	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-15	Oligo.	x	x	x	x				x				x	x	x		
A-16	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-17	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-18	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-19	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-20	Prod.	x	x	x	x	x		x		x		x	x	x	x		
A-21	Water inj.	x	x	x	x		x	x		x		x		x	x		
A-22	Water inj.	x	x		x	x	x			x		x		x	x		
A-23	Prod.	x	x	x	x	x		x		x		x		x	x		
A-24	Ut. prod.	x	x		x				x					x	x		
A-25	Prod.	x	x	x	x		x	x		x		x		x	x		
A-26	Water inj.	x	x		x		x	x		x		x		x	x		
A-27	Water inj.	x	x	x	x		x	x		x		x		x	x		
A-28	Prod.	x	x	x	x	x		x		x		x		x	x		
A-29	Ut. prod.	x			x				x					x	x		
A-30	Prod.	x	x	x	x		x	x		x		x		x	x		
A-31	Prod.	x	x	x	x	x		x		x		x		x	x		
A-32	Water inj.	x	x	x	x	x		x		x		x		x	x		
A-33	Cutt. inj.	x	x		x	x			x			x		x	x		
A-34	Prod.	x	x	x	x	x		x		x		x		x	x		
A-35	Gas inj.	x	x	x	x	x		x		x		x		x	x		
A-36	Water inj.	x	x		x		x	x		x		x		x	x		
A-37	Prod.	x	x	x	x	x		x		x		x		x	x		
A-38	Prod.	x	x	x	x		x	x		x		x		x	x		
A-39	Prod.	x	x	x	x		x	x		x		x		x	x		
A-40	Prod.	x	x	x	x	x		x		x		x		x	x		
	P10	4	69	51	20	6	56	11	62	128	38	96	9	24	24	61	84
	P50	6	99	73	28	8	80	16	71	183	54	137	13	30	30	87	120
	P90	9	128	94	36	10	104	21	114	237	70	178	17	36	36	113	156

Table 2 - Operation time for the different wells at Brage

In this chapter, there will be presented a forecast of the total duration of the P&A operation. A Monte Carlo simulation has been done for the P&A operation of the different wells at Brage. The method will give a probabilistic outcome of the P&A operation for Brage, without any unexpected events, such as broken tubing or stuck casing.

First, there needs to be established an appropriate model. It is important to specify which items to include/exclude from the model and the level of detail in the model. Data gathering is the hardest part, the data set should be large enough to collect all possible outcome. The choice of distribution shape for input parameters is not critical for well-time forecasting. According to the central limit theorem, the sum of individual distributions with any shape will lead to a final distribution that has a mean close to the sum of the mean of individual distributions and a variance close to the sum of the variance of individual distributions, and a shape which is approximately normal [23]. Therefore, put effort and time in selecting appropriate mean and spread rather than discussing the distribution shape. Sample input distribution, choose the number of iterations required. For this thesis the simulation is done with 30 000 iterations. The larger number of iterations, the more accurate result. The final part is interpreting the results: a set of probability distribution curves or histogram for each forecast quantity. The result needs to be evaluated and corrected if there are any mistake.

The results are posted below. Matlab was the software-programming tool of choice, and the result of probabilistic time estimation is presented as a probability-density function (PDF) and a cumulative-distribution function (CDF). Both curves are given as a function of time. Time distributions were made for all the different well categorize.

The y-axis on the probability-density function curve presents the occurrence probability corresponding to each value of outcome. The y-axis in the CDF curve shows probability for finishing the operation below a certain time-limit.

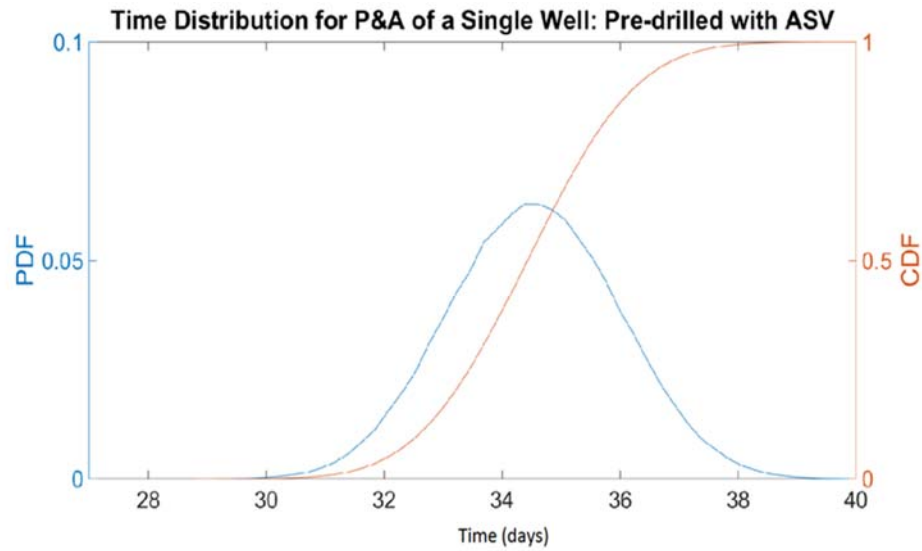


Figure 52: Time distribution for P&A of a single: Pre-drilled with ASV

Figure 52 shows the distribution for P&A of a Pre drilled well with ASV, as shown in chapter: 5.1. The P 50 value for a single like this is 34, 5 days.

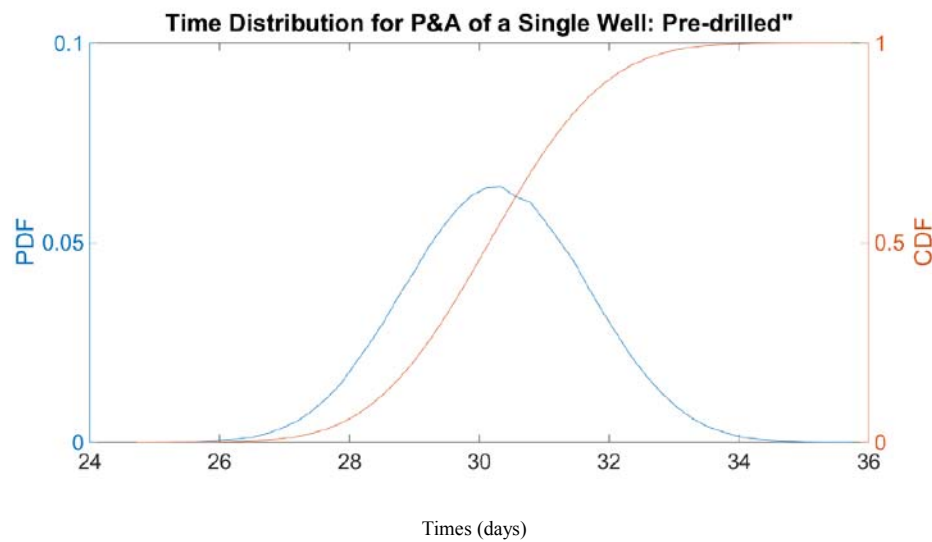


Figure 53: Time distribution for P&A of single well: Pre-drilled

Figure 53 shows the distribution for P&A of a pre-drilled well without ASV, as shown in chapter: 5.1 without the one operational sequence regarding releasing the ASV. The distribution is shifted to the left, and the P 50 value is 31, 5 days.

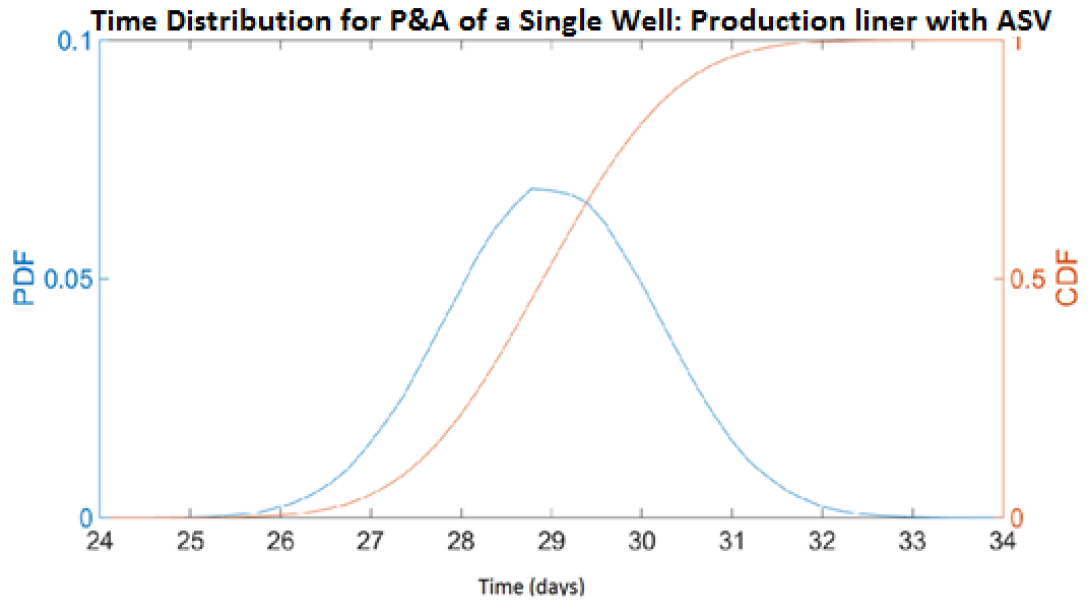


Figure 54: Time distribution for P&A of a single well: production liner with ASV

Figure 54 shows the distribution for P&A of a single well with production liner and tie-back casing with ASV, as shown in chapter: 5.2. This group consist of half of the wells at Brage. The P 50 value for a well with a production liner with ASV is 29 days.

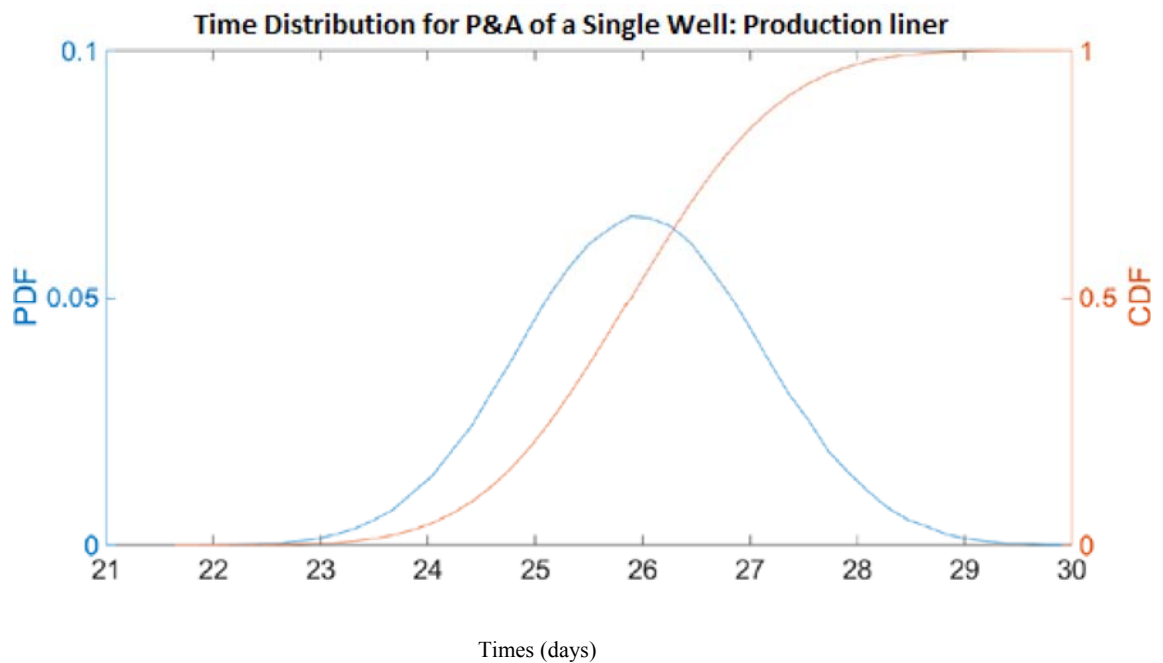


Figure 55: Time distribution for P&A of single well: Production liner

Figure 55 shows the distribution for P&A of a single with 9 5/8" liner without ASV, as shown in chapter: 5.2 without the operational step regarding releasing the ASV. The P 50 value for a well with a production liner is 26 days.

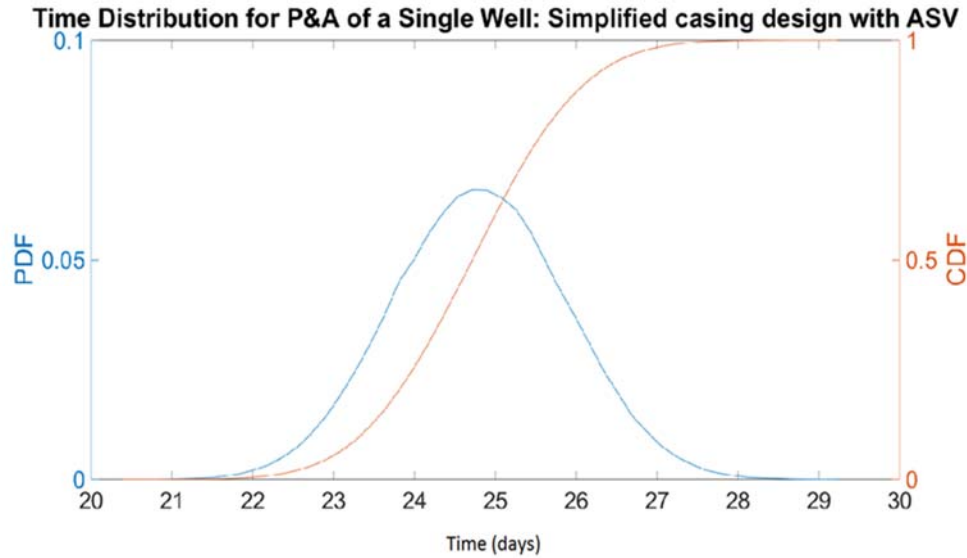


Figure 56: Time distribution for P&A of a single well: Simplified casing design with ASV

Figure 56 shows the time distribution for P&A of a well with simplified casing design with ASV, as shown in section 5.3. The P 50 value for a single well like this 24, 8 days.

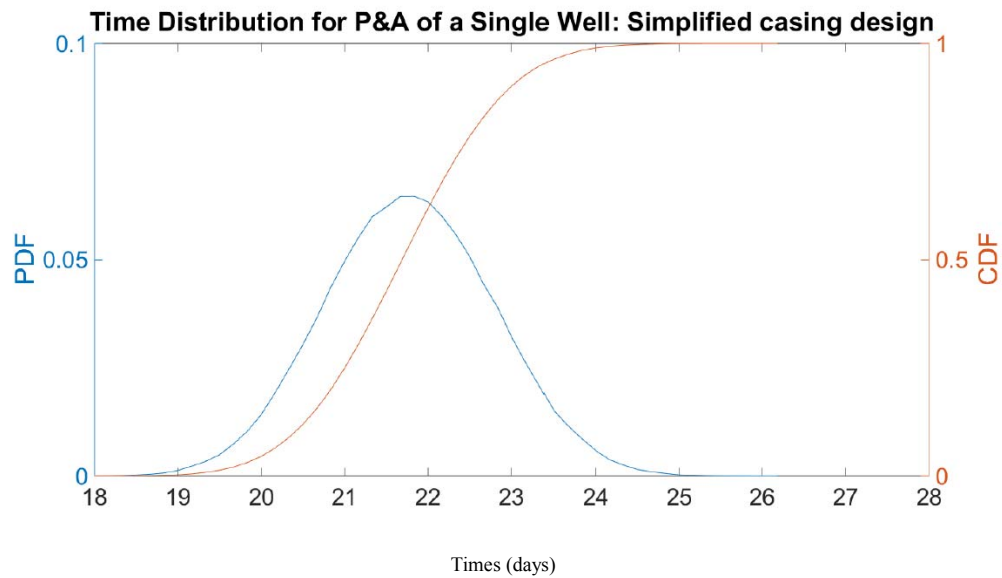


Figure 57: Time distribution for P&A of a single well: Simplified casing design

Figure 57 shows the time distribution for P&A of a well with simplified casing design without ASV, as shown in section 5.3. The P 50 value for a single well like this 21.8 days.

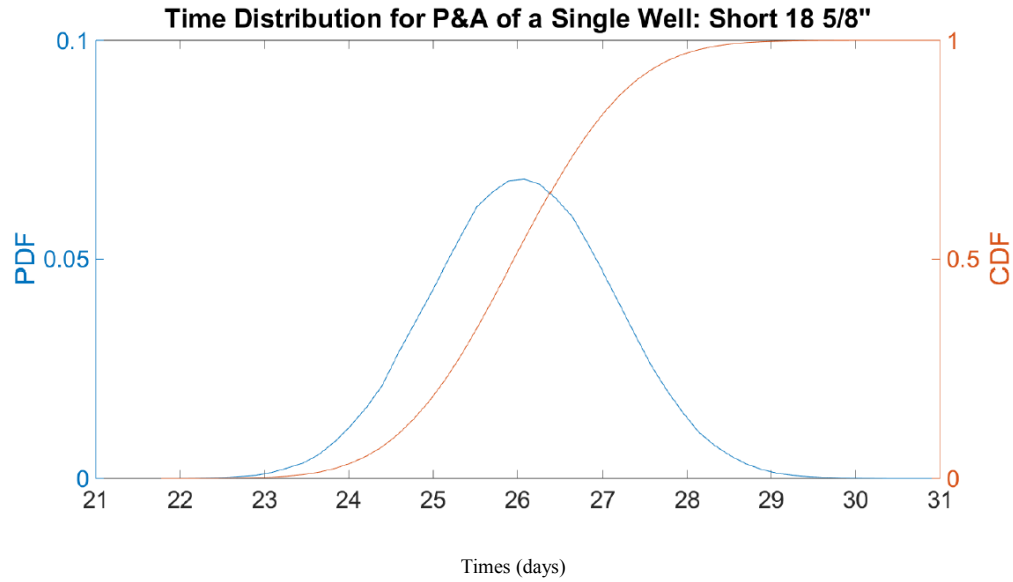


Figure 58: Time distribution for P&A of a single well: Short 18 5/8"

Figure 58 shows the distribution for a single well with a short 18 5/8" casing, as shown in chapter: 5.3 but also require cutting of the 18 5/8" casing before setting environmental plug. The P 50 value for these wells are 26 days.

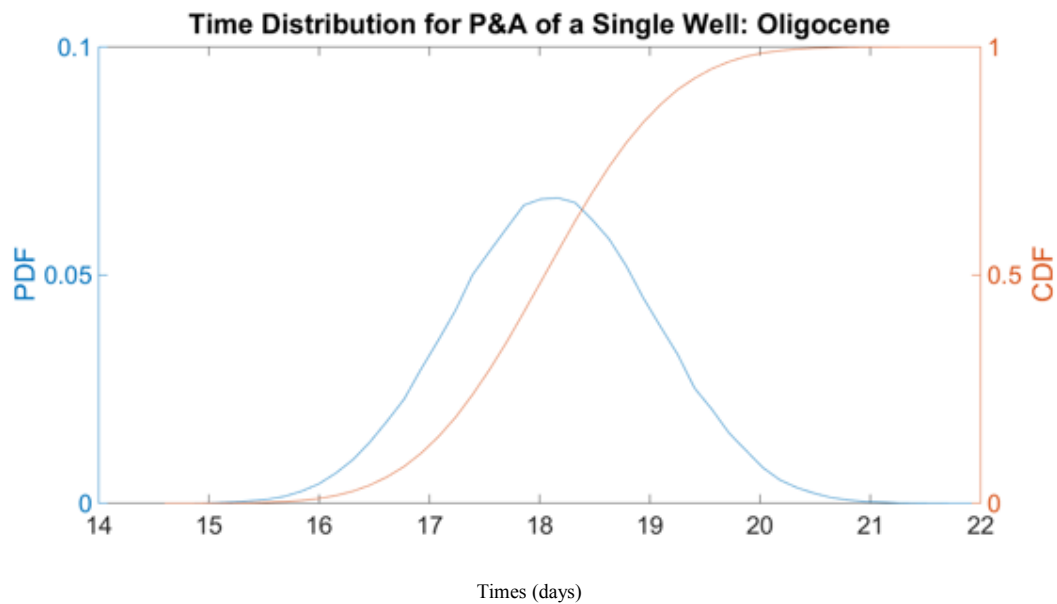


Figure 59: Time distribution for P&A of a single well: Oligocene

Figure 59 shows the distribution for the Oligocene injector, as shown in chapter: 5.4.1. The P 50 value for this well is 18 days.

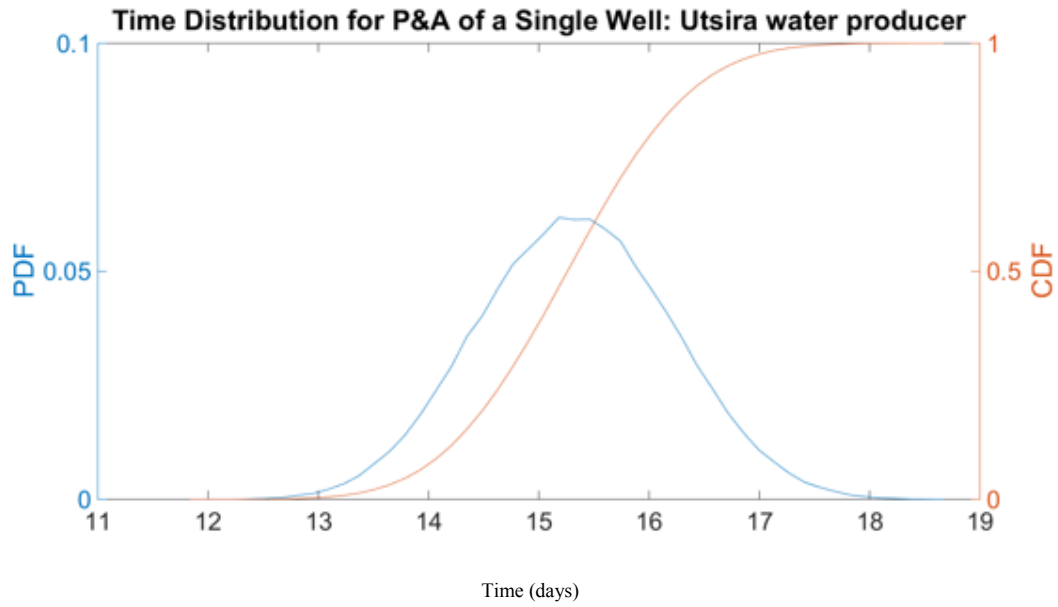


Figure 60: Time distribution for P&A of single well: Utsira water producer

Figure 60 shows the distribution for the Utsira water producers, as shown in chapter: 5.4.2. The P 50 value for this well is 15 days.

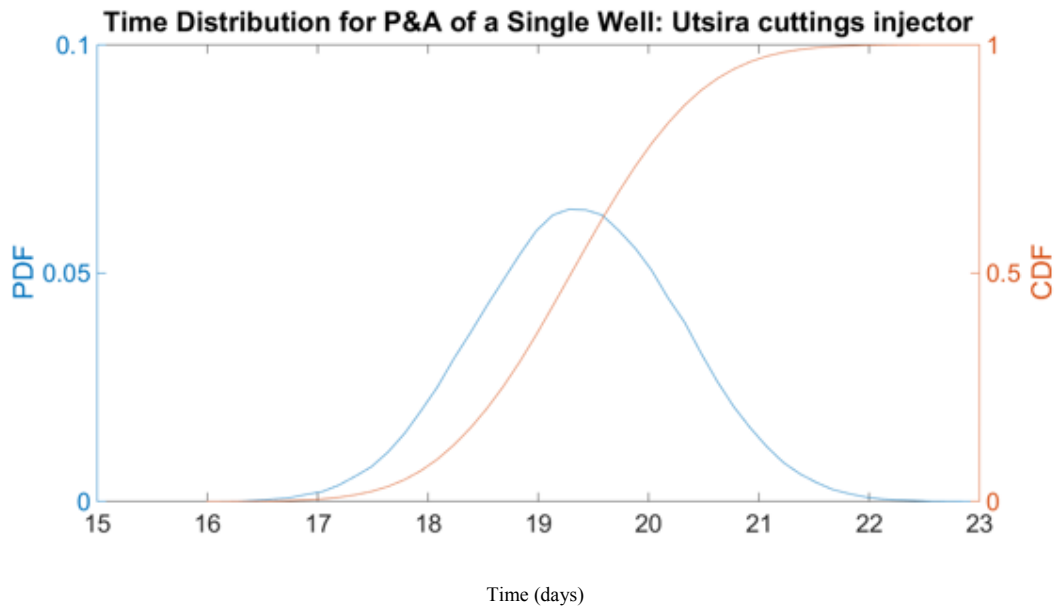


Figure 61: Time distribution for P&A of single well: Utsira cuttings injector

Figure 61 shows the distribution for the Utsira cuttings injector, as shown in chapter: 5.4.3. The P 50 value for this well is 18 days.

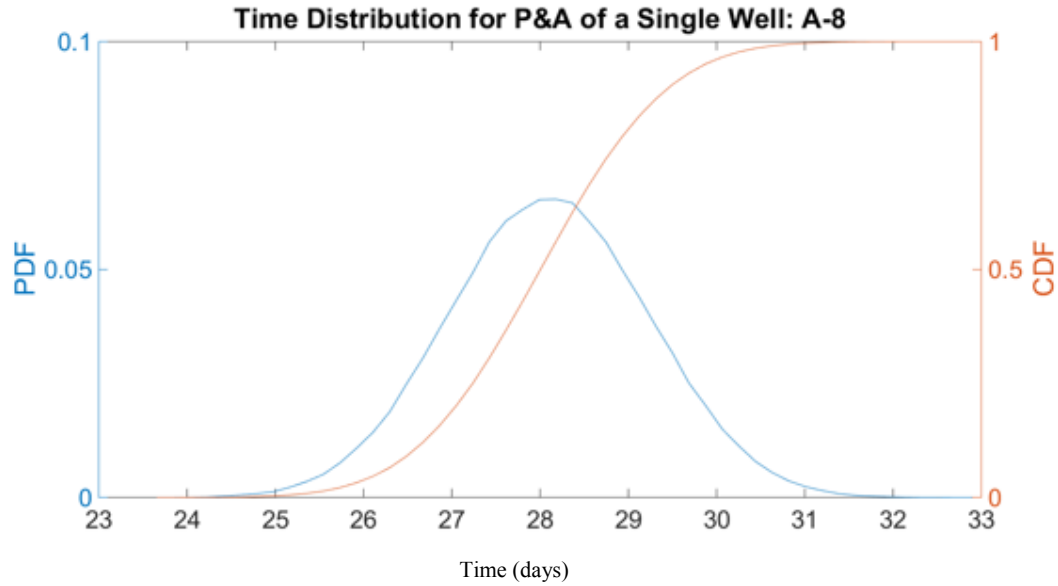


Figure 62: Time distribution for P&A of a single well: A-8

Figure 62 shows the distribution for the A-8 well, as shown in chapter: 5.5.1. The P 50 value for this well is 35 days.

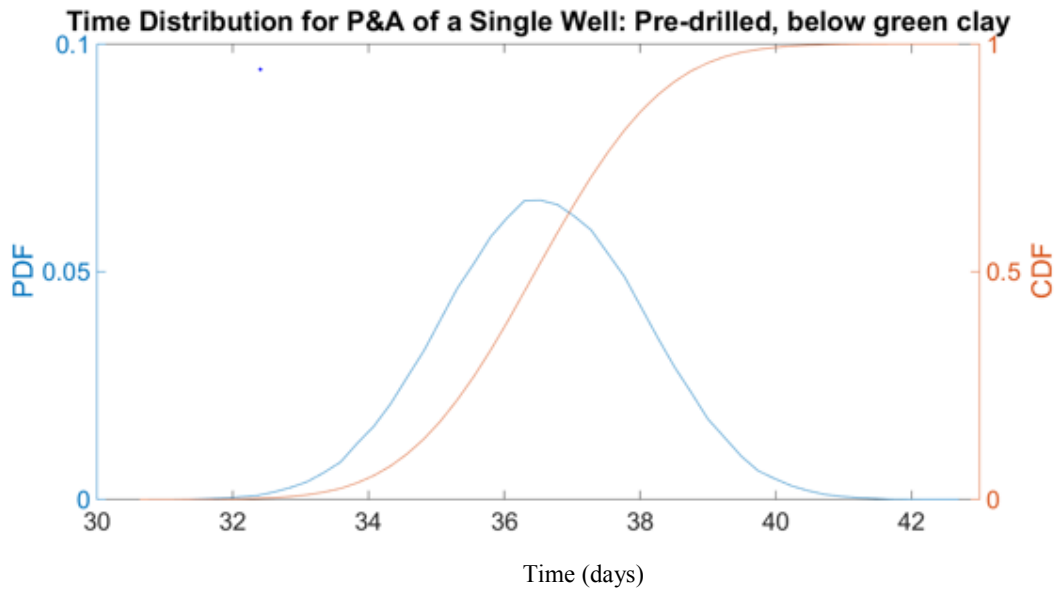


Figure 63: Time distribution of a single well: pre-drilled, below green clay

Figure 63 shows the distribution for the pre-drilled with two casings shoe below Hordaland green clay layer, as shown in chapter: 5.5.2. The P 50 value for this well is 28 days.

Values of P10, P50 and P90 will be extracted from these curves. The data is presented in the table 3 below.

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

	ASV	Nr. of wells	P10 (days)	P50 (days)	P90 (days)	Min (days)	Max (days)	Standard deviation
Pre-drilled	Yes	2	32,7	34,5	36,4	28,7	40,5	1,42
Pre-drilled	No	1	29,7	31,5	37	29,7	37	1,37
Production liner	Yes	20	27,5	29	30,5	24	34	1,15
Production liner	No	1	24,6	26	27,4	21,3	30,8	1,09
Simplified csg. Design	Yes	4	23,5	24,8	26,2	20,3	29,3	1,06
Simplified csg. Design	No	3	20	21,8	23	18	26,2	1,005
Short 18 5/8"	Yes	2	24,6	26	27,5	20,9	30,4	1,073
Oligocene injector	No	1	16,9	18,12	19,3	14,5	22,7	0,9
Uitsira producer	No	2	14,2	15,3	16,5	11,8	18,7	0,877
Cuttings injector	No	1	17	18	19	14,6	21,5	0,9
Pre drilled cement 9 5/8"	Yes	2	33,8	35,7	37,6	29,9	42,3	1,46
A-8	Yes	1	26,6	28	29,5	23,3	32,8	1,13

Table 3- Statistical properties of the forecast Result

6.1 P&A of the Brage field

When P10, P50 and P90 was found for all the different well types at the Brage field, a distribution were made for permanent P&A of the entire field. The distribution is given in the figure 64 below

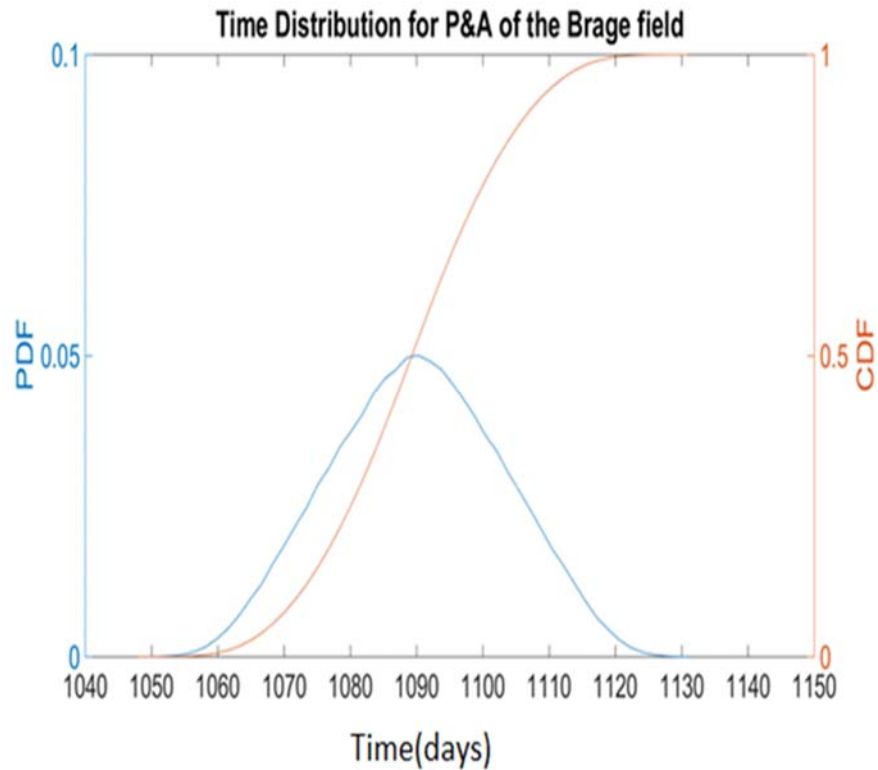


Figure 64- Time distribution for the P&A operation of the Brage field

Results predict that 50 % of the outcomes are smaller than 1090 days, and after performing 30 000 iterations, the total time went from 1047 as the lowest expected time and all the way up to 1131.

Statistical Parameter	Total (days)
P10	1072
P50	1090
P90	1107
Min	1047
Max	1131
Standard Deviation	12,95

Table 4- Statistical parameters for P&A of Brage

7 Discussion

The predicted value for permanent P&A in this thesis is almost 3 years. The estimation is done without taking unexpected events into account, and some wells will be reentered and differ from the once showed in this thesis. The actual method of choice for the P&A operation may change in future due to new technology, because of the decline in production rates on many of the oldest fields on NCS the search for new technology is increasing. A lot of service companies sees a huge potential in providing the operators with new and ground breaking technology. If some of the technologies listed in this chapter becomes commercial, it has the potential to reduce the cost of decommissioning a field significantly.

The discussion in this thesis will be around the validity of the time estimation made in chapter 6, and other factors that might change the final time of P&A.

7.1 Unexpected events

The time estimate done in this thesis is done without taking into account unexpected events and non-productive time (NPT). Traditionally in drilling engineering time estimates were performed by deterministic approach. The advantage with a deterministic approach is simplicity, clear assumptions and transparent communication of the result. The short comings of the deterministic approach: has a high degree of optimistic bias about the result and does not reflect the full range of possible outcomes. The benefit with a probabilistic approach is that it captures the range of possible outcomes. It also gives a greater understanding of the effect of unexpected events [24].

When unexpected events and non-productive time is taken into account, the probability distribution will be shifted to the right and widen the range of possible outcomes [25]. Meaning the operation is more likely to take longer time and there are more uncertainties in relation to the duration of the operation. This will reflect in an increase in the Standard deviation, a low standard deviation indicates that most data points are close to the mean value.

Brage is an old platform which increases the risk for failures in the equipment, which eventually results in non-productive time. When adding risks to the model, it is necessary to know the probability of a given event to happen, and the impact of the event (hours of non-productive time). Since Brage is a fixed installation the impact of weather is less than for a floating rig. There has been very little problem regarding pulling of tubing at Brage in the

past. Hydrocarbon in the annulus has not been a big problem. There is usually a correlation of events between different wells on the same field, they tend to have the same problems [25]. Monte Carlo simulation treats every well individually.

The effect of learning should also be taken into account, when performing a time estimation. For instance there are 21 wells at Brage with the same casing design, production liner with 10 3/4" tie-back casing. Studies has shown that the plug and abandonment time has been significantly reduced as a result of learning [25]. When the effect of leaning is added the probability distribution will shift to the left, meaning the later wells will most likely be P&A'd quicker than the first wells.

Rushmore is a large database that collects, analyzes and publishes offset well data for participating operators in the oil industry. Based on data from P&A performed on 26 platform wells on the NCS the percentages of productive time, none productive time and wait on weather was found. It is shown in figure 65

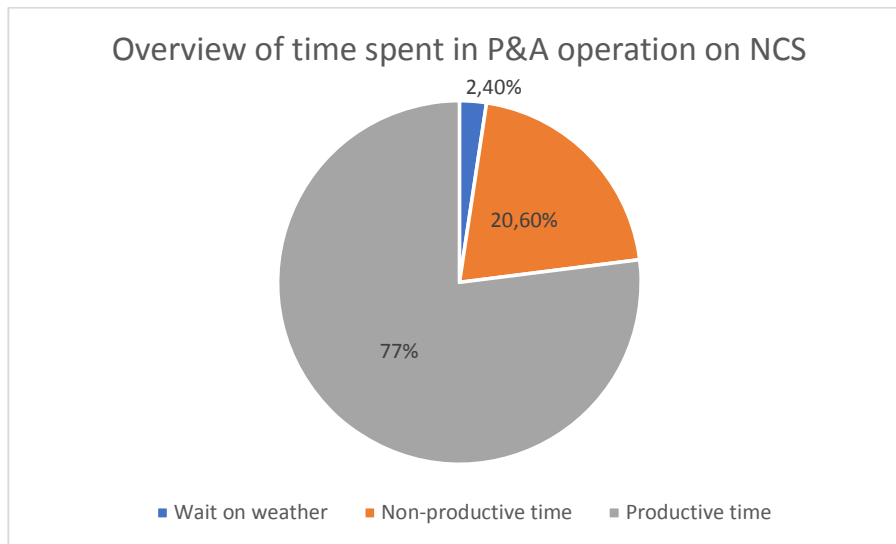


Figure 65- Overview of time spent on WOW, NPT and Productive time based on data from Rushmore

7.2 Technology

The P&A operation proposed in this thesis is done with existing technologies. The oil and gas industry is a very conservative industry and can be very hesitant to implement new technologies and methods. A lot of the methods that is on the drawing board at the moment has the potential to reduce the total time of P&A operation significantly. Challenges with establishing a new method is not only to find a good way for sealing off the formation, it also has to be easy to verify the plug. Due to the P&A plug wave that is expected in the coming years, there is a major opportunity for the service companies to come up with new ground breaking technology.

New technology will reduce the time of the operation. If the tubing and casing can be left in hole heavy lifts and swarf handling will be avoided, which will make the operation safer. In the following chapters, some new technologies will be presented. Some of them are in the final stage and currently doing field testing, others are still on the research stage. If these methods become commercial they will significantly reduce the cost related to P&A.

7.2.1 Steel pipe removal by controlled corrosion reaction

SINTEF is looking into using a controlled corrosion reaction to remove steel pipes. SINTEF was contacted by Statoil to investigate whether steel pipes could be removed with an electrochemical reaction. As with creeping formation the scientist is looking to utilize a mechanism that is a problem during drilling and the lifetime of the well, too permanently P&A the well. There are several ways to speed up the corrosion process for example chemical and electrochemical dissolution.

Apply current in an electrical circuit with the casings as one of the electrodes in order to accelerate anodic dissolution of the pipe. This solution was tested in the lab, assuming wireline being able to apply 10 kW, 1m of 7" tubing was dissolved within 1 day [26].

Another way of corroding the casing is to introduce aggressive fluids like HCL or H₂SO₄ in the well. The lab result showed that it took 8 days to remove a 7" tubing. The lab test was done with a temperature at 60 degree Celsius because of practical reasons, but the dissolution will increase with temperature [26].

SINTEF was satisfied with the result, and they encourage service companies to bring the result to the market. Some potential operational benefits and shortcoming:

- Casing window could be opened without the use of a rig.
- Cutting and pulling casing would not be necessary to open the casing window.
- Operation could be done offline and in many wells simultaneously.
- Process is environmentally friendly compared to current methods.
- Some challenges in terms of handling chemicals and the chromium that has been dissolved.
- Handling very corrosive material (HCL, H₂SO₄).

7.2.2 Interwell

Interwell is a service company established in Norway in 1992. Interwell has grown in size over the years and made a name as a provider of plugs, packers and straddles. They have in recent years come up with a method for permanent P&A. They have created a heat generating mixture, with thermite which can burn at temperature up to 3000 °C. The mixture is placed in the well at desired depth. When the thermite burns it melts away the surrounding casing, cement and formation. When temperature drops the melted casing and formation creates a barrier against the reservoir. The created barrier will have properties similar to the cap rock [27].

Interwell has 4 years of experience and conducted over two hundred test on various scale. In 2016 they conducted a field test in two onshore wells in Canada, named Whitehorse and Benjamin. There was placed two plugs inside the Whitehorse well, it had a failed pressure test. The third plug inside Benjamin holds a 77 bar differential pressure. Both wells are put under long term monitoring. The test so fare is looking promising, Interwell learnt a lot from this field test. Centrica won Oil & Gas UK 2016 Award in the category “Business Innovation and Efficiency (large Enterprise)” for this field, where they used the concept from Interwell [28].

7.2.4 Downhole tubing disposal

Oilfield innovations are working on a method for leaving the tubing in hole. Pulling the tubing out of the hole is a heavy operation, and require a drilling rig. There is a HSE risk involved with lifting heavy objects.

The method is based on compaction of the tubing. A circular object is in general very resistant to compaction (vertically), but if it is cut vertically it loses its structural strength. A test done in a lab in the US, managed to get 54 % compaction in a horizontal pipe, which is the hardest cases since there are no help from the gravity force [29].

The Method:

1. The tubing is cut vertically into spaghetti like strands.
2. Then detach the shredded portion from the top of the tubing.
3. A piston is placed on top of the shredded portion, and hydraulic pressure is used to compact the tubing.
4. Open section is logged with thru tubing to verify good cement behind casing.
5. Then cement thru tubing in the window created by the compaction.

This method meets the requirements given in NORSOK D-010 rev. 4. The testes so far has been promising, and opens up for more wells to be P&A'd from vessel rather than rigs. The rental on LWIV is much lower than on rigs. Realizing this method can reduce cost and increase safety of the P&A operation, since the tubing can be left in hole.

7.3 Formation as a barrier

The use of creeping formations as a barrier is a hot topic in the oil and gas industry. Statoil presented during their speak at SINTEFs P&A conference that they have saved 6700 mill NOK over the last 3 years by using formation as a barrier [30]. They have found formation as a barrier from the southern North Sea up to the northern part of the Norwegian Sea.

It can potentially save a lot of time on the P&A operation at the Brage field, as shown in this thesis. Many of the wells on the NCS has poor cement jobs, and there needs to be established a barrier between the casing and the formation. In order to secure a seal across the entire cross section of the well. If the cement outside the casing is absent there might be need for milling operation, squeeze cement job or perforate wash and cement technology. Operations like that is not necessary if it can be proven that the barrier is already in place, in form of a creeping formation.

Creeping shale is known to cause problem during drilling, and can cause a tight hole. Statoil ran a bond log at the Oseberg field and discovered bonding in an interval without cement behind the casing. The log showed that creeping shale was able to seal around the casing and create a good bond with the casing in the same way as cement.

In terms of Mineralogy, what is needed in order for the shale to serve as a creeping formation? [30]:

- Total Clay content must be larger than 40%.
- Quartz content must be less than 25 %.
- Carbonate content possibly less than 5%.
- Clay mineral distribution implies that a high percentage of the Smectite is necessary part of a creeping shale formation.

Statoil is the leading operator on the NCS. They have logged several wells on NCS to gain more knowledge about creeping formations. It usually takes 2 to 14 days before good quality barriers is observed after setting the casing. In the shallow part in the overburden at the Troll field, there were not registered any bonding in the interval with the Hordaland green clay and the casing after 14 years. The reason might be a combination of lower pore pressure, lower stresses and lower temperature which all could contribute to lack of creep properties. On the other hand the deeper part of the Hordaland Green Clay always has good bonding to the cement [31].

The general procedure for formation as a barrier:

- Define the interval up to where the shale is still larger than the reservoir pressure the formation can be exposed to.
- Log the formation with CBL/USIT and evaluate.
- Pressure test every new formation in a geological field.
- For later usage you need only to log to verify bonding.

In the SINTEF P&A conference Aker BP [32] held a presentation about how to activate natural barriers. The general procedure above describes how to define shale formation. As described above the creeping formation in the shallow parts of the field does not always create a good bond with the casing. Aker are doing tests on how to activate the shale barrier in an engineered operation. The best result so far is gained from rapid pressure drop in the annulus. Increase of temperature may also be a good method in many cases, but needs more work to understand limitations with the method. It is also possible to combine these methods with a heater and a pump. The idea behind this method is to create similar conditions as the one further down in the well. Result from Troll always showed good bonding to the casing deep in the well but not in the shallower part of the green clay.

7.4 Guidelines

Creeping formations has been implemented in the latest revision of NORSOK. The NORSOK standard is based on cement and has the same requirements in terms of contact length and verification. Even though they have very different properties, as shown in Table 5 below.

	Cement	Shale
Acidic environment (CO ₂ /H ₂ S)	Breaks down	No reaction
High temperature	Degrades	No reaction
Ductility/Plasticity	Brittle	More plastic
Permeability	0,02 mD	0,000001 mD

Table 5- Physical properties for cement and shale [31]

Acona used the difference in physical properties in table 5 above as an argument for saying that 10 m of creeping shale is sufficient as a barrier element, and that NORSOK should differentiate between cement as an annular barrier and shale as an annular barrier [33]. They made an argument for that length was irrelevant since shale has several order of magnitude lower permeability than cement.

NORSOK states that for a creeping formation to be a part of a permanent barrier it has to be verified by logging, and if the log is not continues it has to be pressure tested. Acona suggest that a pressure test would be sufficient way to verify the formation strength of a creeping formation.

In NORSOK chapter 9.6.2: "Permanently abandoned wells shall be plugged with an eternal perspective" [4]. The word eternal is very hard to relate to, and it is very confusing and has no practical meaning. The word eternal is totally absent in the UK guidelines. It is not possible for a barrier to last forever, nature will eventually break it down [34].

Eternal cannot be used as an input value in models. Therefore, many companies operate with 600-700 years as a best practice. Another industry that has to deal with long time storage of hazardous material is the nuclear industry. Nagra is a company that deals with nuclear storage waste and they operate with 100 000 years for low/intermediate level waste and 1 000 000 years for High level waste [35]. It is probably no difference, dealing with an eternal perspective rather than 1 000 000 years.

NORSOK is always being challenged, to lower the cost without compromising on well integrity and safety. In some wells there might not be the required length of formation bonding with the casing. If it is proven that 10 m of bonded formation will provide sufficient well integrity. It will increase the number of wells that can be P&A with formation as an annular barrier.

8 Conclusion

The decision to decommission a field is first and foremost based on economics. The production rate on Brage is declining, and the field is expected to be in production until 2030. It is recommended to start the planning for the decommissioning a long time ahead of the P&A operation starts, in order to save time and money. The objective of this thesis was given by Wintershall; plan the P&A operation for the different wells at Brage, by setting a dual barrier plug against the Hordaland green clay. Thereby categorizing the different wells by the operation necessary to safely P&A the different categorise, in accordance with applicable regulations, which in the case of P&A in Norway is NORSOK D-010.

There were made a sketch of each well as-is and after decommissioning, as a way of getting a visual impression of the necessary operations required to permanently P&A the well. The wells were then put into categorise, based on the different casing design. There were especially three categorise that stood out: pre-drilled wells, simplified casing design and the most dominant group were wells with a production liner and 10 3/4" tie-back casing. A uniform distribution was made for each category, the P50 value for P&A is shown in Figure 66 below.

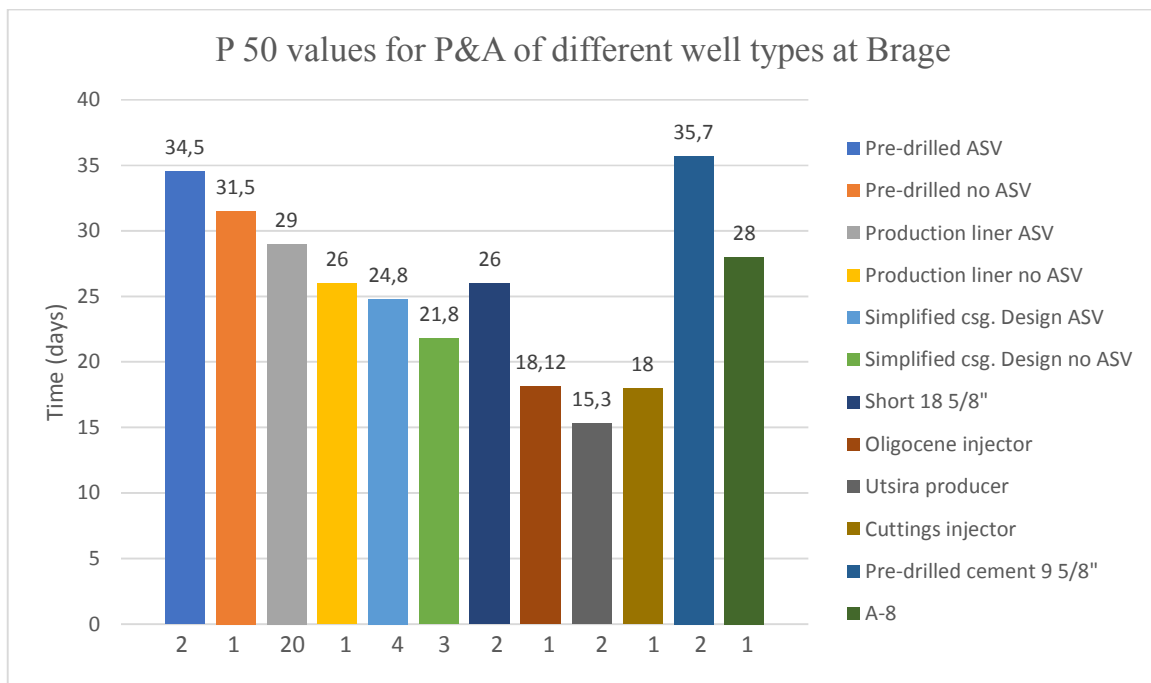


Figure 66- Overview of P50 values for P&A of the different wells at Brage with the number of wells in each category given below each column

By adding the operational times from the different wells, an estimation for decommissioning of the entire field was made. The estimate made in this thesis predict that the P&A operation for the 40 wells at Brage will most likely take 1090 days, almost three years. The estimate does not take into account the effect of learning or the risk of any down time.

The first six wells at Brage was drilled before the platform was in place and tied back to the platform with an internal conductor. Therefore, it is a need to change the conductor, before pulling the casings. These wells are the most time consuming to decommission.

Wells with simplified casing design, has a dummy 18 5/8" casing which does not reach sea bottom. Therefore, it is no need to pull any casing before installing the dual barrier plug. As a result these wells require significantly less time to decommission.

The biggest group of wells are designed with a production liner and 10 3/4" tie back casing. The effect of learning can significantly reduce the total since 50 % of the wells a Brage has this casing design.

For three wells it will not be time effective to place the plug against the creeping clay formation, because of the risk of stuck 9 5/8" casing. Therefore, the cement plug is placed below the 13 3/8" casing shoe. Two of the pre-drilled wells required this procedure, and ended up being the most time consuming.

There are currently a lot of new technology under development, and if the new technology enables the operator to leave the tubing in hole or avoid milling, the P&A operation will become a lot safer and lower the cost.

The use of creeping formation has saved a lot of money on the NCS. It is smart to use the barrier that is already in place, when planning for decommissioning. A lot of research is done to get more knowledge about creeping formations. The researchers at SINTEF believes that shale clay can be used to a larger extent, but it requires more knowledge about key minerals and bonding with the casing.

New technology and the use of formation as a barrier has the potential to save the operators and Norwegian tax payers for huge amounts of money. This will most likely drive the probability curve to the left and lower the time spent on P&A in the future. Since cost is determined by the rig rate and number of days in operation, saving one day will save millions of NOK.

9 Recommendation for future work

For every question answered, a new question came along. Here are some of topics that should be investigated before starting on the P&A process:

Rig or LWIV- Investigate whether using a modern rig and light vessel will be cost saving. The day rate will be higher by using a modern rig, but seeing the speed of the modern rigs it may be done faster.

Time estimation of other technology- Perform a time estimation similar to the one done in this thesis, but for new technology. Comparing the time it to new technology on the market.

Learning effect- Investigate how the learning effect will reduce the operation time for P&A at Brage. Especially for wells with a production liner, it would be interesting to see the difference between well number 1 and well number 20. The crew will learn from one well to another and that will make the operation run a lot smoother and safer.

Rig removal- the time estimate done in this thesis does not include removing of the rig itself. Is it beneficial to pull the legs together with conductors?

Depth investigation of every wells- There will be individual differences from one well to another. Factors like well integrity, cement height, Cement/formation bonding with casing, minimum setting depth.

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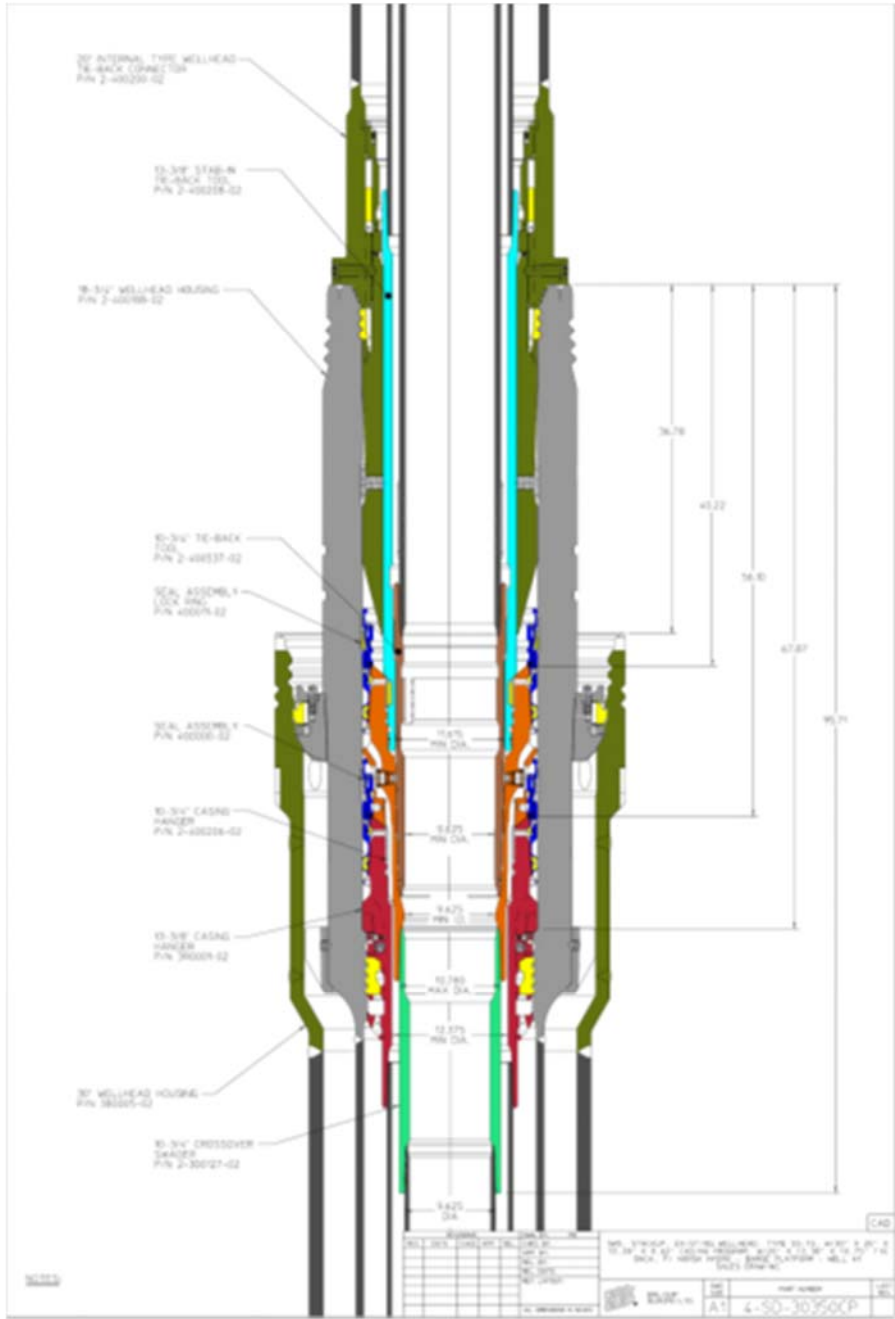
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Appendix A

Cross sectional schematic of the internal conductor on pre-drilled well [7]



Cross sectional schematic of the external conductor on pre-drilled well A-1 [7]

