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Abstract

On the NCS today, there are 1033 subsea wells that are classified with the status online/operational, Drilling, Predrilled, Suspended and Closed[1] and these subsea wells will have to be permanently plugged and abandoned (PP&A) at some point. When the revenue of these subsea wells decreases and the cost is the driving factor, we are left with two options; permanently plug the reservoir section and reuse the slot by drilling a sidetrack or PP&A the subsea well.

P&A operations is associated with high cost for the operating companies, licensees and the Norwegian taxpayers. To maintain the production on the NCS, one have to drill new wells to ensure new discoveries. However, as new wells are drilled others have to be PP&A. By using a riserless light well intervention (RLWI) vessel to conduct P&A operations, one can exclude the use of expensive mobile offshore drilling units (MODUs) and consequently maintain the drilling activity on the NCS.

The current practice is to use a semi-submersible rig with marine riser to perform the reservoir – and intermediate abandonment. By utilizing the current practice and convert it to the new concept of conducting PP&A from a RLWI vessel, we could find the technology gap and the best suited subsea well candidates. The intention is to perform full riserless P&A operations using wireline, coiled tubing and main winch (i.e. a rig-less approach) combined with additional equipment. A large proportion of the current and future subsea wells on the NCS and in the rest of the world will be potential candidates for riserless PP&A with a RLWI vessel. Riserless P&A operations of subsea wells with low well abandonment complexity will most likely reduce the overall P&A expenditures because RLWI vessels has a lower day rate and an effective method of performing the P&A operation.

The objective of this thesis is to identify the RLWI vessel's potential to perform full riserless P&A operations and present its operational boundaries with respect to well abandonment complexity. A description of available and required technology is also given. Three individual base cases with increasing complexity containing operational sequences and well barrier schematics will be presented to show application of existing and required technology and to identify the main challenges.

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Abbreviations

AHC	Active Heave Compensator
AoC	Acknowledgement of Compliance
BOP	Blow Out Preventer
CAT	Cement Adaptor Tool
CBL	Cement Bond Log
CT	Coiled Tubing
CTD	Coiled Tubing Drilling
CTH	Coiled Tubing Head
DHSV	Downhole Safety Valve
EAC	Element Acceptance Criteria
EQD	Emergency Quick Disconnect
FIT	Formation Integrity Test
HC	Hydrocarbon
HXT	Horizontal X-mas Tree
ICP	Internal Cement Plug
ID	Inner Diameter
LA	Land Well
LFL	Lower Flammability Limit
LLP	Lower Lubricator Package
LOT	Leak-Off Test
LS	Lubricator Section
LUB	Lubricator
LWI	Light Well Intervention
MD	Measured Depth
MODU	Mobile Offshore Drilling Unit
MPD	Manage Pressure Drilling
NCS	Norwegian Continental Shelf
OD	Outer Diameter
P&A	Plug and Abandonment
PCH	Pressure Control Head
PGB	Permanent Guide Base
PL	Platform Well
PP	Permanently plugged
PP&A	Permanently plugged and abandoned
PSA	Petroleum Safety Authority

RLCT	Riserless Coiled Tubing
RLWI	Riserless Light Well Intervention
ROV	Remotely Operated Underwater Vehicle
RT	Running Tool
SC	Safety Case
SM	Section Milling
SS	Subsea Well
SSD	Subsea Shut-Off Device
SSI	Subsea Injector
SSR	Seal/Shear Ram
SWAT	Supended Well Abandonment Tool
SWL	Safe Working Load
TA	Temporary abandonment
TCP	Tubing-Conveyed Perforating
TGB	Temporary Guide Base
TH	Tubing Hanger
THERT	Tubing Hanger Emergency Retrieval Tool
THROT	Tubing Hanger Running and Orientation Tool
THRT	Tubing Hanger Running Tool
TOC	Top of Cement
TVD	True Vertical Depth
ULP	Upper Lubricator Package
USSR	Upper Seal/Shear Ram
VXT	Vetrical X-mas Tree
WASP	Well Abandonment Straddle Packer
WB	Well Barrier
WBE	Well Barrier Element
WBS	Well Barrier Schematic
WCP	Well Control Package
WCS	Well Control System
WH	Wellhead
WL	Wireline
WOR	Work Over Riser
XLOT	Extended Leak-Off Test
XT	X-mas Tree

1 Introduction

1.1 History of subsea wells

The Norwegian Continental Shelf (NCS) accommodates some of the greatest and most technological subsea fields in the world. The first subsea well on the NCS was brought into production at the Frigg field in 1982. This was the first step of subsea field development where the focus was to move the production down to the seabed. It was not before the early 90's that subsea wells were considered a realistic option by the operating companies[2]. Rather than building new platforms, subsea wells were built to increase the production using existing platforms to tie in new wells.

Plug and abandonment is an activity that has been ongoing since the early beginning of exploration and development of oil and gas on the NCS. The majority of exploration wells are permanently plugged and abandoned (PP&A) immediately after all essential information is gathered.

Currently there is a great number of development wells that are permanently plugged (PP), but not abandoned at fixed facilities on the NCS. Subsea well are relatively new and it is predicted that the "plug wave" of subsea wells will start in 2020. Currently, the oldest subsea wells to be PP&A on the NCS are the water injection wells at Snorre and Draugen, both drilled and completed in 1993[1].Even though the subsea wells are relatively young compared to platform wells, the majority of the subsea wells were not designed with respect to its life cycle, i.e. P&A. The result of this is greater challenges when P&A operations commences. Good quality cement, external cement at internal plug setting depth, length of external cement satisfies the minimum requirements and casing selections were not always thoroughly considered during well design and operation.

The cost of PP&A of subsea wells are higher than platform wells and one of the reason is that mobile offshore drilling unit is allocated to conduct the P&A operation. Riserless light well intervention vessels are currently used during some P&A operations and because of that, the total P&A cost has been reduced as a consequence of its lower daily rig rate.

1.2 Objective

This thesis will study the current and upcoming applications and limitations of a riserless light well intervention (RLWI) vessel to conduct all phases of a riserless plug and abandonment operation of subsea wells. The purpose of this thesis are:

1. *Perform a study of plug and abandonment requirement, technology and operations*
2. *Evaluate conventional and upcoming technologies and methods to perform PP&A*
3. *Construct well scenarios with varying complexity to demonstrate changes in operation plans combined with the existing and new technology for RLWI vessel.*
4. *Perform an analysis to reveal the boundary of well abandonment complexity of subsea wells to be PP&A by a RLWI vessel.*
5. *Discuss the RLWI vessel's operational boundaries and potential to conduct riserless P&A operations.*

1.3 Structure of Thesis

This thesis is divided into 15 main chapters and consists of sub chapters. The main chapters are:

- *Chapter 1 is an introduction to the subsea well history and plug and abandonment on the Norwegian Continental Shelf.*
- *Chapter 2 gives a description of the regulations and standards for P&A, the well barrier philosophy, and the well abandonment complexity defined by Oil & Gas UK.*
- *Chapter 3 describes the main differences between subsea and platform P&A, and it describes and illustrates the differences between vertical – and horizontal x-mas trees.*
- *Chapter 4 gives an introduction to monohull vessels, technical specifications to the monohull/RLWI vessel applied in this thesis, current subsea well intervention equipment and additional subsea equipment to assist during a P&A operation.*

- *Chapter 5 describes the standard coiled tubing equipment and applications prior to introduce the riserless coiled tubing system. This chapter shall provide information regarding topside – and subsea equipment and the operational sequence of installing this riserless system.*
- *Chapter 6 describes and illustrates with well barrier schematics a typical P&A operation on the NCS.*
- *Chapter 7 introduces different plugging materials that can be applied during a P&A operation*
- *Chapter 8 describes different approaches to establish permanent well barriers during a P&A operation*
- *Chapter 9 describes some of the main challenges of riserless P&A using a RLWI vessel. It also includes existing and proposed equipment used during some of the well abandonment phases.*
- *Chapter 10 is a short overview of the proposed well control rig ups.*
- *Chapter 11 describes three base cases with increasing complexity with a proposed approximation to the P&A operation. Each base case includes a table of the operational sequences and well barrier schematics to illustrate the operation.*
- *Chapter 12 consists of the discussion part.*
- *Chapter 13 is the conclusion.*
- *Chapter 14 consists of the appendices.*
- *Chapter 15 is the references.*

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2 Rules and Regulations on the Norwegian Continental Shelf

This chapter gives an overview of the requirements and guidelines that applies for any given plug and abandonment (P&A) operation. The Petroleum Safety Authority (PSA) is the regulatory authority for technical and operational safety and supervises all petroleum activities on the NCS. All requirements and guidelines complies with the Norwegian regulations, i.e. Petroleum Act, and are formed by industry experts and previous experience within the petroleum industry to ensure adequate health, safety, environment and quality (HSE&Q) during operations. There are different regulations within the oil and gas industry. However, which one to apply depends on the geographical location of operation. The NORSOK standard applies for all actors conducting operations on the Norwegian Continental Shelf (NCS).

The regulatory hierarchy on the NCS[3];

- *Regulations*
- *Guidelines (to the regulations)*
- *National and international standards that are referenced in the guidelines, such as NORSOK standards, ISO standards, API standards and IEC standards.*

All well operations commenced on the NCS are obliged to fulfill the rules and regulations. These inexplicit rules and regulations have been compiled into guidelines and standards. The NORSOK standard is created by an industry initiative to give the user an understanding of how to add value, reduce cost and lead time and eliminate unnecessary activities in offshore field developments and operations[4].

There are several NORSOK standards for petroleum activities and it provides a set of minimum requirements for the equipment and/or solutions to be used in a well. Its purpose is to replace any oil company specifications and other industry guidelines and documents for use in existing and future petroleum activity[4].

2.1 Regulations and Standards for P&A on NCS

The facilities regulations chapter 8, section 48, cover the well barrier requirements. Here it is stated; *"When a well is temporarily or permanently abandoned, the barriers shall be designed* *such that they take into account well integrity for the longest period of time the well is expected to be abandoned”*[5]. When inspecting the guidelines, one see that in order to fulfill the requirements, the NORSOK D-010 standard has to be followed.

NORSOK D-010 is a functional standard with prescriptive requirements and covers *“Well Integrity in drilling and well operations”*[4]. Chapter 4 and 9 in NORSOK D-010 standard provides the minimum requirements for P&A operations. Its Intention is to let operating companies freely choose a solution that meets the given requirements. Even though the operating companies have full responsibility for being compliant with the standard, it has an indirect encouragement to develop new methods and technology[3].

It is of great importance to understand the term “shall” and “should”. The term “shall” denotes the minimum requirements that are strictly to be followed and no deviations are permitted. The only exception is when accepted by all the involved parties[4]. The term “should” denotes a recommendation and does not exclude other possibilities.

2.1.1 Well Integrity

“Permanently abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical and geological processes”[4]

To understand all aspects of P&A operations, it is fundamental to clarify the importance of well integrity. Well integrity is defined as the “application of technical, operational and organizational solutions to reduce the risk of uncontrolled release of formation fluids throughout the life cycle of a well”[4]. Well integrity must be understood and respected from the initial well design and to the end, where the well is permanently plugged and abandoned (PP&A). All well activities shall be carried out in a safe and prudent manner during the wells life cycle. Well integrity comprises the technical, operational and organizational solutions to reduce any risks that can occur throughout the life cycle of the well[4].

To ensure a safe P&A operation, one has to choose the best operational and technical solution for that specific well. To find the best solution one has to consider several factors, e.g. fatigue, corrosion, material specification of the equipment, well design, existing casings, cement, pressures, ++. The NORSOK D-010 standard focuses on establishing technical well barriers by use of well barrier elements (WBEs), their acceptance criteria, their use and monitoring of integrity during their life cycle [4].

2.1.1.1 Well Barrier Elements

NORSOK D-010 defines a well barrier element (WBE) as *"a physical element which itself does not prevent flow but in combination with other WBE's forms a well barrier"*[4]. Each WBE's is genuinely important and especially when installing cement plugs during P&A operations as there is currently no field proven technology that allows monitoring WBE's after final permanent abandonment. However, fiber optics may allow the operator to monitor the well integrity of a permanently WB in the future[6].

Cement, casing and formation are typical WBE's that are interlinked to form a well barrier when conducting a PP&A operation. Keep in mind that during the P&A operation there are several other WBE's involved.

2.1.1.1.1 Well Barrier Element Acceptance Criteria (EAC)

During a P&A operation there are some requirement regarding the WBE's. Table 1 describes the additional EAC requirements than what is described in NORSOK D-010, section 15.

Table 25 – Additional EAC requirements

Table no.	Element name	Additional features, requirements and guidelines
2	Casing	Steel tubulars WBE shall be supported by cement or alternative plugging materials.
22	Casing cement	Cement in the liner lap or in tubing annulus can be accepted as a permanent WBE when the liner is centralized in the overlap section. The casing cement in the liner lap shall be logged.
51	In-situ formation	The in-situ formation (e.g. shale, salt) shall be impermeable and have sufficient formation integrity.

Table 1: Additional EAC requirements [4]

2.1.1.2 Well Barriers

According to NORSOK D-010 a well barrier is an *"envelope of one or several well barrier elements preventing fluids from flowing unintentionally from the formation into the wellbore,* *into another formation or to the external environment"*[4]. Before P&A operations commences, one shall identify each set of WBE's and document its technical requirement. It is important to identify and understand the function of the well barrier elements used in well. There might be several well barrier elements in place, but they will only serve as a containing well barrier when they are interlinked into what we refer to as a barrier envelope[7].

As mentioned in section 2.1.1, all wells shall be permanently abandoned for eternity.

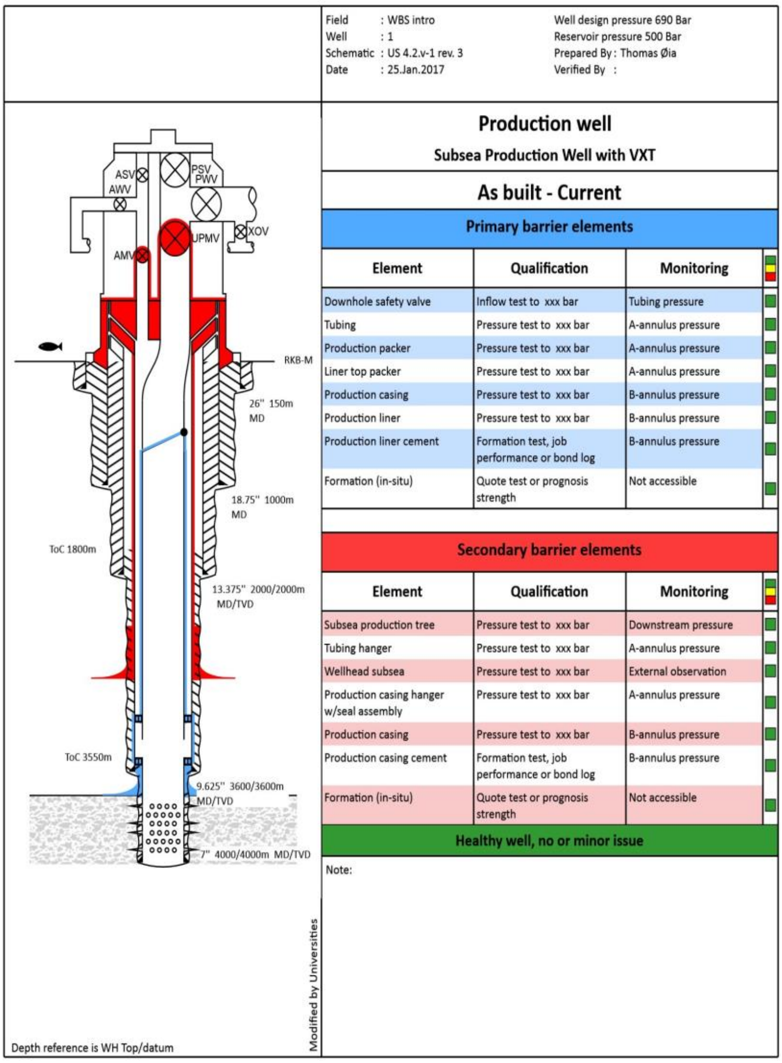
2.1.1.3 Well Barrier Schematics (WBS)

Thoroughly planned operations has a detailed description of the operational sequences. It is a requirement that each well activity and operation contains a WBS[4]. The WBS is developed as an illustration to display the presence of the different well barrier envelope. The WBS in Figure 1 is an example of a production well that is shut-in. When designing a WBS it is important to use the "hat-over-hat" principle, i.e. establish two separate well barrier envelopes. The first "hat" is the primary well barrier and is typically marked with blue. Its main function is to prevent unwanted flow of fluid to reach the surface. The second "hat" is the secondary well barrier and is marked with red. This WB work as a backup to the primary WB in case of failure and shall be designed to withstand any anticipated future well pressures or flow of fluids.

The WBS contains important information about the well. In the WBS example in Figure 1, there is a column of several WBEs listed under primary or secondary WB. Each WBE has a description of the element, qualification method and a monitoring status. The monitoring status is a risk status code marked by color and is then assessed in a risk analysis.

All WBS's provided in this thesis is prepared with the Wellbarrier illustration tool after permitted access by Wellbarrier AS [(1)].

[1] Wellbarrier AS - https://www.wellbarrier.com



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

Secondary barrier elements		
Element	**Qualification**	**Monitoring**
Subsea production tree	Pressure test to xxx bar	Downstream pressure
Tubing hanger	Pressure test to xxx bar	A-annulus pressure
Wellhead subsea	Pressure test to xxx bar	External observation
Production casing hanger w/seal assembly	Pressure test to xxx bar	A-annulus pressure
Production casing	Pressure test to xxx bar	B-annulus pressure
Production casing cement	Formation test, job performance or bond log	B-annulus pressure
Formation (in-situ)	Quote test or prognosis strength	Not accessible

Figure 1: Subsea Production Well with VXT showing primary and secondary barrier

2.2 General requirements for P&A operations

An operator and its licensees typically agrees to PP&A a well or a wellbore because of insufficient hydrocarbon (HC) potential to complete the well or due to reservoir depletion and/or lack of production and revenue. Sometime one decides to temporary abandon the well with an expectation of getting new technology or solutions to increase the oil recovery and revenue. The requirements are almost the same regardless of doing permanent or temporary abandonment. The major difference is the choice of WBEs where one account for abandonment time, ability to re-enter the well or if one are supposed to resume operations after temporary abandonment (TA)[4].

2.2.1 Temporary Abandonment (TA)

When a P&A operation on a subsea well commences, one typically deal with a well that has been TA for a duration of time. There are different requirements for TA and it depends whether it is monitored or not and if it is a subsea or platform well. When the primary and secondary barrier is continuously monitored and routinely tested, it is defined as a “TA well with monitoring” and there is no maximum abandonment period. If these criteria cannot be fulfilled, the well shall be categorized as a “TA well without monitoring” and the maximum abandonment period shall be three years.

It is important to keep in mind that a TA subsea well without monitoring shall have an inspection program and have a program for visual observation at least once a year. These wells are associated with a higher risk due to the unknown pressure when removing the well control equipment.

The upcoming sections will describe the requirements and acceptance criteria for well barriers when establishing permanent well barriers with an eternal perspective. The overall goal of PP&A is to re-establish a well barrier, e.g. cap rock, above any permeable formations/reservoirs/sources of inflow to avoid leakages to surface or other permeable formations.

2.2.2 Permanent well barrier

A permanent well barrier, from now referred to as permanent WB, shall be installed such that it extend across the full cross section of the wellbore, include all annuli and seal both vertically and horizontally. All well barriers shall be placed adjacent to an impermeable formation with sufficient formation integrity for the maximum anticipated pressure[4].

According to NORSOK D-010 standard, a permanent WB should have the following characteristics;

a) *Provide long term integrity (eternal perspective)*
b) *Impermeable*
c) *Non-shrinking*
d) *Able to withstand mechanical loads/impact*
e) *Resistant to chemicals/substances*

f) Ensure bonding to steel

g) Not harmful to the steel tubulars integrity

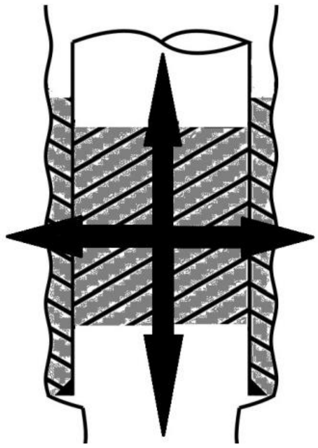


Figure 2: Self-made Well barrier across the full cross section of the well

The industry is provided with several plugging materials, but Portland cement is still thought to be the most applicable due to its low cost and known properties.

Removal of downhole equipment is not required as long as the integrity of the well barriers are achieved. Control cables and lines shall not be a part of the permanent well barrier due to the risks associated with potential leak paths[4].

A P&A operation consists of installing permanent WBs at positions in the well to restore its original integrity. The four types of permanent well barriers used for P&A operations are;

- *Primary well barrier – First barrier that isolate a source of inflow and pressures from reacing the surface/seabed*
- *Secondary well barrier – Back-up to the primary well barrier*
- *Crossflow well barrier – To prevent flow between formations*
- *Open hole to surface well barrier – To permanently isolate flow conduits from exposed formation(s) to surface/seabed*

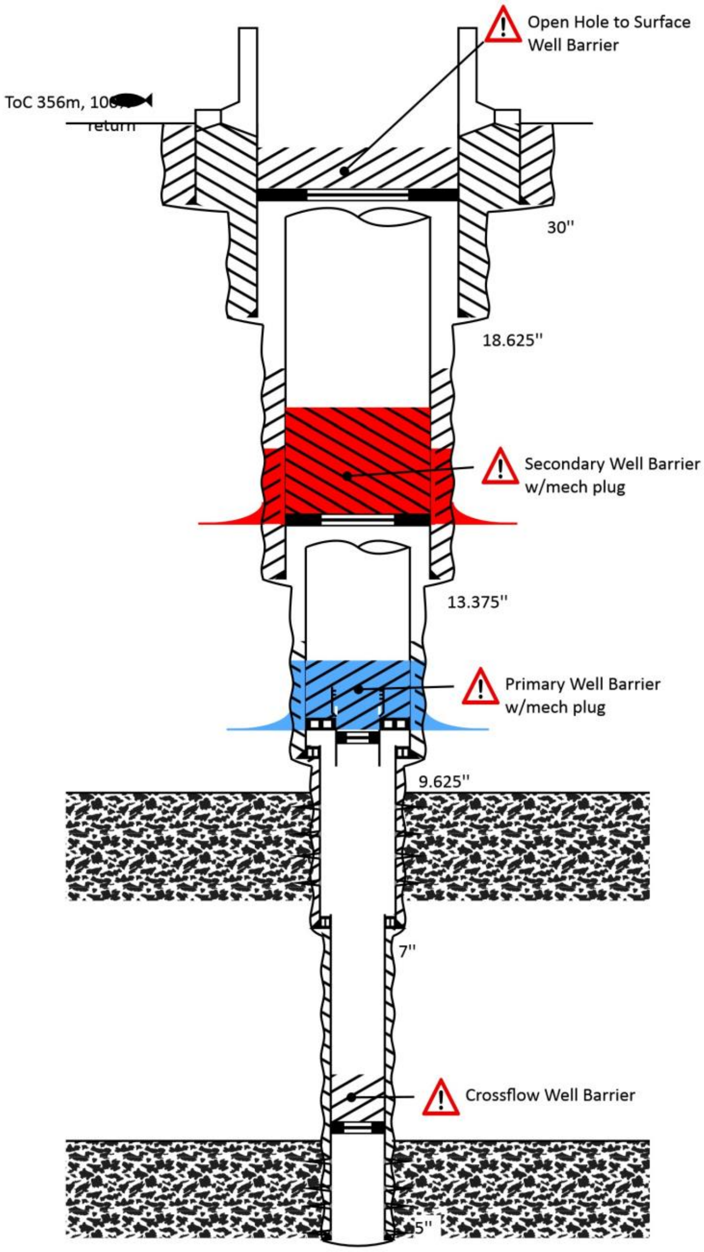


Figure 3: Four types of well barriers

For instance, an external WBE, casing and an internal WBE is placed above the production packer in the 9⅝" production casing and constitutes a complete permanent well barrier. These three WBEs must be combined and seal both vertically and radially in order to fulfill the requirements. In the following section, one can see the requirements for each element given in NORSOK D-010.

2.2.2.1 Permanent WBE acceptance criteria

For a permanent WBE to be accepted it must satisfy certain criteria[4];

- *The minimum cement plug length shall be:*
- *Open hole cement plugs – 100m MD with minimum 50 m MD above any source of inflow/leakage point*
- *Cased hole cement plugs – 50 m MD if set on a mechanical/cement plug as foundation, otherwise 100 m MD.*
- *Open hole to surface plug – 50 m MD if set on a mechanical plug, otherwise 100 m MD.*
- *It shall extend across the full cross section of the well*
- *It shall be positioned at a depth where anticipated pressure does not exceed minimum formation stress*
- *The different plug types shall be verified by either logging, tagging, pressure test or a combination of these verification methods.*

This is a compilation of the overall criterions given in NORSOK D-010 and gives a general overview of a permanent WBE acceptance criteria. See Appendix 1 for more specifications.

The illustration below are given to exemplify some P&A scenarios to get a better understanding of the requirements in terms of plug lengths and verification methods.

There are many different ways to perform a P&A operation and it all depends upon several factors, e.g. completion, permeable zones, corrosion, status of cement behind casing, etc.

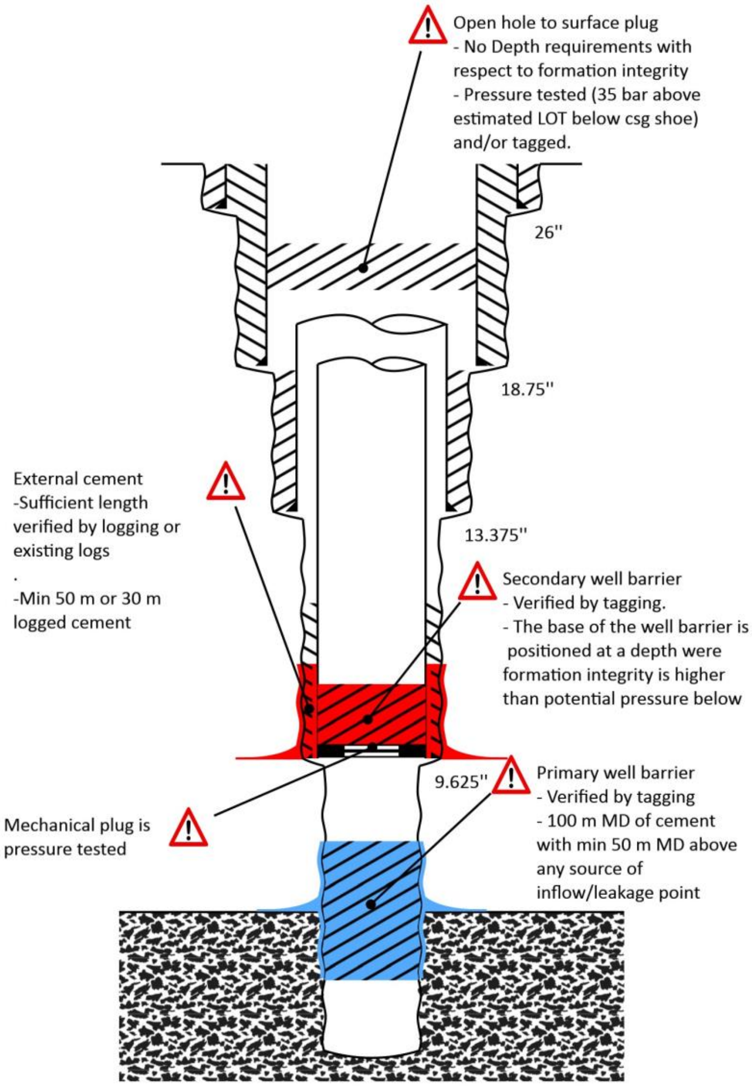


Figure 4: Permanent abandonment, open hole and inside casing plugs

2.2.2.2 Positioning of well barrier

The positioning of a well barrier (WB) is crucial in order to ensure formation integrity at the base of the WB. The anticipated pressure at the base of a WB shall not exceed the formation fracture pressure in order to ensure sufficient formation integrity. The setting depth of all permanent plugs is a function of the fracture gradient in that specific well and it shall be set in an impermeable formation. It is important to clarify that one have to account for the secondary WB, i.e. the secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier[4].

One important parameter in the planning stage of a P&A operation is to analyze the formation strength. The formation fracture pressure is typically obtained from the drilling activity, where a leak off test (LOT), formation integrity test (FIT) or an extended leak off test (XLOT) was conducted when the casing shoe was drilled out. By using the information provided, one can set a WB at a depth where the pressure below the permanent WB does not fracture the formation and thus inducing communication to surface.

By adding one or more of the formation stress tests above into a pore pressure plot, one can determine the plug setting depth. In a P&A phase, the pressure plot is typically presented as depth (m TVD) versus pressure (bar) instead of depth versus specific gravity. By adding an influx pressure curve, which is the influx pressure exerted by the source of inflow, typically assume gas as the influx source, one can find the minimum setting depth at the intersection between the influx pressure curve and the prevailing fracture pressure curve.

Figure 5 shows a typical pore pressure plot where one can find the minimum setting depth for the permanent WBs. In this case, the intersection between the influx pressure curve (yellow) and the fracture pressure curve (green) is found at approximately 2200 m TVD. Hence, the minimum setting depth for the permanent WB (secondary WB) must be set below this depth.

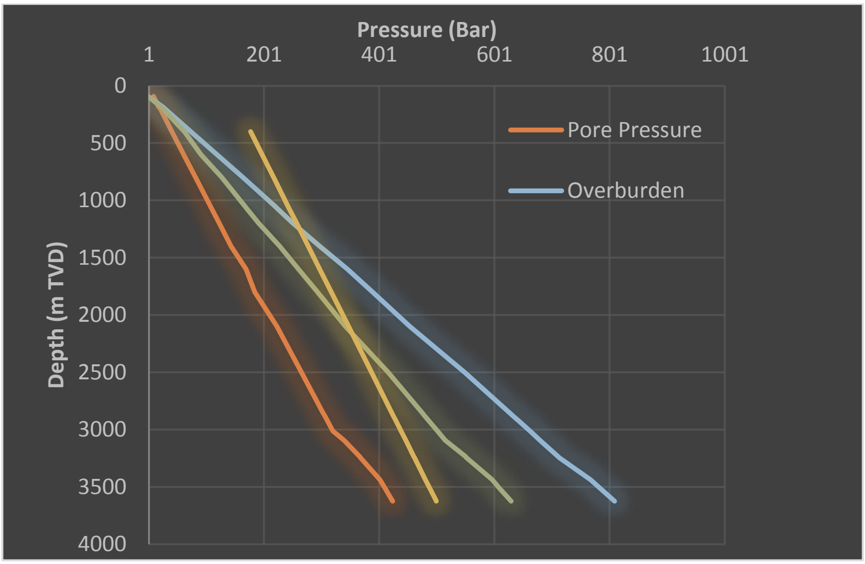


Figure 5: Minimum setting depth - Pressure curves

Note that there are different approaches to which fracture pressure to use and NORSOK D-010 does not define which one to use. Some companies uses the minimum horizontal stress found in a XLOT and this results in a shallower set plug.

2.3 UK oil and gas guidelines

Oil & Gas UK has a guideline, "Guidelines on Well Abandonment Cost Estimation", for P&A operations regarding how to divide P&A work in wells into phases[8]. This guideline is developed as a template of how to separate each wells scope of work based on well abandonment location, phases and complexity/work type. Because of this, each well can be classified with a unique P&A code.

There are three possible physical locations of a well and it is defined as a platform well (PL), subsea well (SS) and land well (LA) [8]. This thesis will only focus on subsea wells (SS), and the two other locations will be not be regarded due to the use of a RLWI vessel.

2.3.1 Operation separated into well abandonment phases

NORSOK D-010 does not differentiate the P&A operation into phases. A phase is a set of operational sequences/work packages and all the phases constitutes a P&A operation. Oil & Gas UK divide the P&A operation into three phases and defines them in their standard "Guidelines on Well Abandonment Cost Estimation". For a more accurate analysis of the P&A operation, it will be dived into four phases in this thesis. In SPE-169203, it is suggested to add a fourth phase, preparation of phase 1. The reason for this is that RLWI vessels can be applied when performing the preparatory work of phase 1 regardless of the abandonment complexity of the upcoming phases[9]. This preparation phase is from now on referred to as phase 0.

2.3.1.1 Phase 0 – preparatory work

This is the initial phase of preparatory work where the well is killed, tubing is punched and/or cut, heavy fluid is circulated down tubing and up annulus and deep– and shallow set plug are installed[9]. One could also retrieve the x-mas tree in this phase, but this is currently only practiced for subsea wells with vertical x-mas trees.

2.3.1.2 Phase 1 – Reservoir abandonment

This phase consists of fully isolating the reservoir from the wellbore and is done by installing a primary and secondary permanent barrier to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved[8].

2.3.1.3 Phase 2 – Intermediate abandonment

This phase consists of isolating liners, milling and retrieving casing, and setting barriers to intermediate hydrocarbon or water-bearing permeable zones and potentially installing near-surface cement. The tubing may be partly retrieved, if not done in Phase 1. Complete when no further plugging is required[8].

2.3.1.4 Phase 3 – Wellhead and conductor removal

This is the last part of a P&A operation and consists of retrieving the wellhead, conductor, and shallow cuts of casing string. Complete when no further operations required on the well[8].

2.3.2 Well abandonment complexity

Each of the previously defined phases has different complexity in terms of abandonment work and it is categorized into digits from 0 to 4 to reflect the complexity. The type of work is defined in "Guidelines on Well Abandonment Cost Estimation" as[8];

Type 0: ***No work required*** *– A phase or phases of abandonment work may already have been completed*

Type 1: ***Simple Rig-less Abandonment*** *– Using wireline, pumping crane, jacks and RLWI vessel*.

Type 2: ***Complex Rig-less Abandonment*** *– Using CT, HWU, wireline, pumping, crane, jacks. Subsea completed wells will use Heavy Duty Well Intervention vessel with riser.*

Type 3: ***Simple Rig-based Abandonment*** *– Requiring retrieval of tubing and casing*

Type 4: ***Complex Rig-based Abandonment*** *– May have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs.*

To enable all P&A operations to be conducted by a RLWI vessel, one have to have to find appropriate methods and solutions to avoid type 3 and 4 P&A operations that normally would require a semi-sub for a subsea well. This categorization method is applied in the upcoming base cases in chapter 11.

Information regarding the well complexity and abandonment phases can be applied in a matrix. It can provide the user with a table to record the abandonment complexity for the four phases for a subsea well or wells. Table 2 is an extended version of the given table in the Oil & Gas UK guideline and is more applicable for the upcoming analyses.

The table also provides an example of a subsea well that is shut-in and where preparatory work (phase 0) is completed. Hence, it is ready to be PP&A. The well is to be abandoned above the reservoir (phase 1) after the production tubing has been pulled (due to control cables), then intermediate P&A (phase 2) commences, the last sequence is to remove the wellhead and conductor (phase 3). Phase 2 (open hole to surface barrier) and phase 3 (WH and conductor removal) is in this case type 1 complexity, meaning that a RLWI vessel is used.

Subsea well			Abandonment Complexity				
			Type 0	**Type 1**	**Type 2**	**Type 3**	**Type 4**
			No work required	Simple Rig-less	Complex Rig-less	Simple Rig-based	Complex Rig-based
Phase	**0**	Preparatory Work	x				
	1	Reservoir Abandonment				x	
	2	Intermediate Abandonment		x			
	3	Wellhead and Conductor Removal		x			

Table 2: Abandonment Complexity Type and Abandonment Phase [9]

Based on this subsea well's complexity, it will have the following P&A code: SS 0/3/1/1 → Subsea (SS) Phase 0 = Type 0/Phase 1 = Type 3/Phase 2 = Type 1/Phase 3 = Type 1.

By coding all wells on the NCS, one can compile each phases into larger batches and conduct a thoroughly analysis of time duration and/or cost for larger P&A campaigns. The analysis can also give us a brief overview of the future demand of vessels due to the classification of abandonment complexity. There is also a table for phase 1, 2 and 3 providing the criteria for how to classify the well abandonment complexity based on the well characteristics. See Appendix B.

3 Subsea P&A vs Platform P&A

The greatest difference between a subsea and platform well, is the position of the wellhead (WH) and well control equipment. There are some general differences listed below, which will affect the way we conduct PP&A.

Platform well:

- *Conductor runs from x depth below seabed to surface*
- *WH on surface*
- *Dry XT*
- *Access and pressure control of all annuli*

Subsea well:

- *Top of conductor at seabed*
- *Subsea WH*
- *Wet XT*
- *Access and pressure control of only A-annulus*

When performing PP&A on subsea wells there is obviously a necessity to use a mobile facility to conduct the operation. On platform wells, the P&A operation requires either a functional derrick, jack-up rig w/skidding system, installation of a modular drilling rig or if possible a rig-less abandonment approach (i.e. combined operation with CT and/or WL and possible jacking units).

There are greater challenges related to P&A operations of subsea wells and one major reason is intuitively the environmental impact. Because of subsea completed wells, the P&A challenges become greater and the risk assessment more complex due to the combination of heavy well control equipment, heave compensated equipment, WH fatigue, time-consuming deployments and other factors.

On the NCS there are 1200 subsea wellbores divided on 59 fields and each wellbore has its own design and complexity[1]. This thesis will therefore discuss which wellbores that are potential candidates to be PP&A by using a RLWI vessel. Chapter 6 will describe a typical P&A operation of a subsea well.

3.1.1 Subsea X-mas Trees

It is important to know the difference between the two subsea Christmas trees (XT) used on subsea wells due to the difference in the operational sequence during a P&A operation. Vertical XT (VXT) was the only option before the horizontal XT (HXT) became popular in the early 90’s. The HXT’s were build to reduce the operational cost when the production tubing had to be changed. Nevertheless, statistically the XT’s are more often changed due to wear and fatigue than the production tubing. This led to greater operational costs than originally and VXT’s are more frequently used today[10].

3.1.1.1 Vertical Christmas tree (VXT) vs. Horizontal Christmas Tree (HXT)

The main difference between these two subsea XT’s is the tree valves on the HXT, which are not inline with the riser. All tree valves are positioned on the sides. Hence, there are no valves in the main bore in a HXT. Another difference is the possibility to monitor the pressure below the production tubing hanger (TH) on a HXT, which is not possible on a VXT. There are also differences regarding the installation and retrieving operation.

VXT: Installed after the tubing hanger and tubing is mounted in the wellhead (WH). For a P&A scenario using a RLWI vessel the tree cap is removed. Subsequently a RLWI stack with a XT adaptor and a tree running tool are installed on top of VXT on the 18 ¾ “ reentry hub. Then preparatory work (phase 0) is conducted or one can just install a deep- and shallow set plug. The deep set plug is typically set as close to the reservoir as possible, either in the tailpipe or just above the production packer. The shallow plugs consists of a tubing hanger plug in the annulus bore and in the main bore. This operational sequence is necessary to be able to retrieve the VXT[11].

HXT: The HXT is installed on top of WH mandrel and subsequently the tubing hanger and tubing is installed in the tree body. The tree was designed to allow simple well intervention and tubing recovery. In a P&A operation, the tubing hanger and tubing must be recovered before recovering the HXT[11]. Methods and operational sequences regarding P&A operations with a HXT, will be discussed in the upcoming chapters.

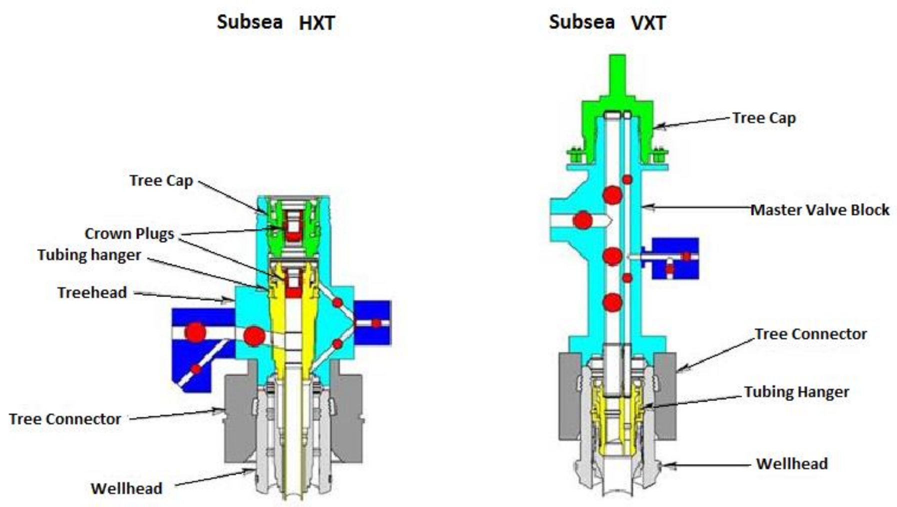


Figure 6: Differences between subsea HXT and VXT configuration [11]

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4 RLWI vessel and Subsea Equipment

4.1 Introduction to RLWI Vessels

The world's first monohull vessel to perform subsea light well intervention was the MSV Seawell in the North Sea (UK sector), operated by Helix Well Ops. The MSV Seawell tested the downhole safety valve (DHSV) and performed a production logging in 1987 at the Magnus field for BP at a water depth of 184m[12]. From this year and forward, the number of subsea well interventions performed riserless increased.

The majority of well interventions on subsea wells on the NCS are conducted by Island Offshore's RLWI vessels. On the UK sector it is the RLWI vessels owned by the Helix ESG and operated by Helix Well Ops that conduct the operation[13].Today's monohull vessels can only perform wireline (WL) (i.e. braided wire, slickline or e-line) interventions on subsea wells, but other intervention jobs will be applicable with the upcoming riserless coiled tubing (RLCT) stack and equipment.

These monohull vessels, referred to as RLWI vessels, are commonly used for well interventions on subsea wells when WL is adequate for the intended intervention job. The conventional well intervention jobs on live subsea wells performed by a RLWI vessel are[14]:

- *Removal of scale (mechanically)*
- *Bailing sand and debris*
- *Removal of Paraffin/wax*
- *Set and retrieve DHSV*
- *Setting/pulling gas lift valves*
- *Opening/closing of sliding sleeves*
- *Fishing operations*
- *Set and retrieve plugs*
- *Perforations*
- *Zone isolation (plug/straddle)*
- *Data gathering (PLT)*
- *Well Clean Up*
- *Fishing on e-line*

- *Temporary P&A operations of subsea wells*
- *Well barrier re-establishment prior to rig work over*
- *Caliper logging*
- *Inspection/repair*
- *Sleeve operations*
- *Chemical spotting*

These vessels are also capable of performing other types of work than entering live subsea wells. They are also used to conduct various subsea operations, e.g. install or retrieve XT's. Island Offshore introduced the concept of riserless coiled tubing drilling (CTD) in 2014, when they drilled out core-samples in the "E39 Rogfast" project[15]. The next year, in 2015, they drilled a pilot hole with RLCT on the Butch field[16]. However, both project were performed without any well control equipment. Coiled tubing (CT) itself is an old technology, but new applications will be provided by applying CT with well control equipment in open water on both live and killed subsea wells from a RLWI vessel. CT has some advantages compared to WL operations and by combining these two intervention methods the scope of work in terms of P&A can increase. CT operations are currently applied during interventions and it has the following applications[17]:

- *Pumping Application :*
  - *Removing sand or fill from a wellbore*
  - *Unloading a well with nitrogen*
  - *Fracturing/acidizing a formation*
  - *Gravel packing*
  - *Cutting tubulars with fluid*
  - *Pumping slurry plugs*
  - *Zone isolation*
  - *Removal of wax, hydrocarbon, or hydrate plugs*
- *Mechanical Applications:*
  - *Setting a plug or packer*
  - *Fishing*
  - *Perforating*
  - *Logging*

- *Scale removal*
- *Cutting tubulars*
- *Sliding sleeve operation*
- *Running a completion*
- *Straddle for zonal isolation*
- *Drilling*

In this thesis, the intention is to perform riserless PP&A of subsea wells from a RLWI vessel, without the need of a workover riser or a riser-tensioning system. Specific stages of the P&A operation are regarded as challenges and have not been conducted on the NCS. Phase 1 and part of phase 2 are yet to be conducted by a RLWI vessel on the NCS. Today, these two phases are considered as a heavy operation and a job for semi-submersible rigs (semi-sub).

Some companies categorizes intervention unit in Category A, B and C, where Cat A is RLWI vessels, Cat B is heavy intervention rigs (semi-sub) and Cat C is drilling and completion rigs (semi-sub)[18]. This categorization will not be applied in this thesis due to the mismatching definition of each category. The reason for that is;

- *A RLWI vessel can take well returns to the vessel and therefore it implies that a RLWI vessel should belong to Cat B.*
- *There have not been built any Cat B units*

This thesis will only differentiate between RLWI vessels and Semi-Subs, with emphasis on RLWI vessels. Before giving specific details of the main subsea equipment for well control during a P&A operation, one should have an overview of the intervention unit used in this thesis.

Other units as category D, I and J are also applicable, but will not be covered nor used in this thesis.

4.2 Use of RLWI vessel for P&A

4.2.1 Current practice

As mentioned, the MSV Seawell was introduced in 1987 to perform well interventions on sub-sea wells. After the first well intervention job, this RLWI vessel started to assist P&A operations on the UK sector by conducting WH removal[13]. The current applications of a RLWI vessel to assist in P&A operations has not evolved too much since its introduction to the petroleum industry, but some progress have been done the last decade. The applications below is listed in an ascending order with respect to its time of introduction.

- *Close/Open DHSV (1987)*
- *WH Removal (1987)*
- *Pull/Run Plugs (1991)*
- *Caliper Run (1992)*
- *Recovery of XT (1993)*
- *Set bridge plug and dump cement (1993)*
- *Set plug in tubing and annulus for temporary abandonment (TA) (1994)*
- *Chemical cutting (1995)*
- *Balanced cement plug and WH removal (part of phase 2 and 3) (1995)*
- *Bullhead reservoir, cementing, XT –and WH removal (1995)*
- *Set bridge plug with tractor and flow well to host platform (2008)*
- *Tubing cutting (2009)*
- *Explosive WH removal (2013)*

An operational sequence of a P&A operation is described in section 6.1 and indicates the present scope of work applicable for a RLWI vessel.

4.3 RLWI Vessels for this case study

There are several suppliers of LWI vessels to conduct interventions on offshore subsea wells. This thesis focuses on operations performed on the NCS and will therefore use Island Offshore's LWI vessel, Island Constructor, as a basis for the upcoming analysis of a vessels application of conducting full P&A operations.

Figure 7: Island Constructor [16]

4.3.1 Technical Specification of LWI vessel Island Constructor

This highly advanced and multifunctional RLWI vessel is equipped with a Dynamic Positioning (DP) system, ensuring the vessel to obtain its geographical position as long as it is within its technical boundaries/limitations (e.g. wave height, sea current, wind, etc.). The vessel is outfitted to perform well intervention services (w/subsea lubricator system), subsea construction- and equipment installation, ROV services, and inspection, maintenance and repair (IMR). For P&A purposes, one need to highlight the vessels main technical specification and characteristics related to the operational sequences and necessary equipment[10]. The vessel does not have integrated equipment for all types of operations, i.e. subsea equipment, CT equipment, pumps, tanks, etc. and this must be facilitated on the cargo deck. Other equipment that might limit the vessels scope of work during a P&A operation is the hoisting capacity, fluid volume return containing HC and accommodation(deck space) of retrieved casing strings and production tubing.

Island Constructor		
Main Characteristics		
Cargo deck area main	1380	m^2
Cargo deck area mezz	320	m^2
Accommodation	90	persons
Tonnage, Capacities		
Technical fresh water	3155	m^3
Liquid mud/Brine, (4 tanks)	500	m^3
Brine, Marpol category B: Chemicals (LFL*), (2+2 tanks)	199	m^3
Hull and Structure		
Moonpool (monohull)	8.0x 8.0	m
ROV launch and recovery system (LARS)	2	off
Topsite		
Module Handling Tower (MHT)		
Lifting height (from hook in upper position to main deck)	29	m
Main hoisting wire and hook; Well intervention mode (single line)	100	t (SWL)
Main hoisting wire and hook; Drilling mode (two falls)	200	t (SWL)
Main Winch		
AHC Winch system (w/Active and passive heave compensation)	100	t (SWL)
Loading/Discharging pumps		
2 off Fresh water cargo pump (@9 bar)	250	m^3/h
Brine pump (@24 bar)	75	m^3/h
Mud pump (@24 bar)	75	m^3/h
Chemical pump (@ 9 bar)	75	m^3/h
Chemical/MEG pump (@ 9 bar)	75	m^3/h
Hydro Carbon Vent System		
Mud gas separator	2360	Sm^3/h
Liquid storage capacity (2 extra tanks can be installed at cost+, 40m^3 extra)	20	m^3
Part of the LFL tank system may also be reconfigured	(199	m^3)

Table 3: Technical Specifications - Island Constructor [19]

Compared to a semi-sub, the RLWI vessel is more prone to the external environment, i.e. weather. The positioning system is designed to keep Island Constructor within the allowable operating limit, which is a unit offset of 3-5% of water depth, taking into account a maximum single failure in the positioning system. The worst case single failure for Island Constructor during dynamic positioning (DP) is losing bow tunnel thruster no. 1[19].

- *Significant wave height:* *Hs=7.0 m*
- *Wave period:* *Ts=13.8 s*

- *Wind speed (10m/10min):* *Vw=21.51 m/s*
- *Current speed (surface):* *Vc=1.03 m/s [2.0 knots]*

Island Constructor will have no limitations maintaining position in above environmental conditions with all thruster in operations. A summary of environmental conditions with all thrusters in operation is shown below:

- *Significant wave height:* *Hs=11.1 m*
- *Wave period:* *Ts=15.6 s*
- *Wind speed (10m/10min):* *Vw=27.5 m/s*
- *Current speed (surface):* *Vc=1.03 m/s [2.0 knots]*

However, operations criteria's from RLWI operations is limited by capacity in the handling system (for lifting), green sea on deck and ROV's and is therefore lower than the DP system capabilities. A set of Well Specific Operational Guidelines (WSOG) is developed to cover for the different type of operations[19].

A vessels motion is described using the six degree of freedom shown in Figure 8 below[20].

The linear motions are described by:

- *Heave: vertical up- and down motion*
- *Sway: lateral side to side (port to starboard) motion*
- *Surge: longitudinal front back (bow to stern) motion*

The rotational motion are described by:

- *Pitch: rotation about Y-axis*
- *Roll: rotation about X-axis*
- *Yaw: rotation about Z-axis*

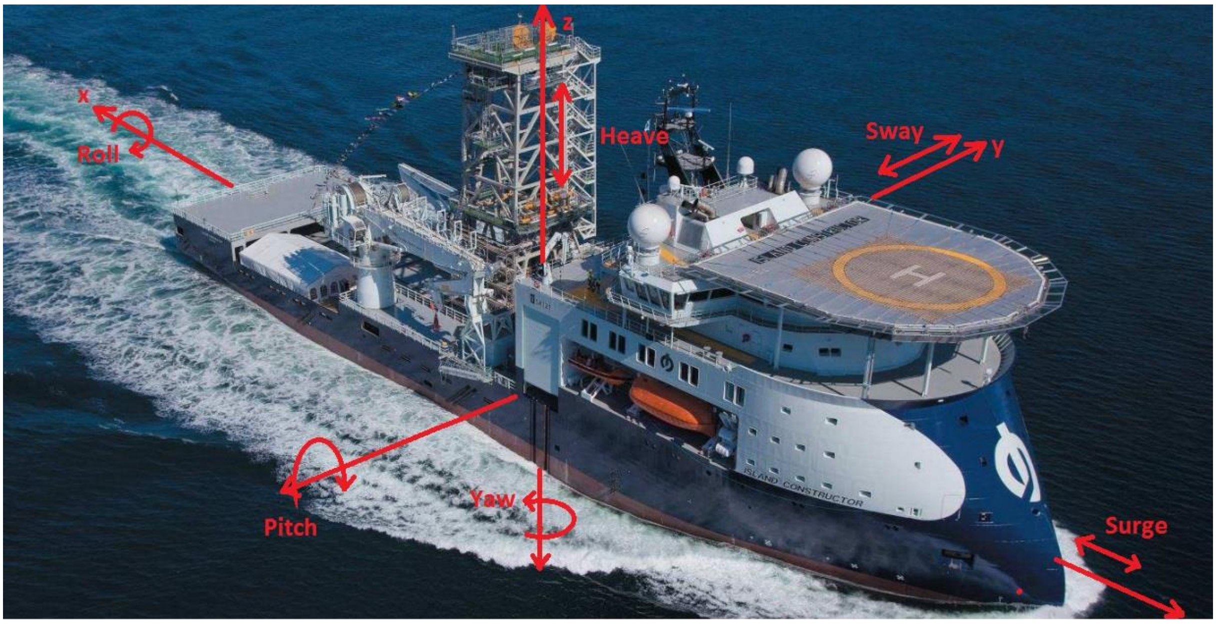

Figure 8: Six degree of freedom on Island Constructor [16]

The combination of these motions can be simulated to calculate the vessels limitations, but that will not be covered in this thesis.

4.3.1.1 Regulatory requirement of RLWI vessel

To be allowed to operate a mobile facility with intention to participate in petroleum operations, one have to possess correct declaration in the country that one intend to operate.

The PSA has the authority to issue a declaration, Acknowledgement of Compliance (AoC), to express their confidence that petroleum operations can be pursued by a mobile facility in compliance with the regulation[21]. This declaration is only valid on the NCS. If planning for an operation on the UK sector, one have to get a new declaration, a Safety Case (SC), issued by the UK Health and Safety Executive (The offshore safety directive regulator)[22].

The AoC is issued by the PSA and this declaration is given after the company's application has been evaluated and found to be within the authority criteria. The company defines the mobile facility's intended petroleum activity, its technical condition and the applicant's organization and safety management systems. After all safety-critical nonconformities have been rectified, the PSA will award the vessel with an AoC[21].

4.3.1.1.1 AoC – Island Constructor

Island Offshores vessel, Island Constructor, is awarded with an AoC to operate on the NCS and a SC to operate on the UK sector. However, the declaration has a technical limitation that currently limits the vessels ability to conduct P&A operations. When the AoC was issued, the vessel was permitted to take onboard a fixed volume of fluid returns containing hydrocarbons. That fixed volume is limited to $5m^3$ and constitutes two to three flushes of a closed well during a well intervention with WL, i.e. one flush of the RLWI stack and down to the DHSV equals 1.5-$2m^3$.

The total volume of fluid returns during a P&A operation will vary (i.e. well construction, complexity of the P&A operation, etc), but the volumes are most likely to be greater than $5m^3$. Island Constructor can accommodate $219m^3$ with its integrated LFL tank system (199 m^3) and $20m^3$ tank (integrated in the HC vent system), but temporary tanks can be placed on deck to increase the storage capacity of fluid returns.

To be able to store greater volumes than $5m^3$of fluid returns, a new amendment towards the AoC will have to be submitted and subsequently approved by the PSA.

4.4 Main Subsea Equipment for Well Control

4.4.1 RLWI stack

Figure 9 is an illustration of a RLWI stack during a live well wireline (WL) operation[23]. The assembly could be different due to the manufacturer and/or operation. However, the main components described above is typically standard parts of a WL assembly. This RLWI stack can be used in the preparatory work (phase 0) and with some modification it could be implemented in phase 1 and 2 in a P&A operation using CT. The RLWI stack is divided into three assemblies; the well control package (WCP), lubricator section LS and pressure control head (PCH). The LS consist of the lower lubricator package (LLP), the lubricator (LUB) and the upper lubricator package (ULP).

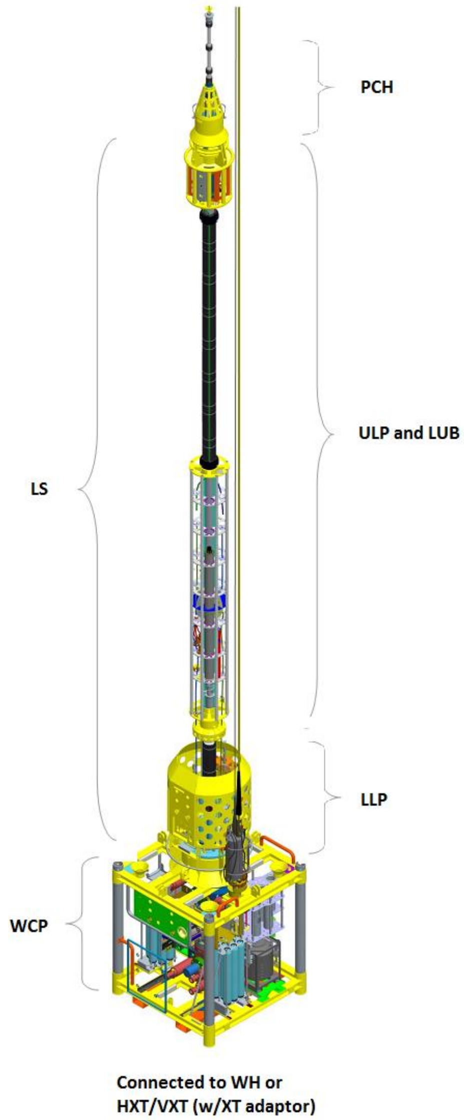

Figure 9: RLWI Stack [23]

The WCP (w/XT adaptor) is installed in the first run, then the LS, without the workstring and PCH, is deployed subsea and hydraulically attached to the XT re-entry hub. In the third and last run, the workstring and PCH is ran as one assembly and will have to be retrieved and run for every bottom hole assembly (BHA) change out. The workstring is accommodated in LUB and the PCH is attached to the ULP. The LUB is then pressurized to working pressure and the operation can commence[24]. Total runs when installing the RLWI stack depends on the vessels capacity (i.e. height of tower, lifting capacity, etc.).

4.4.1.1 XT adaptor

In operations where the intention is to do intervention, i.e. preparatory work in a P&A operation, the lowermost subsea equipment on the RLWI stack is a XT adaptor consisting of a tree running tool (TRT) connector and an adaptor spool. The adaptor spool is an x-over block attached to top of TRT connector interface. The upper part of the adapter spool has a mandrel for attaching the required well control equipment (WCP) with a flanged connection, Speed lock. The RLWI stack is deployed and the XT adaptor is then attached to the subsea XT, enabling WL access in production and annulus bore. The x-over block used on HXT's and VXT's consists of a production –and annulus bore. HXT's does not accommodate WL operations through its annulus bore. Both x-over blocks are fitted with seal subs that will be stung into the XT seal pockets or TH to act as an extension of the production tubing[10].

A XT adaptor is necessary to enable:

- *The RLWI stack to be attached to different subsea XT's*
- *Access to production -or annulus bore when a VXT is used*
- *Installation or retrieval of TH –and annulus plugs*
- *Bullheading and circulation possibility*
- *Control of the VXT (The adaptor distributes hydraulics to required functions on the VXT)*

Figure 10 is an illustration of the XT adaptor for a VXT and shows how it accommodates for accessing both the production- and annulus bore by changing the x-over block 180 degrees. The XT adaptor for a HXT is quite similar, but its production bore on the x-over block is centralized in the TRT connector.

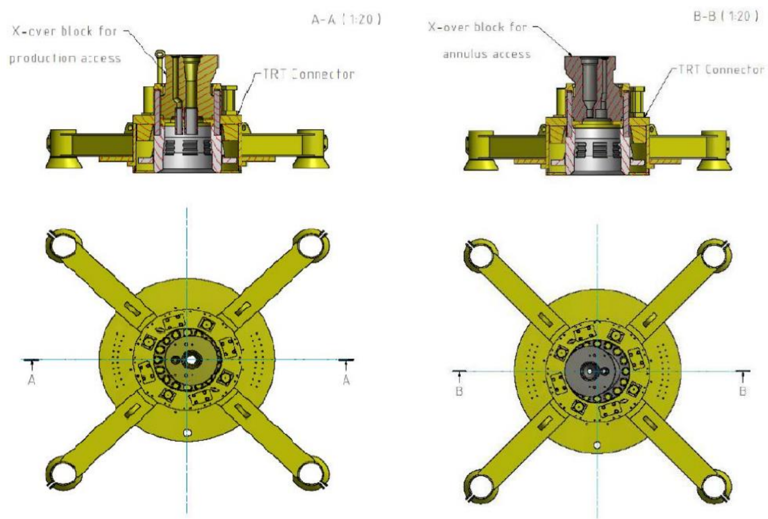

Figure 10: XT adaptor for a VXT [10]

Figure 11 is an illustration of the XT adaptor connected to the HXT re-entry hub and the adaptor spool is connected to the WCP with FMC's Speed Lock connector.

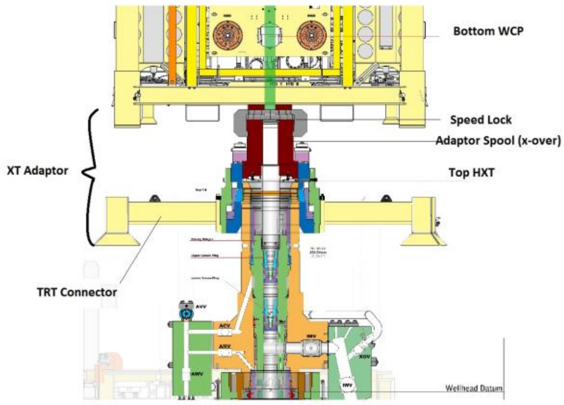

Figure 11: XT adaptor attached to a HXT [25]

4.4.1.2 Well Control Package (WCP)

The WCP has an ID of $7\frac{1}{16}$'' and is installed to ensure pressure control during LWI operations, i.e. providing cutting and sealing capability. The WCP is a pressure containing barrier between the XT and lower lubricator package (LLP) and in general it shall provide the necessary functionality to allow safe and efficient intervention through the XT. It enables flushing of hydrocarbons (HC) back into the well and it provides hydraulic pressure and supply, as well as communication to XT functions[26]. The advantage of using the WCP is its capability of providing pressure control, without recovering the RLWI stack, during intervention with small drill pipe, coiled tubing (CT), wireline (WL) and slickline (SL).

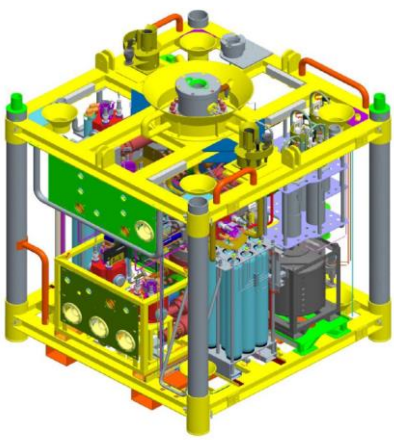

Figure 12: WCP - Well Control Package [26]

Main components[26]:

- *Valve Block (w/ Shear/Seal Ram, Lower and Upper Production Isolation Valve, ++)*
- *Umbilical Termination head (UTH) base*
- *Well kill hub*
- *Subsea Control Module (SCM)*
- *Electric Subsea Control Module (eSCM)*
- *Subsea Hydraulic Power Unit (sHPU)*
- *Accumulator banks*
- *WCP hydraulic Reservoir*
- *XT Module*
- *XT hydraulic reservoir*

4.4.1.3 Lubricator Section (LS)

There are several components that complements the LS and the standard components during WL intervention are the LLP, Lubrication tubular (LUB) and ULP. The LS can vary in length, but it typically has a length limitation due to external forces acting on the total stack. Amongst the available LS on the marked, it is not common to have a LS that can lubricate more than 22m of toolstring length and standard ID is $7\,{}^{1}\!/_{16}$''[24].

The LLP is the lowest component on the LS and it is provided with a safety joint to prevent overload of WH and XT. It is mounted on top of the WCP and it carries the controls equipment, i.e. control modules, power supply, hydraulic pumps and accumulators for all functions on WCP, XT and pressure control head (PCH)[24]. The Lubricator is just a slick tube and a carrier for the grease system for PCH. Common components are grease –reservoir, -pumps and isolation valves. The LUB is designed for WL-, SL -and CT intervention, preventing unnecessary nonproductive time[24]. The ULP is the uppermost component of the LS and is the connection point towards PCH. It is accommodated with a cutting ball valve (CBV) that is capable to cut wire and it acts as a secondary barrier element. A gate valve for circulation is provided to inject fluids, e.g. MEG. The ULP is also designed for WL-, SL -and CT intervention[24].

4.4.1.4 Pressure Control Head (PCH)

The PCH is the active part of the RLWI stack and it has to be retrieved and run for every bottom hole assembly (BHA) change out. It has a liquid grease seal around the moving WL and, in combination with the ULP, LUB and LLP, it constitutes the primary well barrier towards the well. It is complemented with two static mechanical rubber element seals (Upper Stuffing Box (USB) and Dual Stuffing Box (DSB)) around the static wire, two MEG injection points (inside DSB) towards wire for hydrate prevention and a toolcatcher to prevent tool drop down[26]. The PCH cannot be used in CT operations and a solution for this problem is described in section 5.4.6.

4.4.2 Additional Subsea Equipment

4.4.2.1 Subsea Shut-off device (SSD)

The SSD is a 10k and 18 ¾“ ID well control system and is designed to meet the requirements to be able to shear, seal and control the well in the event of an incident without requiring the use of a heavy drilling BOP[27]. Its purpose is to provide a secondary well barrier during a riserless P&A operation. It is similar to the WCP, but the SSD has a larger ID to be able to run and retrieve tubing/casing/liner or CT/drill pipe with large OD BHA. The SSD is attached to the XT/WH and on top one can install necessary subsea equipment, e.g. the RLWI stack for CT or a subsea jacking unit.

The SSD can be installed before the RLWI stack is installed, or it can be installed in a separate run after the RLWI stack is recovered. The main reason for implementing a SSD is to enable retrieval of steel tubulars in open water, e.g. production tubing. The ID of the RLWI stack is too small and its LUB is too short when retrieving steel tubulars, subsequently the RLWI stack has to be recovered.

This device can be handled from a mono-hull vessel and it is a safety device suitable to use when well barriers have been installed in the well, i.e. the well is killed/well is in overbalance (phase 0). The SSD will not be used as the only well control equipment when entering live wells that are in underbalance. Hence, the RLWI stack is installed on top of the SSD. After phase 0, one can install the SSD or remove the RLWI stack (depending on the rig up). When working in the well (i.e. after phase 0), the fluid column will act as the primary WB and the SSD is the secondary WB.

Direct hydraulic umbilical can control the SSD or electrical umbilical's can be connected to a HPU (e.g. ROV), which provide the SSD with hydraulic power. In Chapter 5, an alternative setup where the umbilical is connected to a CT stack will be described. The SSD used in this thesis consists of the following components[10]:

- *18 ¾" H4 hub interface (to LS, if necessary)*
- *One annular ram*
- *4 x 2" ID inlets (for circulation, kill and choke line)*
- *Double seal/shear ram block (Could add a third ram - Slip ram)*
- *18 ¾" H4 connector (to WH)*
- *Wear sleeve can be installed to reduce ID (avoid CT/DP buckling)*

The SSD in Figure 13 is the riserless open water abandonment module (ROAM), which is under development by the Subsea Service Alliance[28].

Figure 13: An example of a SSD - The ROAM Abandonment Module[29]

4.4.2.2 Riserless Mud Recovery System

During a P&A operation, one might need fluid supply or return (e.g. mud and cuttings, metal cuttings/swarf, displacement of fluids, ++). To enable this operation riserless, one need to have a subsea unit that can register if the well is gaining or loosing fluids and facilitate for circulation, i.e. volume control device. Hence, a level sensor is installed inside the WH interface manifold and camera is equipped on top of the funnel for continuous surveillance of the mud/fluid level to avoid mud spill to sea. An electric and hydraulic umbilical is connected to the WH interface manifold to the subsea volume control skid. A second electric and hydraulic umbilical goes from skid to the surface fluid tank (w/level sensor and feed pump)[16].

Figure 14 is an example of the mud recovery system without riser (MRR) provided by IKM Cleandrill that could be used in a P&A operation[30]. The riserless mud recovery (RMR®) system from Enhanced Drilling is used for top-hole drilling. Yet, the basics of fluid and cutting transport is the same as for the MRR system[31]. (NB! There are typically more components/systems than described and illustrated in this section)

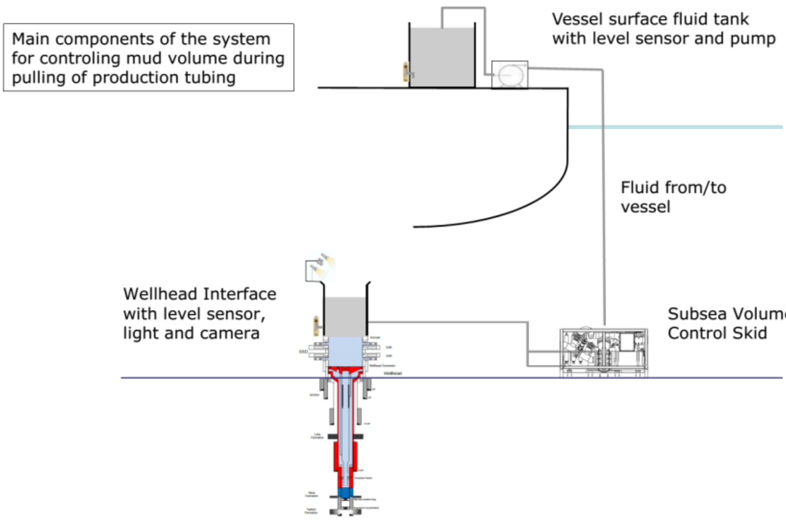

Figure 14: Example of a Riserless Mud Recovery System [16]

4.4.2.3 Subsea Jacking Unit

A subsea jacking system can be fitted above the SSD (e.g. above the max fluid level of the volume control system) to assist with sufficient lifting force when unseating tubing hanger (TH) and/or casing hanger (w/casing hanger seal assembly). In old wells there could be deformed casings, sagged mud particles (barite) and other elements that increase the friction forces when unseating the casing- or tubing hanger. From a RLWI vessels perspective it can be hard to unseat the TH using main winch only. As this system can grip strings with different OD's, one could use this system to hang off strings (e.g. tubing) in a set of pipe slips and the string could be cut in equal sections in a subsea operation. There are some different, but comparable subsea jacking units on the marked. Figure 15 is the Geoprober Gripper Assembly and is just added to illustrate the concept of such a system described[32].

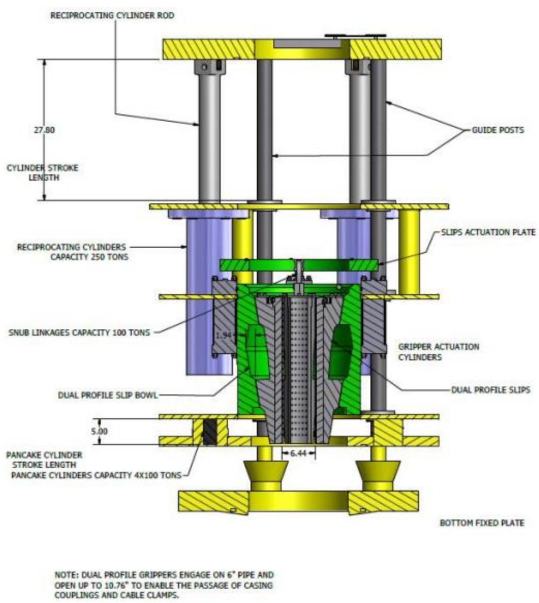

Figure 15: Geoprober Gripper Assembly [32]

4.4.2.4 Comment

After the preparatory work (phase 0), the idea is to install an assembly to pull steel tubulars. The SSD could be installed on top of subsea XT or WH (if XT is removed) together with a mud recovery system. A subsea jacking mechanism can be attached above the SSD and supply the workstring with extra pulling force.

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5 Riserless Coiled Tubing using RLWI Concept

The CT concept was developed in the early 1960's and provided the user to do pumping and mechanical operations[17]. CT is commonly used on platforms for intervention purposes of wells, but is also used on jack up rigs and semi-subs for intervention on subsea wells[33]. Typical applications are well cleanouts, selective stimulation and cementing/shutting off water zones[34]. They can be used for live well interventions with HC present in the well provided that sufficient barriers are in place.

CT has already been operated riserless from a RLWI vessel (e.g. Core drilling on the Rogfast project and Pilot Hole on the Butch field), but this operation did not require any well control equipment or returns of HC[16]. The next and more demanding step is to conventionalize the concept of performing well interventions on live subsea wells riserless, and more specifically permanent P&A. The fundamental CT topside equipment is more or less the same for all CT operations regardless of dry or wet XT.

5.1 Standard CT Equipment and Operation

This is an introduction of the standard CT equipment and operations performed from an intervention unit (semi-sub/jack-up) and a platform. Even though the CT topside equipment is quite similar, there are some differences in the rig up when comparing subsea and platform wells.

A CT is a continuous and flexible steel tubular manufactured in predefined lengths and spooled onto a take-up reel. A traditional CT set up consists of a shear seal ram, BOP, strippers, injector head, gooseneck, CT reel (c/w string), control cabin, power pack, and pumps[17].

Its main advantage compared to conventional drill pipe is the reduced trip time, safe and efficient well intervention, reduced crew/personnel requirements, and cost may be significantly reduced[17]. When tripping in or out a live well, one of the CTs benefits are that it can pump continuously while tripping and no stops are required to make up connections.

Due to the CT pumping and mechanical application, it can be applied in several types of interventions. There are some subgroups to these two applications that can be applied in a P&A operation.

Pumping applications for P&A purposes[33]:

- *Cutting tubulars with fluid (abrasive cutting)*
- *Pumping slurry plugs*
- *Pumping cement plugs*
- *Run downhole motors*
- *Zone isolation*
- *Wash annulus*
- *Scale removal*
- *Removal of wax, HC, or hydrate plugs*

Mechanical applications for P&A purposes:

- *Cutting tubulars (mechanical - hydraulic powered)*
- *Perforating*
- *Setting a plug or packer*
- *Fishing*
- *Scale removal*

When using CT during an intervention, the lowermost part of the topside CT rig up is either connected to the surface XT or to a surface test tree. The surface test tree is an extension of the subsea XT, i.e. a workover riser (WOR) w/disconnector is linking the subsea XT to the surface test tree. This type of rig up applies for semi-subs, drillships and it could also be applied for jack-ups[33]. The CT rig up shall be static during operation. To ensure static conditions on a moving rig, one have to compensate for the movements. A coiled tubing tension lift frame accommodates the CT BOP, injector and gooseneck, and this frame is hooked to and compensated by the active heave compensation (AHC) system to keep a constant tension relief at the base of the WOR. This frame is also accommodated with a heave compensation system as a backup to the primary AHC system[33].

5.2 Riserless Coiled Tubing (RLCT)

The idea of RLCT system is to perform live well interventions and drilling operations. The CT substitutes the riser; it is now a well barrier element contributing as an element in the well barrier envelope. As the CT operation is performed riserless, it is subjected to environmental loads like e.g. sea currents, same as a work over riser (WOR). However, the riserless CT system has the ability to work in a harsher environment and have a larger operational window than a conventional WOR from a Monohull vessel. While WOR operations often is limited by the emergency quick disconnect (EQD) timing and loads on the WH this is not any issue for riserless CT operations[35].

The benefit of the RLCT system is that it works similar to manage pressure drilling (MPD) operations, the well control package and stripper seals the well and return pressure can be controlled by the choke manifold on the vessel. Depending on fracture pressure of the formation or existing well casing/tubing there is normally not any requirements for a subsea booster pump or similar subsea. However, it would be necessary if the pressure loss in annulus and return hose exceeds the fracture pressure[35]. Using the riserless mud recovery system, described in section 4.4.2.2, one can route the returns back to the vessel for separation and storage. Another option is to route the returns through the production flowline and up to a platform (production facility).

By removing the WOR the operational criteria's increases and it will be possible to work in shallower water depths, and the time to run the WOR and test it is saved. It will also be less WH fatigue when working on water depths less than 300m, less time devoted to change the tool string and safer working environment on deck when using the RLCT system[35]. The RLCT system's challenges compared to a WOR are:

- *Shorter BHA (decided by the length of the lubricator on stack)*
- *CT string is prone to pinhole or being parted; Critical if not using green chemicals*
- *Need a hose to facilitate returns from sea bottom to vessel*

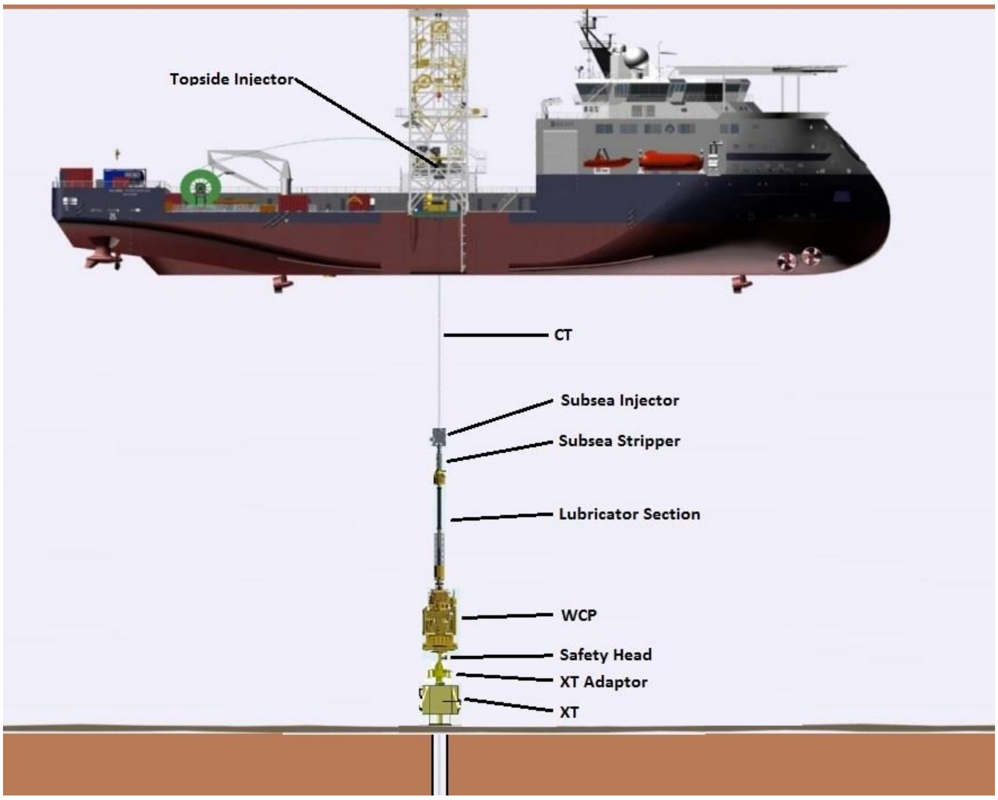


Figure 16: General RLCT equipment on Island Constructor[35]

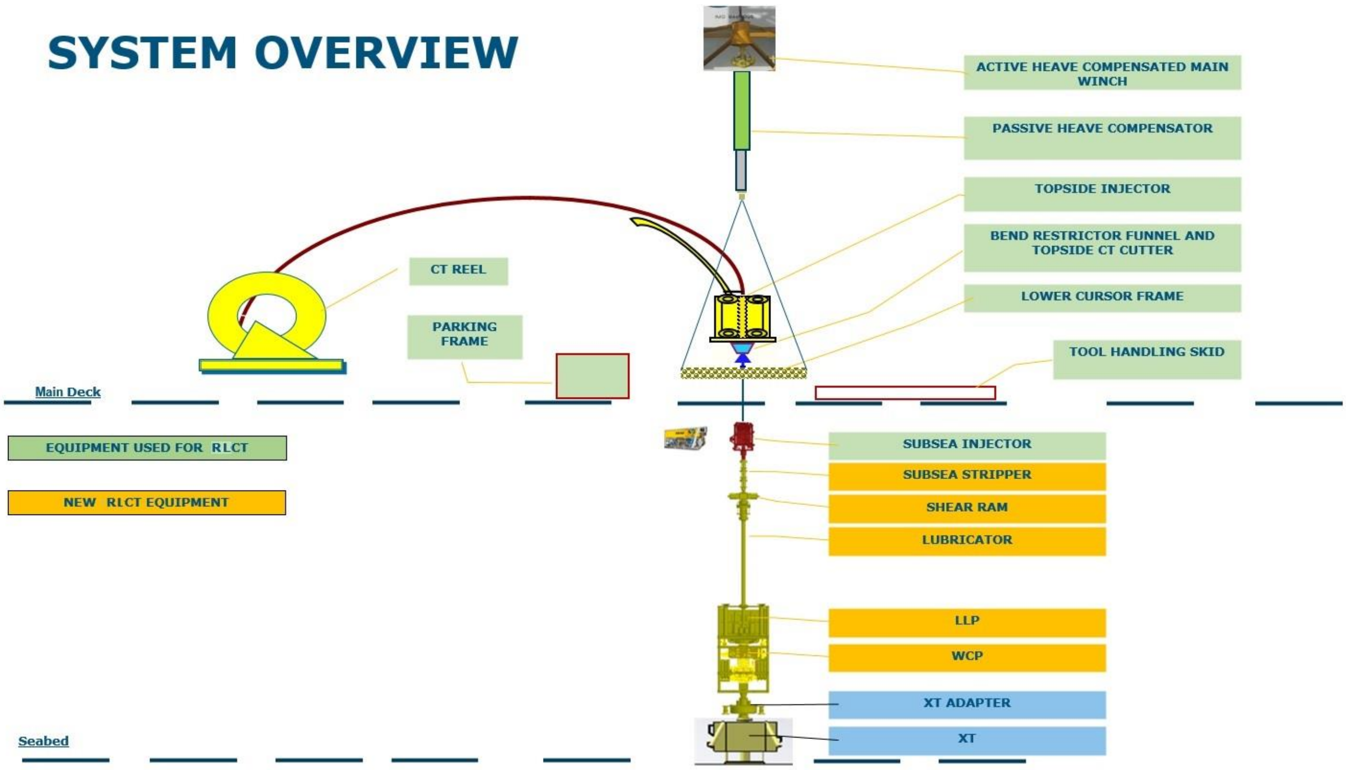


Figure 17: Existing and new RLCT Equipment[36]

Figure 17 is an illustration of the RLCT system and its current status. Most of the equipment marked as yellow exists at the marked today. Nevertheless, the equipment has never been used in combination with a CT rig up in open water. As seen in Figure 18, the subsea stripper is the only equipment that is new. The subsea stripper is developed, but remains to be tested.

The RLWI stack described in 4.4.1 is the existing stack used in WL operations. The new stack for CT has some small modifications related to safety devices and pressure control and will be presented in the next section. The purpose of this modification is to allow for both CT and WL operations without changing the whole stack. This universal stack shall reduce the non-productive time when changing from WL to CT.

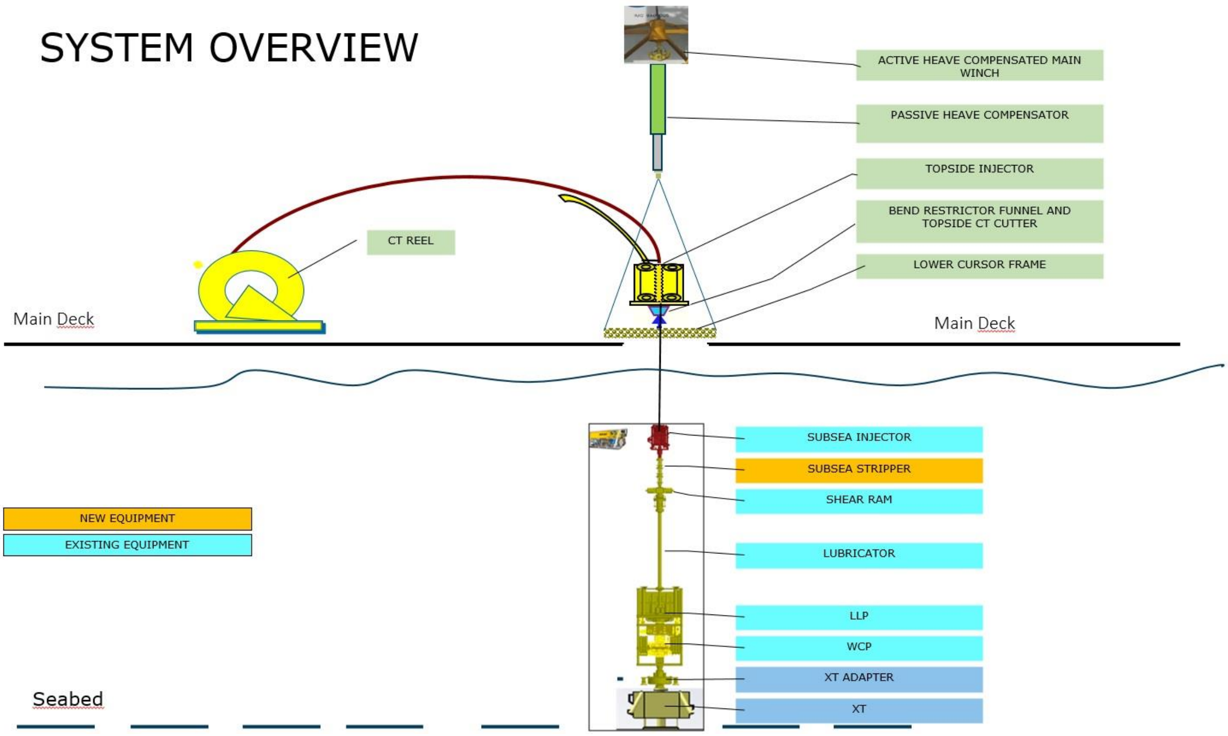


Figure 18: New and Existing Equipment[31]

5.3 Topside Equipment

The main components are listed in section 5.1 and will be applied for an RLCT operation. However, some of equipment used on a RLWI vessel is not mentioned nor described, and will therefore have to be explained. Figure 19 illustrates the rig up of the topside equipment used in an RLCT operation.

The Parking & Service frame is used to park the topside –and subsea injector on main deck and provide service access to the injector heads by permanent gangways and stairs. The structure of the frame shall create a safe working environment below the subsea injector when stabbing coil, installing CT end connector or installing bottom hole assembly (BHA). This frame is used for skidding the injector heads from its parking positions on aft deck and into the center of the mono pool. Prior to deployments of the SSI, both injectors, BHA and subsea stripper are lifted off the parking and service frame. The “lower part” of the parking and service frame will then be skidded empty out of the tower[35].

During operation the topside injector remains in the tower and is docked into and laterally guided by the module handling tower’s lower cursor frame.

For safe handling of large toolstrings (BHA), a separate tool handling skid is used.

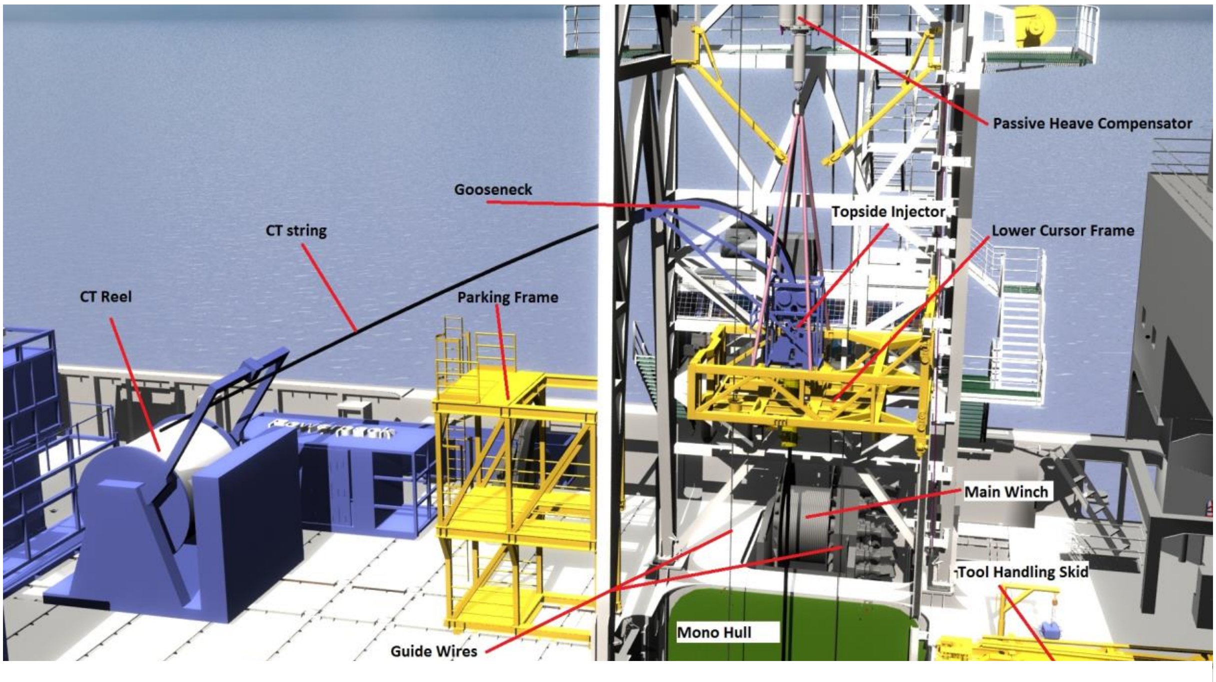


Figure 19: Overview of the Topside Equipment[32]

5.4 RLCT Stack (Subsea Equipment)

The main difference between the existing RLWI system currently used and a new RLCT system is that the RLCT stack have a lubricator and connectors with higher capacity to handle the extra load from the coiled tubing head (CTH), control system and safety system for CT operations, separate return line from the WCP and upgraded main bore valves with cutting capabilities for CT and a pipe slip combination ram. The new RLCT system can be used both for regular WL operations with PCH installed on top of the lubricator and a CTH for CT operations, which means that one only have to change the CTH to a PCH. All umbilical's connected from the stack to the vessel are fitted with emergency quick disconnect (EQD) to enable a quick disconnect in case of an event that requires disconnection[35].

5.4.1 XT Adaptor

Will be the same as described in section 4.4.1.1.

5.4.2 Safety Head

This is a cutting valve often named as safety head. It can be either a ram type or gate type valve. The safety head is only to be actuated in emergency situations and is part of the well control system, emergency shut down (ESD) and EQD sequence[35].

5.4.3 WCP

The WCP will almost be the same as described in section 4.4.1.2. This safety device acts as the secondary well barrier during live well intervention. Remember that this safety device is not the same as the Subsea shut-off device (SSD). The WCP is always used when entering a live subsea well (underbalanced) and it has a smaller ID.

5.4.4 LLP

Will be the same as described in section 4.4.1.3, but in addition it is accommodated with control equipment supplying the upper seal/shear ram (USSR), subsea strippers and CT head (CTH). This LLP is new and modified prior to suit both WL and CT operations.

5.4.5 ULP

The ULP on the new RLCT stack contains a lubricator, an upper shear/seal ram (USSR) and serve as temporary subsea storage of the tool string prior to deployment in the well and after retrieval from the well. The ULP may also include a safety joint. The terminology used on the different sections on the new RLCT stack's are a bit different from what is described in section 4.4.1.3.

5.4.6 Coiled Tubing Head (CTH)

The CTH is the sealing section and subsea injector (SSI), it includes the Stripper, buckling guide, SSI and subsea emergency quick disconnect (EQD) cutter. The CTH assembly act as a barrier element in the well control system and provides sealing function (stripper) around the moving CT string[36]. The subsea EQD cutter is attached on top of SSI and fitted with pre-charged accumulators to give pressure support to the cutter.

In wireline mode, the CTH is replaced with a PCH that includes flow tubes, stuffing box and tool catcher.

5.4.7 Additional RLCT Equipment

5.4.7.1 Subsea and Topside Injector

This is a description of both injectors and why they are applied during RLCT operations. When the CT string is deployed subsea from a RLWI vessel, it has residual stresses distributed in the material and is not allowed to be deployed fully vertical into the water. The residual stresses are a result of the material exceeding its yield strength when being operated in the plastic region from the reel to the topside injector (TSI), i.e. plastic strain (deformation). The CT string is in tension on one side of its neutral axis and in compression on the other, causing a residual moment in the tubular. When the CT string leaves the topside injector, it is straightened until there is no more residual moment. Because the bending cycle's plastically deforms the CT string, it will have a curve after leaving the injector. The CT string tends to straighten from the radius it had been forces to, to its residual radius. Even though the total momentum is zero, there are still residual stresses resulting in a curved CT string. This curve has a radius, referred to as the radius of curvature. The residual curvature is the reciprocal of the residual radius of curvature[37].

To avoid the curvature in CT string and risk of buckling, one introduce a second injector. This injector will be a subsea injector (SSI) and is introduced to enable tension in the CT string between the topside and subsea injector. Figure 20 illustrates the rig up before it is deployed subsea. The SSI is assisting with its weight during deployment, assuring that the CT string is kept straight until it lands on top of ULP. It will be 2-4 tons weight on top of the ULP to avoid buckling above the SSI. Additional force and weight from the SSI and BHA assures tension in the CT string.

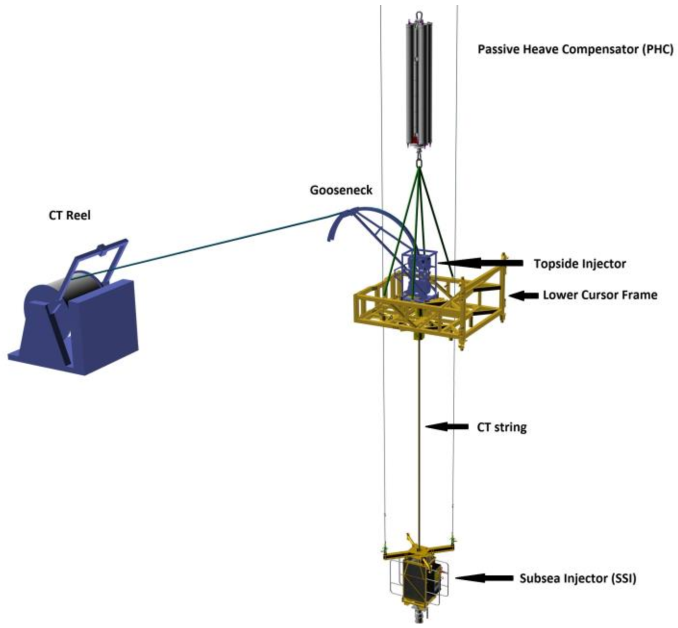


Figure 20: Topside and Subsea Injectors [35]

A feeder could be mounted on the CT reel to apply tension (reel back tension) between the reel and topside injector. It is important to keep an adequate back tension to ensure that the work string is spooled correctly on and off the reel[38].

The SSI is operated identical to a standard injector head after the CTH has been connected to the ULP. The TSI's main task is to keep the CT string in constant tension between the injector heads. The SSI is designed with attention to be as light as possible and to provide enough pulling force. The SSI and strippers are lowered down as a stack together with the work string, where the SSI constitutes the uppermost subsea component on a CT stack in an RLCT system. There are two guide wires that could be installed from the vessel to the guide posts on the permanent guide base (PGB) and two guidewires could be installed on the SSI to keep it in tension. All four wires are used to easily run and retrieve subsea equipment and to avoid that the work string and associated equipment get a drift off, but it could also be deployed guide-line less. It is then latched onto to the ULP and the operation can commence. If changing the BHA, one have to pull the CTH together with the work string and BHA. When pulling the SSI and strippers between the runs, one have the ability to visually inspect the equipment[35].

The topside and subsea injectors have the same functionalities, but the SSI is designed to withstand external loads and it shall provide the CT string with snubbing force. The topside injector's main task is to keep the CT string with a constant tension. Hence, it have to cooperate with the SSI and the AHC system.

5.4.7.2 Strippers

The strippers (stuffing box) are designed to create a dynamic seal around the work string and are the primary well control device during a CT operation. Its purpose is to seal around the work string while running in or pulling out of the well. For an RLCT system SSI is attached on top of the strippers and ran as an assembly together with the work string. The assembly is then installed on top of the CT stack. Each stripper consist of an independent hydraulically actuated packers mounted on top of each other. This rig up consist of three individual strippers and are typically pressure rated up to 10,000 psi. By having more than one individual stripper, one increase its reliability; i.e. two packers are active during operation, while the other is held in reserve (deactivated). When the subsea stripper is activated during operation; the first and uppermost packer element shall work as an environmental seal to avoid seawater intrusion, second packer element shall seal and work as the primary barrier when, and the third packer element shall act as a backup in case of failure.

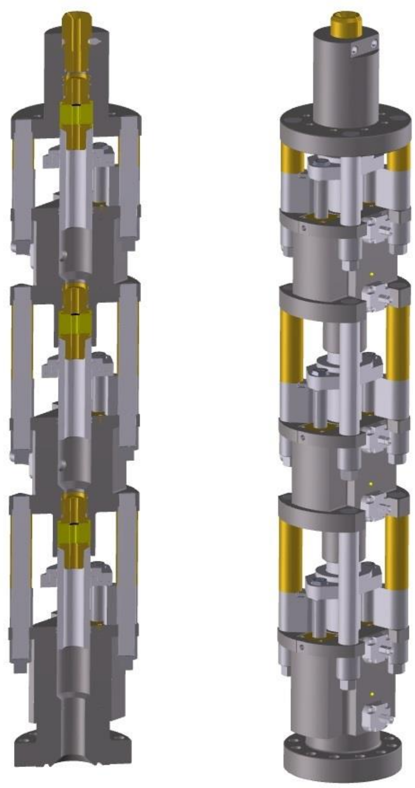


Figure 21: Cross sectional view of a stripper rig up [35]

Each packer element can be changed topside to be compatible with different pipe sizes or if they are damaged/worn out. Subsea strippers have never been used and there is an uncertainty of the packer elements expected lifetime during operation[10].

The subsea stripper will act as the primary barrier during live well intervention and as a secondary barrier if used during P&A, i.e. abnormal pressure and/or hydrocarbons in the annuli (e.g. A-, B – or C-annulus) during cut and pull of casing strings.

5.4.8 Rig Up Sequence and Deployment of RLCT Stack

This is a basic description of an RLCT rig up and should give an overview of how it is deployed. It is designed to be deployed as one unit and guideline less. The RLCT stack is deployed in two runs, i.e. the well control system (WCS) in the first run and the CTH or PCH in the second run.

Deployment of WCS

- *Skid WCS into moonpool and connect running tool (RT) to main winch and engage lower cursor frame for lateral guiding of WCS*
- *Lift WCS free of skidding pallet, skid pallet out of moonpool*
- *Open moonpool hatches and deploy GW if req.*
- *Deploy XT adapter and Well Control System as one assembly.*
- *Land Assembly on XT, disconnect RT and lock connector.*
- *Connect umbilical*
- *Flush out seawater and Barrier test WCS*

Deployment of PCH or CTH (CTH used as reference)

- *Skid CTH into moonpool*
- *Build BHA and connect to CT quick connector*
- *Lift PCH or CTH off parking and service frame*
- *Skid parking and service frame away from moonpool*
- *Open moonpool hatches and deploy GW if req.*

- *Deploy CTH and land out on top of ULP*
- *Connect ROV to CTH and function test*
- *Flush out seawater from CTH with MEG*
- *Barrier test CTH connector and stripper.*

After all the tests are successfully completed, the system is ready for opening valves and start deploying BHA into the well.

5.5 Summary of the Intervention Stacks used in this Thesis.

Since there are different types of intervention stacks described in this thesis, a short summary will be presented.

- *The present RLWI stack used on Island Constructor is delivered by FMC Technologies (FMC Mark II system) and provides WL operations.*
- *The new RLCT stack is a universal stack, meaning it shall allow CT – and WL operations by changing out the PCH/CTH. This stack is under development and designed to be used on Island Offshores new vessel, Island Navigator. However, without any modifications it could also be applied on Island Constructor.*
- *The intention is to modify the existing RLWI stack used on Island Constructor to allow both WL – and CT operations.*

5.6 Comments

The existing RLWI stack and the new RLCT stack are both designed with an ID of 7$^{1}/_{16}$" and it can limit the operational scope of work during an P&A operation. One possibility is to modify the new RLCT stack by removing the WCP and replace it with the SSD to be able to retrieve tubing/casing, run larger OD tools or other equipment through the stack and well control equipment. The SSD has an 18¾" ID and with a ULP and LLP with the same ID one have full wellbore access. Section 11.3 is a base case where this re-design of the RLCT stack has been implemented. Note that the existing equipment supports general WL operations with the ability to circulate wellbore.

6 Typical P&A procedure of subsea wells on the NCS

P&A operations of subsea wells are currently PP&A by semi-subs or jack-ups, but some of the phases are or can be performed by a RLWI vessel. In this chapter, an example of a P&A operation with the provided technology and operational experience is given to illustrate present practice of PP&A. The example is based on the current practice and experience of a RLWI vessels application to conduct phase 0 and 3.

6.1 Well X

Well X is an old subsea single satellite well that is shut-in due to low revenue and therefore no or little turnover. The well is fitted with a pipeline from XT to production facility on the host platform. Since this is not removed, one can use this pipeline to transport fluid returns. This subsea well is an oil producer and the formations in the overburden has no flowing potential. All WBE's are within the requirements and the two required WB envelopes are intact. A pressure and temperature gauge is located a few meters above the production packer.

It is important to clarify that this well is just an example and the basic steps are shown chronologically. Figure 23 is a self-drawn storyboard of the operational sequences for this operation, created with the well barrier schematic illustration tool owned by WellBarrier AS[2].

6.1.1 Phase 0

The preparatory work is performed with a RLWI vessel and the following operational steps is an example of how to execute this phase.

- *Retrieve tree cap and clean WH*
- *Install RLWI Stack (FMC Mark II system)*
- *(If it is a HXT, one would have to remove the crown plugs now to be able to enter the well)*
- *Drift run*
- *Kill well by bullheading MEG/Seawater into well prior to setting deep set plug*

[2] Wellbarrier AS - https://www.wellbarrier.com

- *Set Mechanical Plug in tailpipe using WL and leak test plug and tubing*
- *Cut Tubing above production packer*
- *Circulate annulus and main bore; fluid return through A-annulus and the annulus wing valve (AWV) and sent to production facility topside via production pipeline.*
- *Leak test the primary barrier(production packer and deep set plug) from above*
- *Set plug in tubing hanger (annulus plug is also necessary if it is a VXT) and pressure test registering*
- *Retrieve Stack*
- *If it is a VXT, this could be removed at this point (together with the Stack)*
- *Install corrosion cap and net cover*

6.1.2 Phase 1

This is the reservoir abandonment and is conducted with a semi-sub.

- *Rig up BOP and riser*
- *Retrieve shallow set plugs*
- *Pull tubing w/DP and THERT*
- *Logging of 9⅝" csg may be required. In this case, the old cement bond log (CBL) shows good quality cement.*
- *RIH with cement stinger on DP and install the primary well barrier inside the 9⅝" csg on top of the mechanical plug.*
- *Wait on Cement (WOC)*
- *Tag top of cement (pressure test not necessary – foundation (plug) is pressure tested)*
- *Install the secondary well barrier inside the 9⅝" csg with the cement stinger*
- *WOC*
- *Tag top of cement*
- *POOH*

6.1.3 Phase 2

Many wells have formations with flowing potential in the overburden and requires independent WBs to fulfill the given requirements in NORSOK D-010. This is not included in this example, but the installation of the open hole to surface barrier is a part of this phase and will be covered. This phase is conducted by a semi-sub.

1. *RIH with a mechanical/hydraulic cutter on DP and cut & pull 9⅝" csg 150m below WH*
2. *Circulate out new exposed fluid (e.g. residual HC)*
3. *RIH with a mechanical/hydraulic cutter on DP and cut & pull 13⅜" csg 145m below WH*
4. *Circulate out new exposed fluid (e.g. residual HC) and clean up well*
5. *Logging of 20" csg may be required. In this case, the old CBL shows good quality cement.*
6. *Install mechanical plug above 13⅜" csg cut.*
7. *Install a balanced cement plug (Open hole to Surface Barrier)*
8. *WOC*
9. *Tag and Pressure test*
10. *Pull marine riser and BOP*
11. *Install corrosion cap and net cover*

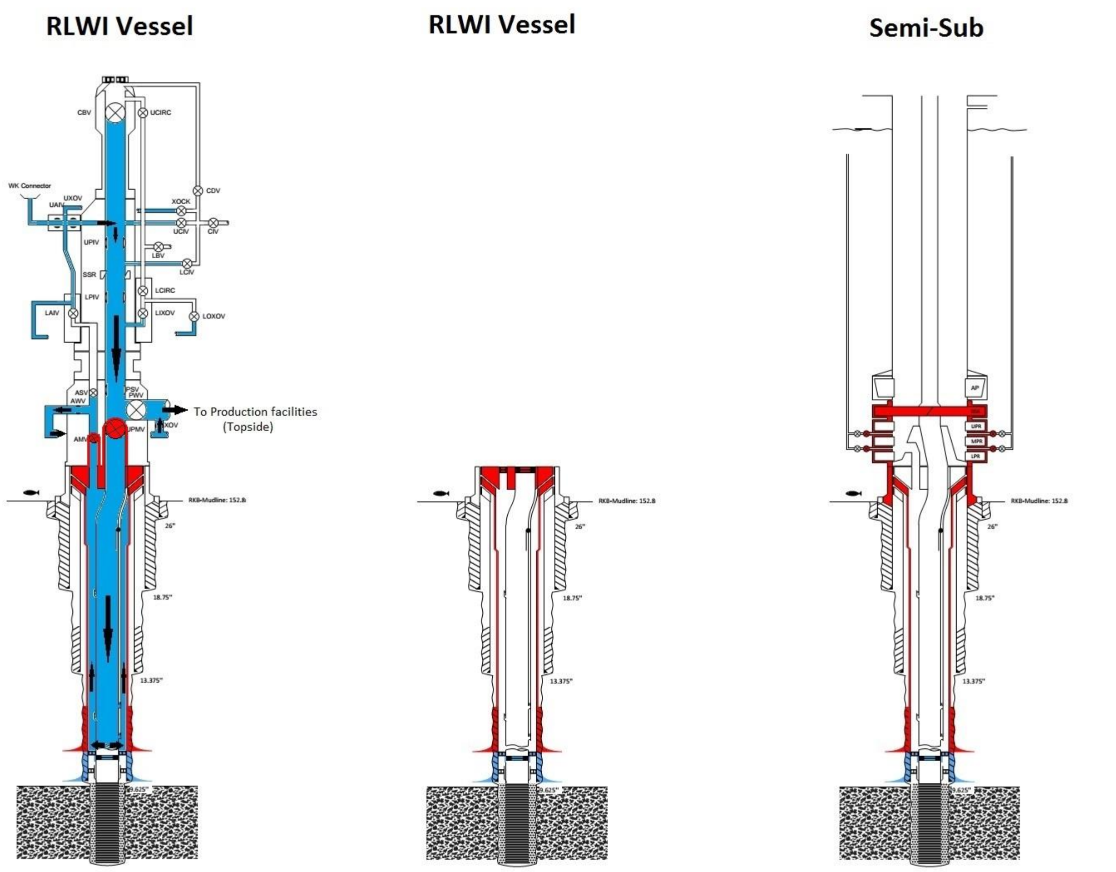
6.1.4 Phase 3

This phase could be conducted by a RLWI vessel. In order to reduce the costs, this phase is conducted with a light construction vessel (LCV) because of its lower day rate. It is a straight forward wireline and lifting operation without the requirement of well control equipment. Hence, a LCV is sufficient during phase 3.

- *Removal of corrosion cap and net cover*
- *RIH with a mechanical/hydraulic/electrical cutter and cut casing strings below WH (approx. 3-5m below seabed)*
- *Retrieve the WH and casing strings (surface csg and conductor)*
- *Inspection with ROV*

6.1.5 WBS of the Operational Sequence

The WBS illustrates the status of the well, either during operation or how it is left before or after the operation. It is important to know which WBE that constitutes the WB envelope to ensure a safe and efficient operation. The Primary WB is the first envelope that enclosure the reservoir pressure and the secondary WB is the last possible option to close in the well avoiding reservoir pressure to reach the surface (e.g. Blind/Shear ram on a BOP). The third WBS is a good example where the primary – and secondary WB are illustrated. Hence, all the upcoming WBSs in the base cases will be illustrated with its primary WB and its last optional secondary WB.



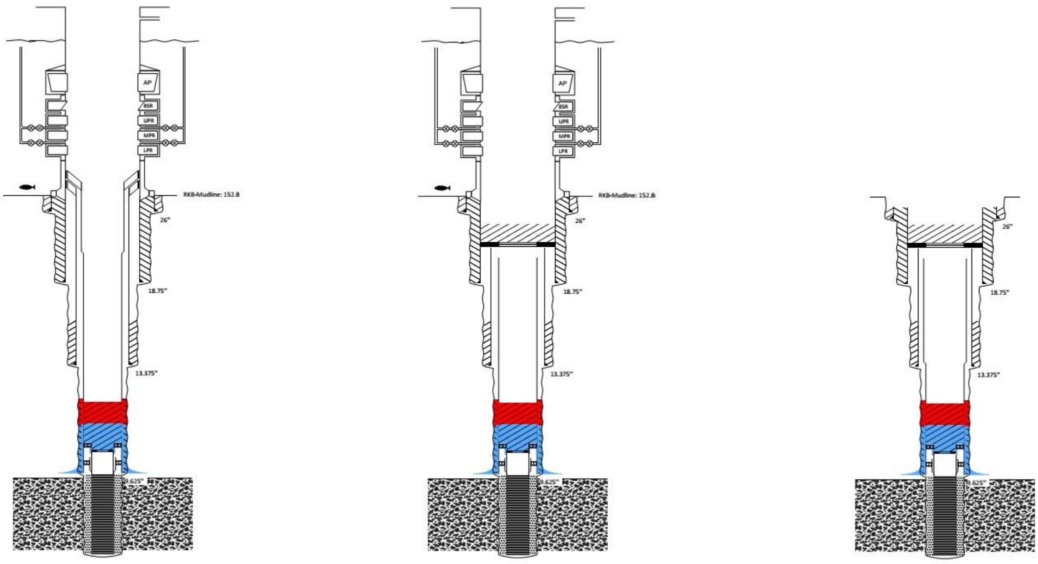
US 5.6.v-1 rev. 1 - Production well, Phase 0 - circulation of main bore and A-annulus

US 5.6.v-2 rev.1 - Production well, Phase 0 - Completed and ready for Phase 1

US 5.6.v-3 rev. 1 - Production well, Phase 1 - Tubing Retrieval

Figure 22: P&A Storyboard 1

Semi-Sub | **Semi-Sub** | **Light Construction Vessel**



US 5.6.v-4 rev.1 - Production well, Phase 1 - Primary and Secondary WB installed

US 5.6.v-5 rev.1 - Production well, Phase 2 - Open Hole to Surface Barrier

US 5.6.v-6 rev.1 - Production well, Phase 3 - WH and Conductor Removal

Figure 23: P&A Storyboard 2

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7 Material Selection

To ensure a good quality permanent WB job, one have to consider several placement issues:

- *Place the plug at the correct location*
- *Prevent cement contamination*
- *Ensure sufficient thickening time at downhole temperature to complete the placement and well cleanup*
- *Ensure that pressure and mechanical strength limits are not exceeded during all stages*

These bullet points are considered as objectives during the cement job evaluation[39]. One often refer to cement jobs, but keep in mind that there are other materials than cement to be used as a permanent WB.

There are several tools and techniques for placing a permanent WB:

- *Balanced plug (cement spool, through tubing cementing)*
- *Dump bailer (typical WL)*
- *Pump and squeeze*
- *Two-plug method (for maximum accuracy and minimum cement contamination)*
- *Mechanically supported method (with jet-hole cleaning)*
- *Flexible bags*
- *Inflatable through-tubing packers*
- *Umbrella-shaped membranes*
- *Coiled tubing placement (economical method to accurately place small volumes of cement slurry)*

7.1 Plugging Materials

There are several suppliers of plugging materials in the world and the mutual characteristics of these materials are, with reference to section 2.2.2, that they shall provide long term integrity (eternal perspective), be impermeable, non-shrinking, able to withstand mechanical loads/impact, resistant to chemicals/substances, ensure bonding to steel and not be harmful to the steel tubulars integrity[4].

It is important to understand the properties of the material used as a permanent WB to ensure no leakages in the future. Figure 24 shows the potential leak paths in and around a bulk material[40]. These root causes for leakages shall be considered in the initial design of a new plugging material. There are several material types for permanent WB that can be applied during a P&A operation and these are[41]:

- *Cement/Ceramics*
- *Grouts (non-setting)*
- *Thermosetting polymers and composites*
- *Thermoplastic polymers and composites*
- *Formation*
- *Gels*
- *Glass*
- *Metals*

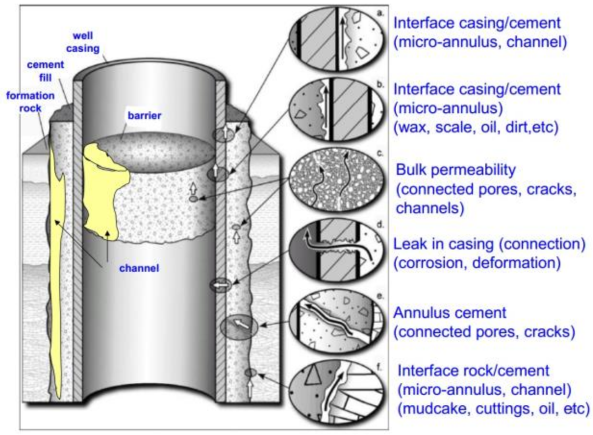

Figure 24: Barrier failure modes [40]

7.1.1 Cement

Cement is the most common material to use during well operations and its properties are well known compared to other materials. The conventional cement used on the NCS (and in the world) is Portland cement class G. The reason for that is its responsiveness for various additives to change the properties of cement slurry (i.e. setting time, density, accelerators, retarders, etc.) and it is a low cost material[42].

Portland cement, Class G, is mostly used in offshore wells because it sets and develop compressive strength through hydration, not by drying out. The density of the cement can be adjusted and a typical cement slurry has a density of 1890 kg/m^3 [42]. If the fracture pressure is low, one can use a cement slurry with low density. Either a low density cement slurry as e.g. a lead cement is used or one could add nitrogen to create foam cement[43].

7.1.2 Thermal Activated Resins

This multicomponent polymer resin based liquid plugging material has a curing process activated by temperature. It has an advantage over traditional cement that it has a wider density range (0.75 to 2.5 SG) and its curing process and curing time can be adjusted to suit the predetermined temperatures (20 – 150 ˚C) of formation or the location of the plug[44].

Due to its ability to be designed in a range of densities and viscosities, and since it holds mechanical properties that are favorable in terms of the criteria of a permanent plug, it has applications that could be advantageous during placement of both external - and internal barriers[44].

7.1.3 Unconsolidated Materials

To get a fracture-less and formable well barrier element that is gas-tight, one can use unconsolidated material. An unconsolidated material such as SandaBand is thermodynamically stable because its sealing property is decided by the solids particle-size distribution (PSD) and bound water only. No influx through the wellbore will occur due to the closely packed particles and absence of free water that keeps the entire column homogeneous and assures that no internal redistribution of particles may occur. As a Bingham Fluid, it can be pumped as a liquid and turn non rigid solid when reaching its depth of placement[45].

For P&A purposes, this sand-slurry could be applied as the primary well barrier during phase 1 or as an external barrier where there is no cement. It does not require to be tagged and the period of waiting for cement curing is eliminated. The contamination issues and other factors does not affect the critical transition period before sufficient compressive strength is achieved. The sand-slurry can be placed by pumping it through a pipe or hose without too large restrictions (e.g. choke or nozzles) into the reservoir zone. To hold the slurry in place, one can install a few meters of cement on top (i.e. increased reliability of the long term integrity)[45].

7.1.4 Metal

Casing strings are defined as a WBE in a permanent WB. However, there is a new field proven metal plug that could be used in a P&A operation. This metal plug, the so-called Wel-Lok M2M plug, is a bismuth based alloy and is developed by BiSN Oil Tools. This metal plug has viscosity similar to water, it expands like ice, density of lead (10 SG) and it is corrosion resistant[46].

It is ran on standard WL or CT and can by-pass restrictions in casing, cope with damaged and corroded casing, not affected by H_2S, acid or CO_2, it is a gas tight metal to metal seal and it can be set without the need of any foundation[46].

When the assembly is located at its position in the well, one initiate a chemical reaction that increases the temperature substantially and melts the bismuth. The bismuth melts at 271˚C and turn to solid once the temperature reduces by 1˚C[46].

These applications could be beneficial when there is a restriction in the wellbore, preventing a bridge plug to be installed for P&A – or TA purposes.

7.1.5 Formation

There are some cases where shale formation has been used as an approved external well barrier element[47]. This excludes the use of cement and can reduce the cost of operation in terms of materials and time. The shale experiences high overburden pressure, which exceeds its formation strength and results in collapse. This collapse can create a good vertical seal towards the casing, but it can be difficult to confirm it with bonding logs.

Due to high uncertainty if the shale formation act as a barrier or not when planning for P&A, this type of barrier will not be covered in this thesis work.

8 P&A Methods

There are different ways to establish permanent WB during a P&A operation. A key factor is to utilize the knowledge of applicable technologies to reduce the total expenditures of the operation. Each subsea well can be challenging to P&A, requiring a specific method and/or technology to be P&A in a prudent manner. There are several suppliers of equipment and tools that can be applied in a P&A operation to reduce the duration. The appropriate method or combination of methods is chosen as a result of the evaluation of logs and the condition of the well. This chapter will only describe the field proven technology that are currently used on subsea wells.

8.1 Cut and Pull Casing

During a P&A operation and after the production tubing is recovered, there are some cases where one or several casings would have to be removed. A casing string is removed to expose the next casing or formation, prior to conduct logging, set a permanent WB or prepare for cut and pull the next casing. The WB can be set into virgin formation by removing casing(s) or as an internal WBE towards the new exposed casing with verified external cement. The risk of pressure differentials and/or possible leak paths will therefore be reduced due to casing removal. Collapsed formation, settled mud particles, or traces of cement because of poor cement job are some factors that can be challenging during cut and pull of casing strings.

Sometimes a casing string need to be removed to be able to access, log and verify good cement. The industry tries to develop new technologies to make it possible to log through several casing strings. Such technology has not been invented or proven, but there are companies that are doing research within that field. The industry can reduce the P&A expenses dramatically by inventing a multiple casing string logging tool.

The casing string is cut with a designated tool for the respective job and pulled out of the hole. The transition between annulus cement and fluid in annulus needs to be located, referred to as the free point. One might find it impossible to pull a casing string out of the hole if the executed cut is in the annulus cement zone. The free point can be found by performing a stretch test when pulling the casing string or by logging the cement[48]. Old information about

TOC in annulus can be misleading due to miscalculations regarding cement volume and the TOC can therefore be at a lower depth than given. Normally the first cut is performed with a safety margin (over the given TOC in annulus) and the casing string is removed if possible. If the casing string is stuck it has to be cut and pulled in several steps. This will lead to increased tripping time and costs due to a higher time consumption.

Before the casing can be cut and pulled, some safety measurements have to be done in order to reduce the risks associated with casing removal. A normal procedure is to punch the casing at the depth of the cut to ensure that there is no trapped HC. A fixed volume can be circulated out. If a constant inflow of HC occurs, one have to stop the inflow before the cut and pull can commence. The cut can be performed if the well conditions are stable. Subsequently the casing hanger seal assembly is retrieved in a separate run and then a spear can latch into the casing and pull it out of the well.

8.2 Section Milling (SM)

The casing string might not be possible to pull in cases where the casing string is e.g. fully or partly cemented or stuck due to obstructions in annulus. SM is the method to create a cross-sectional barrier towards direct exposed formation where the annular material disqualifies as an annular barrier[49].

To remove a section of casing strings (e.g. casing, liner, tubing, packer), SM is applied. The required section of casing string is milled out with designated tools at the desired depth. The tool is lowered into the wellbore and hydraulic pressure is increased to extend the cutting blades. The tool is rotated and the process of milling is initiated[48].

The milled section needs to be cleaned out by washing the open hole when the desired section is milled. It is important to wash the section to remove swarf and debris. The formation will be exposed and the open-hole section is circulated clean to ensure good bonding between the formation and cement plug.

There are many challenges that can occur during a milling operation. It is a time consuming and complex operation where swarf handling, fluid properties, formation exposure and damaged well control equipment are some of the main considerations[50]:

- *Swarf handling*
- *Sufficient hole cleaning*
- *Open hole exposure*
- *Low milling speed*
- *Vibrations*
- *Wear on mill*
- *Milling of multiple casing strings*

Swarf handling is considered the main challenge with SM. Milling creates metal cuttings, called swarf, and can be stuck as it is transported up to the surface. When cuttings get stuck, referred to as “bird nest”, they can restrict the flow and SM tools can get stuck during retrieval. Swarf will often accumulate in areas with reduced annular velocity, which can be at the liner hanger, BOP and marine riser. Mud will push the swarf towards the surface, which can plug the BOP if present during the milling operation. This prevents the use of critical equipment and can be a safety hazard in case of a kick. It is important to clean the wellbore to remove all swarf and debris, especially in the BOP after milling out a section[48].

It is also possible to mill out several casing strings in one run. If the casing strings are not centralized due to large off sets, the milling operation has to be done carefully. Figure 25 illustrates off set casings in a well.

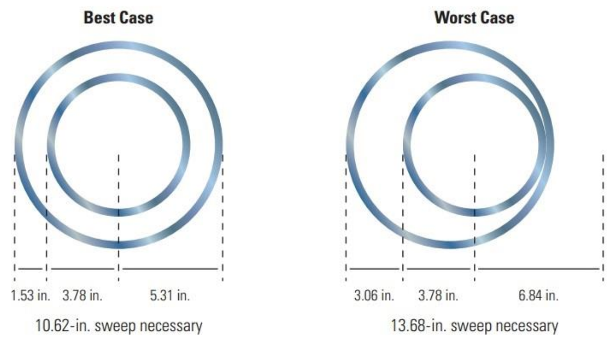

Figure 25: Necessary sweep during section milling of multiple casings[51]

8.3 Perforate, Wash and cement

The perforate, wash and cement system (PWC®) is an alternative to the conventional method of SM. This system perforates and washes the selected casing or liner section before inserting cement into the annuli. By performing such an operation, one will establish a permanent rock-to-rock barrier. The PWC tool, HydraHemera, can wash behind two casings and set one plug in two runs[52].

The tubing-conveyed perforating (TCP) guns (w/HydraKratos) are pulled out of hole after perforation and replaced with the HydraHemera system, which is illustrated in Figure 26. The HydraHemera system consist of a bullnose for circulation in the bottom, the Hemera jetting tool with angled nozzles for washing behind both casings, the Hemera cementing tool and the Archimedes cementing tool for centralization and to squeeze cement into the annuli [53].

It is always wise to conduct a logging run to determine where the best-suited intervals are situated. The best suited interval is where the smallest amount of cement is located or at TOC[53]. After perforating the casing(s) the TCP guns are dropped in a rat hole below the perforations or retrieved if unable to be dropped. The perforated area is washed with the washing tool to remove debris, old mud, old cuttings, barite and cement traces. Once the annular space is washed, the present fluid is displaced by spacer fluid to ensure good bonding and no contamination when inserting cement[53]. Verification of cement has to be done when the cement job is finished. On a field where this technology has not been used before, the operator normally requires that the internal cement plug is drilled out to be verified by logging.

Figure 26: HydraHemera[53]

The HydraKratos can be attached to the bottom of the TCP guns to ensure a solid base for the upcoming annulus cement barrier (external WBE). The HydraKratos ensures casing expansion and casing to formation wall fit [53]. Figure 27 illustrates the result of the job performed by HydraKratos.

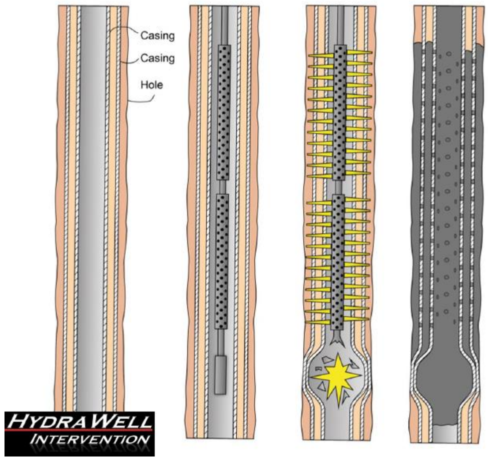

Figure 27: TCP guns w/HydraKratos[53]

8.4 Open Hole Cement Plug

Setting an open hole cement plug is an easy and standard operation. There are two scenarios where an open hole cement plug is installed and comprises:

- *Open-hole formation plug*
  - *Cross-sectional cement plug bonding to the formation*
    - *After SM*
    - *After Cut and pull (if exposed formation behind casing)*
    - *Applies for wells designed as open hole below the production casing*
- *Internal cement plug (ICP)*
  - *Cross-sectional cement plug bonding to the inside of the casing (Requires verified barrier outside of the casing).*

Good cement job planning is required to set a good quality cement plug. The most common method to perform an open-hole cement plug is the balanced method. This method requires a foundation in the well onto which a cement plug can be placed. The foundation is most likely a mechanical plug or a specially designed liquid fluid.

A work string with a cement stinger in the bottom-end is run down the hole to be able to place the cement in the wellbore at the desired depth. A balanced plug can be set by pumping cement slurry through the work string with a spacer fluid in front and behind. The spacer fluid must be compatible with the cement and any other well fluids that might be downhole. The reason for using a spacer fluid is to ensure no contamination when the cement contacts with other fluids that can affect the design properties of the cement. Another reason for using spacer fluid is to clean the pipe in front of the cement and displace all previous liquid in the well[54].

9 Riserless P&A Scenarios

9.1 P&A Challenges of Subsea Wells using a RLWI vessel

Before describing the base cases, one need to address the key challenges of P&A operations using a RLWI vessel. Some of the challenges presented are also regarded as general challenges of P&A operations.

9.1.1 Production Tubing

It is not a requirement that one shall remove the production tubing, but it is usually removed due to the subsequent requirements related to the potential leak paths and upcoming work[55]. The production tubing is normally pressure tested against deep set plug to verify tubing integrity for the upcoming job. If the tubing is leaking, the current practice is to retrieve it.

The position of the permanent WBs are one of the most important factors. If the external cement cannot be verified with good quality cement logs from previous operations, one have to pull the tubing to be able to log the cement behind the production casing. Some operating companies have company specific requirements/guidelines that requires updated cement bond logs, which results in the necessity of pulling the production tubing.

Another reason for pulling the production tubing is the control cables that are attached/clamped along the tubing itself. The position of the permanent WB might be in an area where the control cables are located. These flatpacked control cables consists of hydraulic and electric lines enclosed with a polymeric protection, allowing measurement, control and regulation of downhole equipment. Figure 28 shows a typical control line with two braided wires (increased strength), one hydraulic line and one electric line. The hydraulic line causes problems because the fluid conduit is a potential vertical leak path. There are several solutions of cutting the control line, but there are no field proven solutions for control line removal. DrillWell did a full-scale experiment in 2016 to see the potential of setting a cement plug with tubing and control lines in place. This experiment showed

Figure 28: Control line from the workshop to Island Offshore Subsea

that it was possible to get a good cement job in annulus when the tubing was left in hole. It also showed that the presence of control lines did not represent any additional leakage paths after it was cemented[56]. However, by applying this method offshore one are more prone to cement contamination and a poor cement job due to a longer cement transport. This method is not field-tested and for that reason, one have to pull the production tubing to remove the control lines.

9.1.1.1 Production Tubing Retrieval

To be able to retrieve the production tubing, one need a tool that can be locked into the TH and unlock the TH from the WH or XT. Several tools are suited to retrieve the TH and the tubing itself. However, it all depends on the supplier of the well completion and production system. There are two methods to unlock the TH, i.e. hydraulically and mechanical. The mechanical method requires torque to activate its locking mechanism and is not applicable if recovering the TH with CT or WL, unless it is equipped with hydraulically or electrical driven tools that can rotate and supply enough torque.

During TH installation, one need to orientate the TH regardless of VXT or HXT:

HXT – *An alignment key assures that the side production bore on the TH aligns towards the production bore inside the HXT.*

VXT – *An alignment key enters a key slot in the drilling BOP and the TH is correctly oriented prior to lock it into the WH.*

All fields are using field specific tools and equipment that are designed for their wells. There are three tools that could be applied when retrieving the TH without the use of drill pipe, and both are hydraulically activated;

Tubing hanger emergency release tool (THERT) – *This tool is only used to retrieve the TH and is not accommodated with any seal stabs[3]. It is RIH and hydraulically locked to the tubing hanger running tool (THRT) locking profile inside the TH by increasing the internal pressure. Simultaneously the collet fingers on the THERT locks onto the upper lock mandrel (lock ring*

[3] Seal Stabs: Seals between a tubing hanger running tool or XT and tubing hanger to activate hydraulic functions

actuating sleeve). As the pull is initiated, the upper lock mandrel is retracted until the lock ring on the TH towards the WH/HXT is unseated. We are now free and can pull the TH and production tubing while replacing the displaced fluid[57].

THERT, mechanically operated – *This tool is today used on drill pipe to unlock and retrieve the TH. The tool is RIH and accommodated in the TH with some weight, then it is rotated 3.5 turns to lock onto TH and simultaneously lock the collet fingers to the upper lock mandrel. As the pull is initiated, the outer body of the THERT moves away from the main body to unseat the lock ring towards the WH/HXT. The outer body stops in some profiles in the main body, subsequently the TH and production tubing can be pulled[57]. It will require an additional component that can rotate If using this tool without drill pipe.*

Tubing hanger running tool (THRT) – *This tool is normally used for TH installation, but can also be used to retrieve the TH. Because it has seal stabs, it will require orientation if the well is completed with a VXT. If the well has conducted phase 0, one is not dependent on seal stabs ensuring separate hydraulic communication to main bore and annulus. One solution is to remove the seal stabs and regardless of orientation, one lock onto the TH and unlock the TH from the WH. Its retrieval method is almost the same as for the THERT. However, there are several hydraulic lines, connected to the hydraulic connectors on top of the THRT, which engage and disengage the lock and unlock functions. When the TH is unlocked from the WH/HXT the TH and production tubing can be pulled while replacing the displaced fluid. To make it clear, if using this tool the seal stabs would have to be removed in order to avoid orientation. The THRT is more of an installation tool and is not design to withstand the same loads, i.e. approximately 50 % reduction in pulling capacity[58].*

Tubing hanger running and orientation tool (THROT) – *This tool is used to install the TH and tubing. The reason is that it has an orientation system that allows for annulus and tubing bore access with its 2” annulus bore and 5” tubing bore. This tool is not included in this thesis to retrieve TH and tubing, but to allow for annulus and tubing bore access to run wireline in order to retrieve annulus and tubing hanger plugs. It has a key slot that matches the orientation pin in the SSD to ensure correct orientation when installing it on top of TH[57].*

The THRT/THERT can be run on the main winch in the module handling tower (MHT), which on the Island Constructor is limited to 200 ton safe working load (SWL) pulling capacity. A subsea jacking unit can be used as a contingency in case the tubing and the overpull exceeds the safe working load (SWL). This should be decided in the initial phase of the operation. Between the THRT/THERT and main winch, one must have an assembly, landing string, consisting of a lifting sub, hydraulic connections, pup joint and x-over to tool. As the tubing is going to be retrieved, the Subsea shutoff device (SSD) must be used during this operation. The reason for that is to accommodate the tools and subsequently the tubing. The SSD has an ID of 18 ¾" and shall provide a safe retrieval operation. One consideration must be taken when rigging up the assembly; Since the SSD will be used during this operation, one must assure the correct space out prior to seal around the landing string with the annular preventer. The landing string itself must also be long enough to be able to mount a jacking unit above the SSD. Since we are using hydraulically activated THRT or THERT, one does not require any fixed orientation to the TH (seal stabs removed on THRT). Nevertheless, the mechanical THERT needs rotation to be activated and a subsea thong above the SSD or subsea jacking unit is most likely needed.

The THRT and THERT are conventional tools, but one problem is that the landing string will have to be developed. Every part on the landing string, except the thick walled pup joint with predrilled holes and treads to transport hydraulic fluids, exists on the marked. It would not be a comprehensive nor expensive development and should be possible. The hydraulically THRT and THERT in Figure 29 is a self-made landing string and will be used in my upcoming base cases.

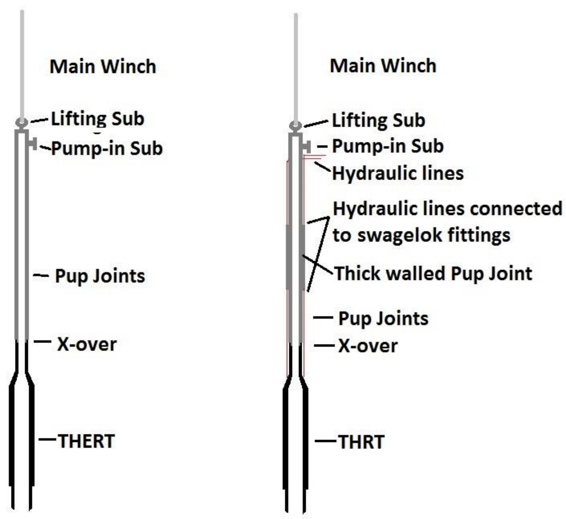

Figure 29: Hydraulically THRT & THERT w/proposed assembly

9.1.2 Verify Good Quality Cement Behind Casing-strings

Prior to set an internal WB in the casing string, one have to evaluate and ensure that the external WBE (i.e. annulus cement) consist of good quality cement and provides the required length. A great number of subsea wells were not logged during its construction due to the priority of saving money by reducing the time of operation. Today there are two options; use the existing cement bond logs (CBL) for that specific well or run a new CBL.

Bond logs are run to determine the[39];

- *cement to casing bonding*
- *cement to formation bonding*
- *Evaluation of cement conditions*
    - *Channeling*
    - *Compromised cement (i.e. gas cut, dehydrated, etc.)*
    - *TOC*
    - *Microannulus*

This is not a technical introduction to the different CBL tools and how it work. But rather an emphasis of the importance of qualifying external WBs and the consequences of not having logged the exterior.

If the primary –or secondary WB is to be set in the production casing, one have to examine previous CBL to see where there is sufficient length (min. 30m MD) with good cement to act as an external WBE before installing an internal WBE. In cases where the external WBE is unverified, one must perform a logging run. If the production tubing is in place, this will have to be retrieved at this stage in order log behind the production casing. Since there are no logging tools that can log through more than one casing string, we might end up cutting and pulling several casing strings prior to log and confirm external WBE during a P&A operation.

9.1.2.1 Annulus Barrier Establishment

Old wells were not designed with respect to P&A and although the casings in the well where cemented at the position for the upcoming P&A job, the cement job could be of poor quality.

The establishment of annular barriers will commence after phase 0 and will be a part of phase 1 and 2.

A-annulus is never cemented during well completion, but could be cemented when establishing permanent WBs in a P&A operation, e.g. Production tubing left in place. The prerequisite is that the external cement on the production casing/liner has good quality cement verified by former cement bond logs. The conventional method is to retrieve the production tubing in phase 1.

If installing a permanent WB at a depth where the B –and C-annulus are not logged or have no cement, the tubing has to be retrieved. In addition, one might have to do a remedial cement job, section milling or cut and pull casing strings. Since the P&A operation will be performed from a RLWI vessel, one would try to avoid doing section milling or/and cut and pull of casing strings. The remedial cement job embraces the establishment of good quality cement in B –and C-annulus, which together with an internal permanent WB creates a WB envelope in the entire cross section. There are different technologies and methods to establish annulus barriers and a common issue is that they are all time consuming.

9.1.3 Cut and Pull Casing Strings

A description of why one have to cut and pull casing strings is given in chapter 8, but technical challenges related to this operation is not thoroughly disclosed. Regardless of unit performing PP&A, cut and pull of casing strings are to be avoided if possible. Companies could reduce their expenditures if the subsea well could be PP&A without retrieving any steel tubulars. However, many wells will have to retrieve/remove casing strings prior to establishing an annular barrier or to perform a CBL ensuring good quality cement.

Both intermediate casings and the production casing have a casing hanger that are hung off inside the subsea WH. The casing hanger's OD is almost equal to the ID of the WH. Regardless of this tight fit, a casing hanger seal assembly must be installed to lock the casing hanger and to seal off vertically.

If parts of the production casing have to be cut and pulled, one have unlock and retrieve the casing hanger seal assembly prior to retrieving the casing hanger and casing. A casing hanger seal assembly retrieval tool is used to latch into the seal assembly. By applying a straight vertical pull, the seal assembly unlocks from the casing hanger and subsea WH. A pull spear can be used to lock into the casing/casing hanger and retrieve it to surface. Some types of casing hanger seal assemblies requires rotation to be retrieved and will require additional equipment to enable rotation.

As mentioned in chapter 8, the pulling force can be of great numbers due to external materials that exert high frictional forces. By assuming that the casing is free to be pulled, one have to consider other elements that cause friction and thus a higher pulling force:

- *Corrosion on casing hanger or inside the WH, resulting in a restriction when pulling the casing hanger out of the WH or/and requires high over pull to release it.*
- *Asymmetric pull (i.e. not vertical) increases the pulling force (Vessel drift off)*
- *Might be some small frictional forces due to the closed annular preventer*
- *High dogleg severity and deviated wellbore trajectory could increase the frictional force.*

9.1.4 Establish Open Hole to Surface Plug

The open hole to surface plug is the last barrier towards the environment and is set to avoid shallow inflows. This is more of an environmental WB and it has no depth requirements with respect to formation integrity. This surface plug generates a lot of extra work because it typically requires the tubing to be retrieved. The reason for that one typically have to cut and pull the 9⅝" and the 13⅜" casing to get access to the 20" casing.

It is common that the 9⅝" production casing and 13⅜" intermediate casing have no cement at the setting depth of the surface plug. One typically have to establish external barriers in B – and C annulus. The scope of work depends on whether the casing or casings have been removed prior to set primary and secondary WB. Hence, depending on the case, one, two or no annuli have to be cemented to make sure that the surface barrier seals horizontally.

There are several scenarios and all of them requires a good cement job planning and execution in order to provide sufficient integrity. Well abandonment straddle packer (WASP), Suspended well abandonment tool (SWAT) and cementing adaptor tool (CAT) are all designed to establish an open hole to surface barrier from a RLWI vessel.

9.1.4.1 Well Abandonment Straddle Packer - WASP

This tool from Baker Hughes is used without a riser and run on wireline, thus providing less deployment time. It is deployed from a vessel and lands and seats in the high pressure wellhead. In a single trip, it provides isolation and allows for perforating, circulating out old mud from behind the casing strings, and placement of external (across casing annuli) and internal cement plug. It is designed to cement two annuli in one trip[59].

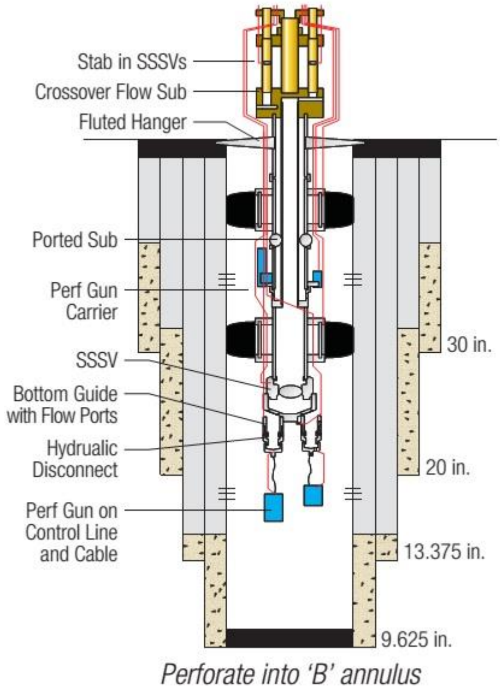

Figure 30: WASP tool from Baker Hughes [60]

The system is accommodated with two separate inflatable packers for isolation and to allow circulation and fluid returns. It also has two pairs of selective perforation guns to establish the first and second annulus cement in two sequences. There are three tubing-retrievable subsea safety valves to aid securing the well if emergency shut-in is required. Hence, it can disconnect and leave the tool in case of emergency.

Operational sequence: Deploy tool and inflate packers towards casing. Pressure test to confirm pressure integrity. Perforate casing with lower and upper perforation gun and circulate annulus between production and intermediate casing with clean up pill prior to set cement. When the cement has set, perforate through production casing, cement and intermediate casing with the second upper and lower perforation guns prior to circulate and cement in the outer annulus. The cement is placed both external and internal in the last stage[60]. Wait on cement and pressure test to 500 psi[4].

9.1.4.2 Suspended Well Abandonment Tool - SWAT

The SWAT tool from Claxton engineering is also used to establish an open hole to surface plug on subsea wells by using a RLWI vessel and wireline. SWAT was the first abandonment tool to establish a surface plug and it was introduced on the UK sector in 1996[61].

SWAT and WASP are two tools that provide the same result and are run in the same way. The operational sequence of the SWAT tool is equal to the WASP. Both tools are served with an umbilical on top the tool to allow fluid injection and return.

This tool are mainly used on exploration wells and has little experience on production wells[62].

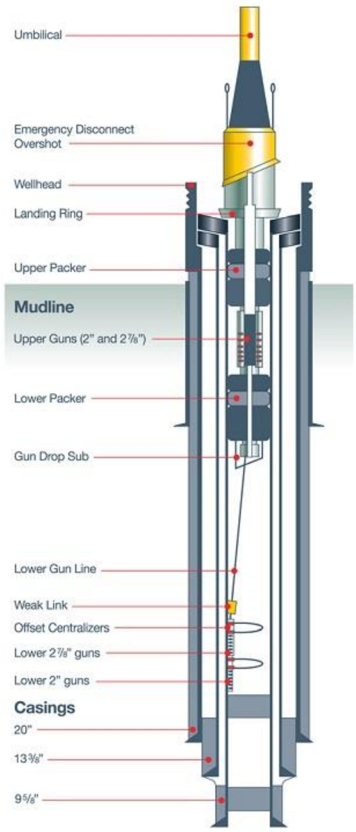

Figure 31: SWAT tool from Claxton Engineering [61]

9.1.4.3 Cementing Adaptor Tool – CAT

The CAT tool can be used to establish the open hole to surface barrier, but it can also be applied to install the primary – and secondary WB. As the previous described tools, this tool can also be used to set a WB in one or two annuli. This tool can be run together with the RLWI stack, providing full well control in case of hydrocarbon influx or pressure build-up. The CAT is still under development and its design could change before being approved and introduced to the marked.

The CAT tool consist of a cement adaptor spool and a cement stinger. The cement adaptor spool is installed on top of WH or HXT. The cement stinger is run inside the well control equipment prior to be landed and locked into the cement adaptor spool. The cement stinger have two setups. Either it can be accommodated with a packer to seal towards the casing prior to circulate cleanup pills and cement (open hole to surface plug), or it can be accommodated with wiper plugs that transport the calculated volume of cement to be set in annulus and inside casing (primary and/or secondary WB).

The casing or casings are perforated in a separate WL run, allowing selective perforation to establish lower and upper annulus communication ports. The perforations also provides a circulation route for annulus cleaning, and displacement and spotting of competent cement[16].

Operational sequence (Open Hole to Surface Plug): The adaptor and RLWI stack are installed on top of WH in one run. Wireline with perforation gun is lubricated into the well and perforates the upper and lower perforations. The cement stinger is run in hole and locked into the cement adaptor spool as illustrated in Figure 32. Its packer is hydraulically set towards the casing wall prior to circulate clean the main bore and annulus before cement is installed. If there are more than one annulus, an extra wireline run is necessary in order to perforate and then circulate and cement the new exposed annulus. The internal plug is placed on top of a foundation. The cement is pressure tested after it has set, then the packer is released and the adaptor and RLWI stack is retrieved[10].

Figure 32 is an example of how to establish an open hole to surface barrier with only one annulus to be cemented.

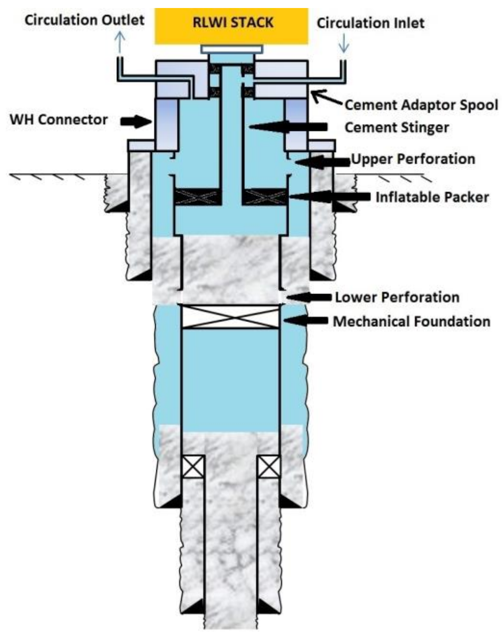

Figure 32: Illustration of an open hole to surface plug establishment[10]

Note that this cement stinger can be fitted with wiper plugs, illustrated in Figure 33, to allow the installation of primary and/or secondary WB. These wiper plugs, activated by dropping two separate balls, are applied to avoid contamination of cement during its transport.

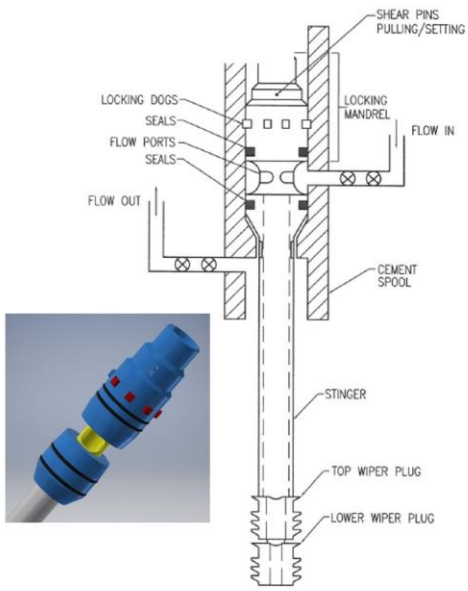

Figure 33: CAT accommodated with wiper plugs. Lock mandrel is also illustrated [10].

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10 Overview of the Proposed Systems

Well integrity management is a key factor to successfully establish all permanent WB in a safe and prudent manner during the P&A operation. It is crucial to have knowledge of the WBE, WB and WB envelopes in order to avoid any accidents during an operation. The current applications regarding P&A operations from RLWI vessels are described in previous chapters. However, today's application is mainly limited to wireline operations and fluid circulation.

During a P&A operation CT could be applied to enable the installation of e.g. an internal WB consisting of good quality cement. The RLCT stack is a new stack that shall provide well control and the ability to use both CT and WL. The main components when using the RLCT stack consist of the WCP (connected to WH or HXT), LLP, ULP and CTH (subsea strippers and SSI). If the next step is to run in with wireline, the CTH is retrieved together with the CT bottom hole assembly prior to run PCH together with the wireline.

Here are the proposed well control rig ups:

- *RLWI stack – XT/WH*
- *RLWI stack – CAT – XT/WH*
- *RLWI stack - SSD – (CAT) – XT/WH*
- *RLCT Stack – XT/WH*
- *RLCT stack – CAT – XT/WH*
- *RLCT stack – SSD – (CAT) – XT/WH*
- *RLCT stack (without WCP) – SSD – (CAT) – XT/WH*
- *SSD – (CAT) – WH/XT*

Table 4 illustrates the RLWI vessels current applications as it is conducted on the NCS today. Some subsea wells are complex, but the purpose is to conduct all P&A phases from a RLWI vessel by combining WL, CT and main winch. By introducing CT, the scope of work from RLWI vessels increases. The placement and quality of cement increases as we transport the cement through a clean string with no unknown restrictions and uncontaminated fluid. In addition, the PWC® tool, HydraHemera, from Hydrawell can be run on CT. Hence, cut & pull of casing strings could be eliminated or reduced in phase 1 and 2.

The green squares illustrates the experience and that this operation is classified as a standard operation. The yellow squares illustrates the upcoming technology and equipment that shall allow a RLWI vessel to conduct that specific phase. The red squares illustrates the current situation, illustrating no experience nor provided technology to conduct that phase.

Activity	RLWI Vessel	
	Present	Future
Phase 0 - Preparatory Work for P&A	RLWI Stack	RLCT Stack
P&A Phase 1 - Reservoir Abandonment		RLCT Stack and SSD
P&A Phase 2 - Intermediate Abandonment		RLCT Stack and SSD
P&A Phase 3 - Wellhead and Conductor Removal	Wireline cutting tool. WH & Conductor retrieved on winch	Wireline cutting tool. WH & Conductor retrieved on winch

Table 4: Existing vs. Proposed Applications of a RLWI Vessel

11 Riserless P&A Operations – Base Cases

As there are several methods of how to perform PP&A and each well has its own characteristics, it is hard to make a general description of a P&A operation. In this chapter, some different approaches of a riserless P&A operation conducted from a RLWI vessel will be discussed. There are thousands of wells on the NCS and worldwide, all with different well designs, field specific problems e.g. subduction, unconsolidated formations, material degradation and old wells with poor documentation.

Making a P&A base case covering all methods and technologies is impossible. For that reason, several base cases will be discussed and illustrated to give the reader an overview of possible approaches to conduct riserless P&A operations from a RLWI vessel. The technology gaps and challenges should be revealed once analyzing the upcoming base cases. The following operational sequences is a proposal and are based on the presented technologies and methods within P&A, and then combined with the RLWI vessels current and upcoming applications to perform well activities.

All the upcoming base cases have a column in the operational sequence table where each step of the P&A operation is categorized and defines the well abandonment complexity. The purpose of introducing this categorization is to highlight the complexity of the operation. If the RLWI vessel can perform type 4 work, the abandonment complexity would have to be re-defined, as it states that this type of work is complex rig-based.

11.1 Well A – Tubing left in place

This fictional well is created as a perfect candidate, i.e. a simple production well to be PP&A. Since it is a simple well, the limitations will be prevailed during the presentation of the operational sequence. The production tubing is left in place, but it has to be cut at shallow depth and pulled in order to establish the open hole to surface plug. The RLWI stack used during the P&A operation is the existing stack used on Island Constructor today (NB! Valves on stack illustrated in the WBS may be different, but that does not affect the operation).

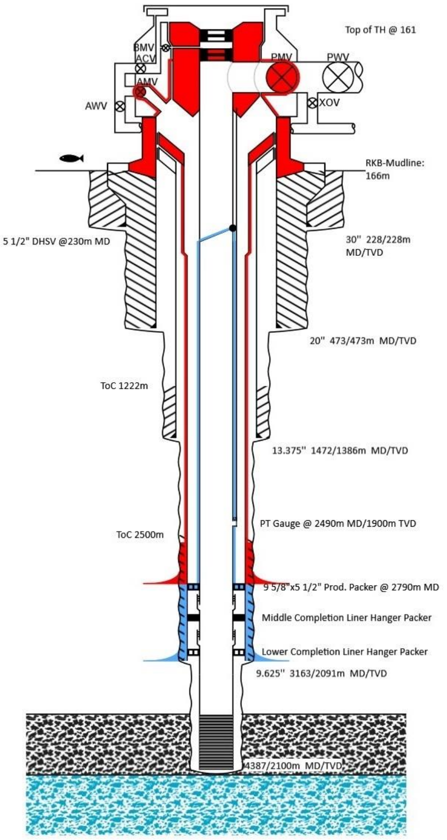
11.1.1 Well A Specification

Well A is a closed single satellite oil production well with natural water drive and a current reservoir pressure of 200 bar. Shut-in WH pressure (SIWHP) were measured to 40 bar and future anticipated reservoir pressure is assumed to be 300 bar. HXT is tied up to host platform with production flowline. All WBE's are good or have negligible issues. This base case is does not require full production tubing retrieval because the pressure/temperature (PT) gauge are located 300m MD above the production packer. Hence, there is sufficient length to place the primary – and secondary WB. Figure 34 is an illustration of the wellbore and supplements with more specifications.

A formation integrity test (FIT) performed at 2091m TVD when drilling the well was measured to 1.6 sg. By calculating the minimum setting depth by using the specific gravity of the oil (0.76 sg) the setting depth becomes approximately 1750m TVD. A more conservative method is to use the specific gravity of gas, which gives a minimum setting depth of 1870m TVD. To ensure that the permanent WB installed in the well can withstand future anticipated pressure regardless of formation fluid, the base of the secondary WB will be set at 2450m MD (approximately 2000m TVD). The deviation at packer setting depth is approximately 50˚ and does not require a well tractor.

Field : Base Case
Well : A
Schematic : US.H 4.1-a1 rev. 1
Date : 28.Apr.2017

Well design pressure 220 Bar
Reservoir pressure 200 Bar
Prepared By : Thomas Øia



Depth reference is RKB Island Constructor
Depth correlation None

Producer

Closed Production Well

Draft

Primary barrier elements

Element	Qualification	Monitoring
Downhole Safety Valve	Pressure test to 70 bar (Differential)	Periodic leak testing
Tubing	Pressure test to xxx bar	A-annulus pressure
Production packer	Pressure test to xxx bar	A-annulus pressure
Production casing	Pressure test to xxx bar	N/A after initial verification
Production casing cement	Formation test, Good cement verified by CBL	N/A after initial verification
Formation (in-situ)	Quote test or prognosis strength	N/A after initial verification

Secondary barrier elements

Element	Qualification	Monitoring
Subsea production tree	Pressure test to xxx bar	Downstream pressure
Crown plug	Inflow- or pressure test from above to xxx bar	Pressure above plug
Tubing hanger	Pressure test to xxx bar	Periodic leak testing and continuous pressure monitoring of A-annulus
Wellhead	Pressure test to xxx bar	Periodic leak testing
Casing hanger	Pressure test to xxx bar	A-annulus pressure
Production casing	Pressure test to xxx bar	A-annulus pressure
Production casing cement	Formation test, job performance or bond log	N/A after initial verification
Formation (in-situ)	Quote test or prognosis strength	N/A after initial verification

Healthy well, no or minor issue

Note:
Horizontal reservoir section

Figure 34: WBS of Production well

11.1.2 Operational Sequence

Well A		
Pre-Assumptions	1	Cement log performed during initial completion
	2	Cement is assumed to be good on all casing sizes
	3	No sources of inflow, formation with normal pressure or over-pressured/impermeable formation in the overburden formation
Standard Operation	4	
Technology Provided, Little or no Experience	5	
Technology Not Provided	6	

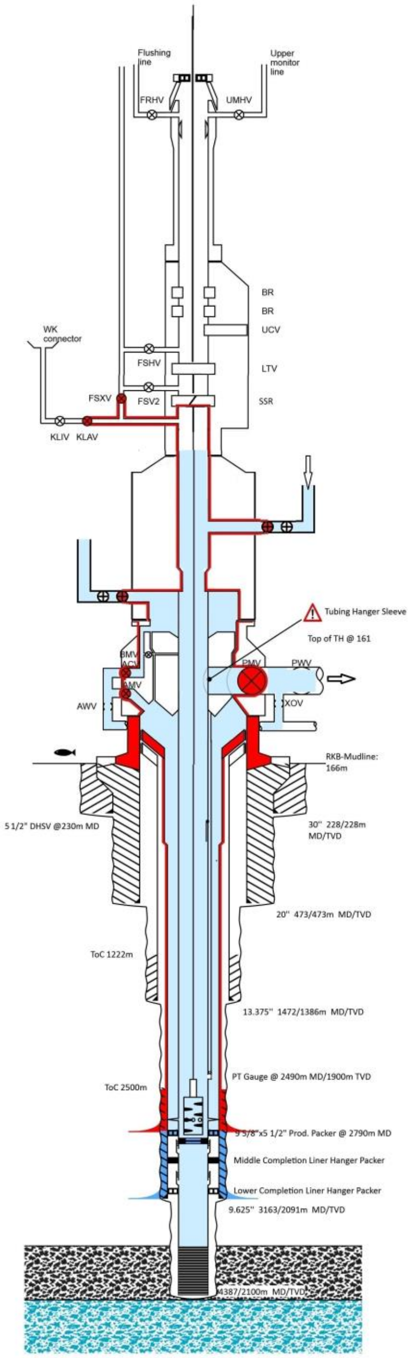
Seq. No.	WBS	Description	Comment/Reference	Abandonment Complexity (Type)
1	x	Arrive 500m zone, DP trial		1
Preparatoy Phase				
2	1	Recover tree cap and clean re-entry hub	WL	1
3	1	Install RLWI stack on top of HXT	A cement Spool is installed below the WCP (at the bottom of the RLWI stack) and completed with circulation hoses.	1
4	1	Retrieve upper crown plug on WL		1
5	1	Retrieve lower crown/tubing hanger plug on WL		1
6	1	Kill well, bullhead	30/70% MEG and Seawater or Brine could be used	1
7	1	Drift run w/caliper log or mechanical	Ensuring no obstacles/large enough OD for the upcoming tools	1
8	1	Install deep set plug @2800m MD (inside tailpipe) and pressure test plug	If BR plug (non-return valve) is used, it can only be tested up to a preset pressure. If tubing is leaking, the alternative method is to use CT to install the primary and secondary WB or retrieve the production tubing prior to set an internal cement plug in 9 5/8"	1
9	1	Run TH Sleeve	TH sleeve must be set to block of TH side outlet for coming cement job	1
10	1	Punch/perforate tubing	Above production packer. Pressure/temperature log can be integrated in this run. Not always necessary, due to provided information. These parameters are used in the cement job planning.	1
11	1	Circulate annulus (down prod. Tubing and up annulus)	30/70% MEG and Seawater or Brine, returns sent to online host facilities through production flowline.	1
Reservoir Abandonment				
12	2	Set cement spool isolation plug	Set to isolate the RLWI stack from fouling by cement	1
13	2	Pump and sqeeze (through punched/perf. Holes) min 100m good cement plug down prod. Tubing and into A-annulus (**primary and secondary cement plugs**, adjacent to/overlap annulus cement behind 9⅝"),	A-annulus is closed until front wiper foam balls lands and seals off BR plug, i.e. fluid volume in tubing is bullheaded into the reservoir section until wiper foam balls lands in BR plug and annulus valve is opened. Continue pumping as per volume calculation until tail wiper is at same height as TOC in A-annulus. Turbulent flow may occur if the passage to A-annulus is to small, resulting in a contaminated/poor cement job.	1
14	3	Pull cement spool isolation plug		1
15	3	WOC	Whilst a minimum setting time is an operational requirement, excessive setting times are to be avoided	1
16	3	Pressure test cement plug	To verify integrity of plug	1
17	3	Tag TOC	To verify TOC is as per cement programme	1
18	3	Pull RLWI stack	Together with the cement adaptor spool and WCP	1
19	3	RIH with mechanical cutter on E-line, and cut 5.5" tubing 100m below WH	below DHSV	1
20	x	Retrieve mech cutter		1
Alternative 1				
21	4	Retrieve HXT and 100m of production tubing on main winch	Before removing well control equipment, one must monitor A-annulus pressure to ensure no pressure build-up.	3
22	x	Close Moonpool door and skidd a parking frame below HXT.	HXT rests on parking frame prior to set slips in false rotary table and to cut prod. Tubing in order to remove the HXT from drill floor.	1
23	x	Set slips in false rotary table and hydraullically lower the parking frame to ensure tubing is landed out in slips	To prevent prod. Tubing from falling down to seabed	1

24	x	Cut prod. Tubing below HXT			1
25	x	Skidd parking frame w/HXT to storage location on deck	Parking slot on barbor side between derrick and hangar		1
26	x	Lift tubing on main winch with an internal or external gripping tool	Mechanical or hydraulically activated tool.		1
27	x	Set tubing in slips			1
28	x	Cut tubing	Shear tubing above coupling prior to use the manual elevator to grip below the coupling		1
29	x	Lay down tubing			1
30	x	Repeat sequence as above until all tubing is recovered			1
Alternative 2					
20	5	Pick up the hydraulical THERT assembly c/w umbilical. (run on main winch)	Although the THERT is an existing tool , the landing string must be developed in order to perform this job on main winch		1
21	5	Run THERT into HXT	SSD would be installed if lack of two permanent WB		1
22	5	Slack off on main winch			1
23	5	Function THERT - latch to TH			3
24	5	Function THERT - unlock TH from XT			3
25	5	Retrieve prod. Tubing and THERT (w/assembly) on main winch			3
26	x	Set tubing in slips			3
27	x	Unlock THERT and lay down			3
28	x	Make up TH Handling Tool, pick up hanger and reset slips	Any LSA/NORM issues will be adressed by the vessels standard operating procedures.		3
29	x	Using tubing shear - shear tubing above coupling	Rather than spend time backing out the tubing joints it is proposed to utilize an "off the shelf" hydraulic tubing shear ("hands free" and remotely operated) to cut the tubing. Also it is proposed to cut the tubing with the control cables and gauge cable in situ - no manual intervention to remove clamps and spool the line and cable.		3
30	x	Lay down tubing hanger			3
31	x	Pick up on main winch and recover tubing			3
32	x	Set tubing in slips			3
33	x	Using tubing shear - shear tubing above			3
34	x	Lay down tubing hanger			3
35	x	Repeat sequence as above until all tubing is recovered			3
36	x	Pull HXT			1
Intermediate Abandonment					
37	6	Install mechanical plug in 10¾" (above transition to 9⅝") with WL	A mechanical foundation should be installed as close to the tubing cut as possible. Production casing is 10¾" down to DHSV and 9⅝" below		1
38	6	Install RLWI stack onto WH	Installed with cement adaptor spool		1
39	6	RIH perforation guns			1
40	6	Perforate 10¾" (lower perf) on WL	Monitor pressure (bleed or feed as required)		1
41	6	Perforate 10¾" (upper perf) on WL			1
42	6	POOH perforation guns			1
43	7	Set CAT stinger and inflate packer			1
44	7	Circulate annulus (10¾"x13⅜") clean and inject a high viscosity fluid			1
45	7	Pump cement into annulus	High viscosity/desity fluid behind cement to to avoid cement returns from annulus to main bore. Monitor pressure (bleed or feed)		1
46	7	WOC			1

47	7	Pressure test	If required by company		1
48	x	Deflate packer and recover CAT stinger			1
49	x	RIH perforation guns			1
50	x	Perforate 13⅜" (lower perf) on WL	Not illustrated in WBS, but same as WBS 6.		1
51	x	Perforate 13⅜" (upper perf) on WL			1
52	x	POOH perforation guns			1
53	8	Set CAT stinger and inflate packer			1
54	8	Circulate annulus (13⅜"x20") clean and inject a high viscosity fluid			1
55	8	Pump cement into annulus and main bore (balanced plug)	Pump slowly to avoid contamination.		1
56	8	WOC			1
57	8	Pressure test			1
58	x	Deflate packer and recover CAT stinger			1
59	x	Pull RLWI stack			1
60	x	Tag TOC	If required by company		1
Wellhead and Conductor Removal					
61	9	Cut and retrieve WH and conductor	WL (cut) and main winch (retrieve)		1
62	x	ROV survey after operation			1

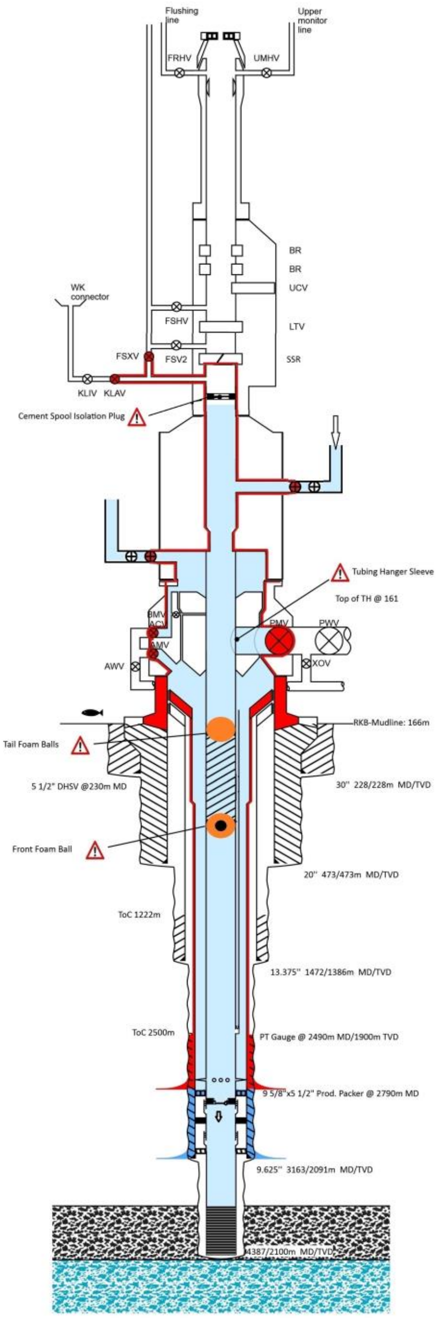
11.1.3 Well Barrier Schematics

WBS: 1



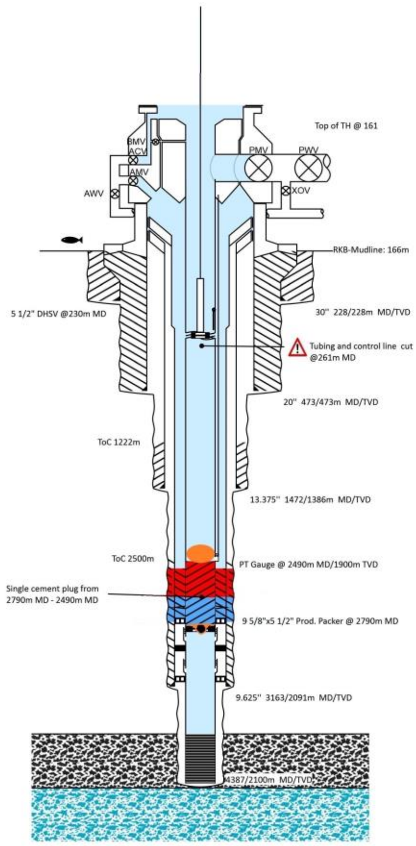
Sequence 2-11

WBS: 2



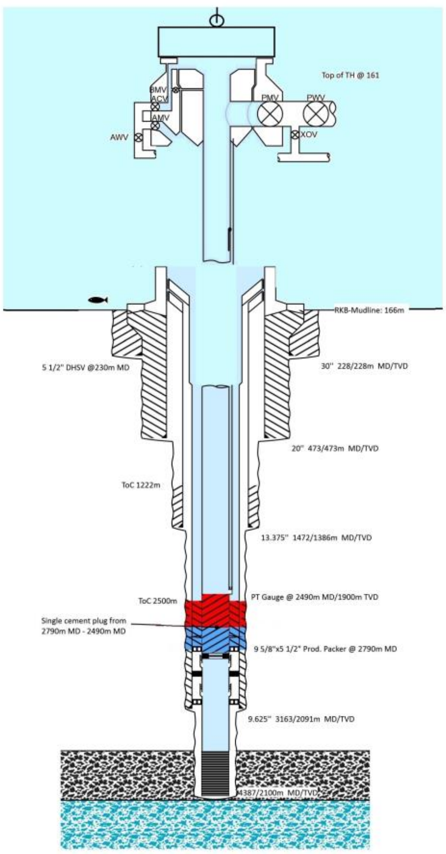
Sequence 12-13

WBS: 3



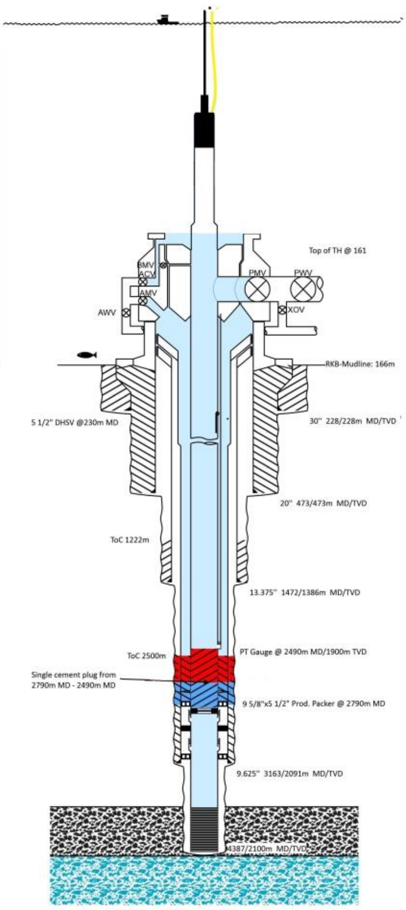
Sequence 14-19

WBS: 4



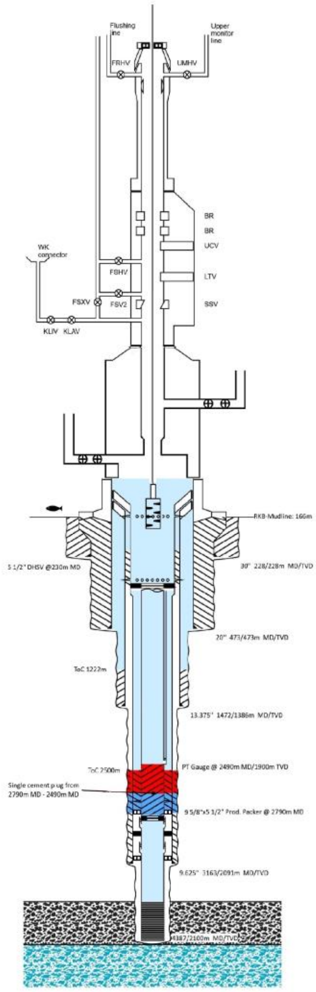
Alternative 1: Sequence 21

WBS: 5



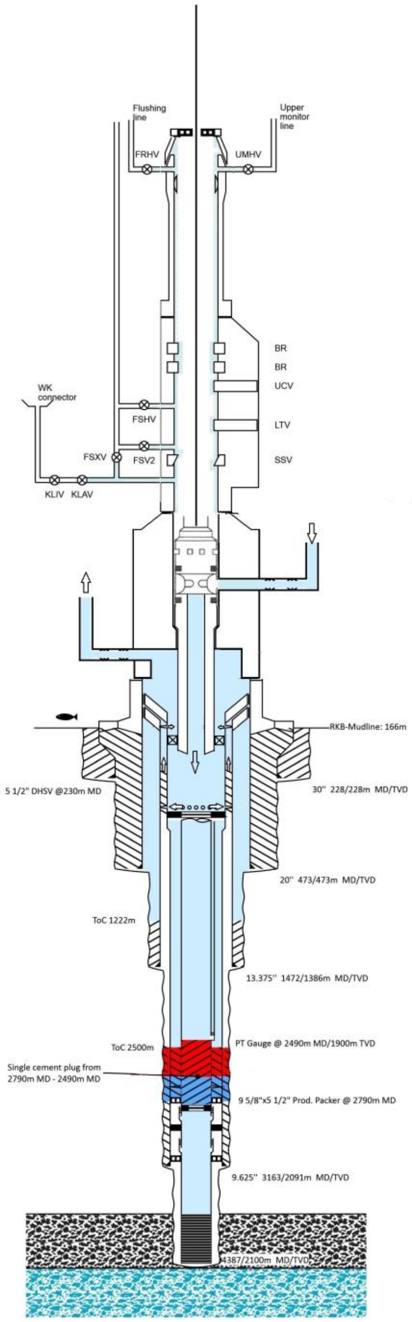
Alternative 2: Sequence 20-25

WBS: 6



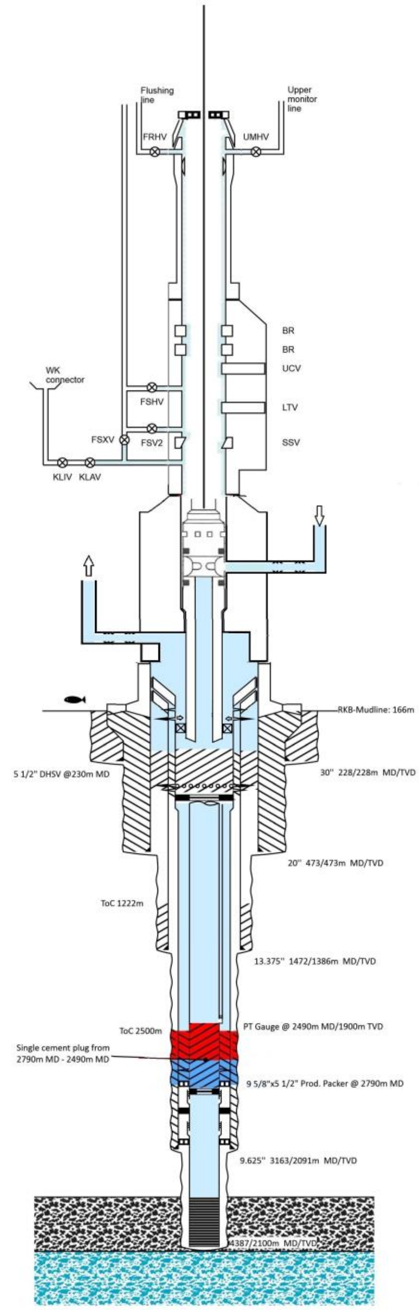
Sequence 37-42

WBS: 7



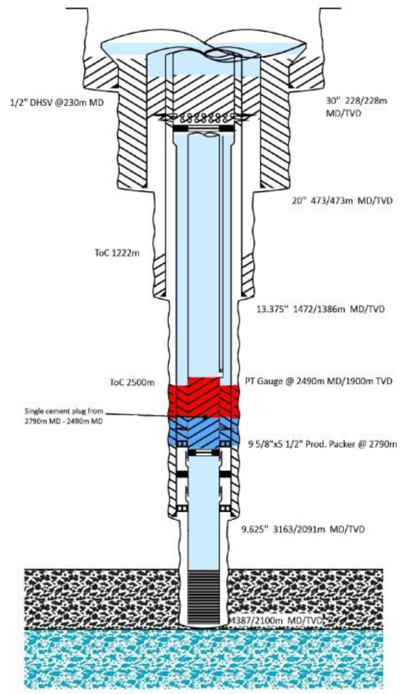
Sequence 43-47

WBS: 8



Sequence 53-57

WBS: 9



Sequence 61

11.2 Well B – Pull production tubing

This well is more complex than the previous one and therefore it will require another methodology to ensure a safe and adequate PP&A operation. A pump-in cap is introduced in this base case to allow greater flow rate during the circulation of A-annulus and main bore. The pump-in cap is connected to top of WCP and it is accommodated with a pump-in valve. The Pump-in cap is added in this base case to illustrate another pumping application. However, it might be sufficient to use the RLCT stack without applying the pump-in cap in most circulation jobs.

11.2.1 Well B Specification

Well B is a closed oil producer with natural pressure support from the gas cap above. There are no other sources of inflow in the overburden. Current reservoir pressure is 250 bar and future reservoir pressure is estimated to initial reservoir pressure, which were 350 bar. SIWHP were measured to 50 bar. It is a single satellite well completed with a VXT and the production flowline to the production facilities is offline. A PT gauge is installed 15m MD/TVD above the production packer. Hence, the production tubing will have to be retrieved. There is an uncertainty of top of cement (TOC) and cement bonding quality in B – annulus. This uncertainty is another reason for pulling the production tubing prior to log behind the production casing. Since the production tubing is completed with a polished bore receptacle (PBR) it allows the upper completion (prod. Tubing) to be pulled without cutting the tubing.

Let us assume that the formation strength in the overburden is insufficient to withstand the future anticipated pressure. NORSOK D-010 states that the primary – and secondary permanent WB must therefore be set as close to the reservoir as possible (i.e in the cap rock)[4]. Hence, 1850m of production tubing will have to be recovered.

11.2.2 Operational Sequence

Well B

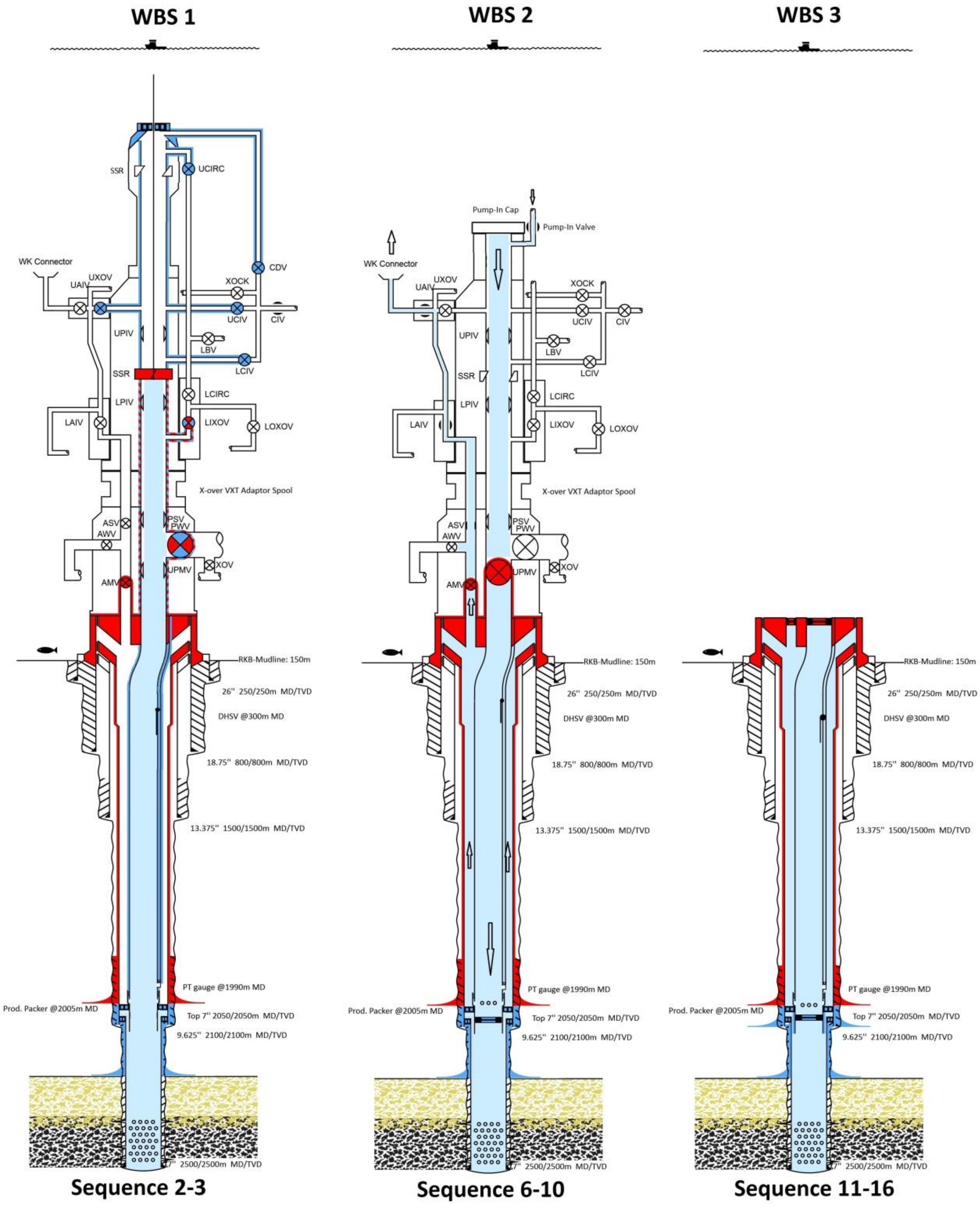
Pre-Assumptions	No.	
	1	No cement logs available/poor cement
	2	One Reservoir section
	3	No sources of inflow, formation with normal pressure or over-pressured/impermeable formation in the overburden formation
	4	
	5	
Standard Operation	6	
Technology Provided, Little or no Experience		
Technology Not Provided		

Seq. No.	WBS	Description	Comment/Reference	Abandonment Complexity (Type)
1	x	Arrive 500m zone, DP trial		
Preparatoy Phase				
2	1	Recover tree cap	WL	1
3	1	Install RLCT stack onto VXT	Installed prior to run WL and CT. Kill hoses installed	1
4	x	Kill well, bullhead	30/70% MEG and Seawater or Brine could be used.	1
5	x	Drift run w/caliper log or mechanical	If required. Ensuring no obstacles/large enough OD for the	1
6	2	Install deep set plug @2010m MD (tailpipe) and pressure test plug	WL operation (PCH on RLCT stack)	1
7	2	Punch tubing	Above production packer. Pressure/temperatur log can be integrated in this run. Not always necessary, due to provided information. These parameters are used in the cement job planning.	1
8	2	Pull Upper Lubricator Package (ULP)	Pulled after PCH has been Recovered.	1
9	2	Install Pump-in Cap on top of WCP	Installed to allow greater circulation into main bore.	1
10	2	Circulate annulus out through A-annulus valve	30/70% MEG and Seawater or Brine, returns sent to vessel.	1
11	3	Pull Pump-in Cap		1
12	3	Install ULP		1
13	3	Install downhole safety valve protection sleeve	WL (PCH). Keeps the valve open	1
14	3	Install tubing hanger plug in main and annulus bore	WL (PCH). May require an extra run to change the x-over adaptor spool	1
15	3	Pull RLCT Stack		1
16	3	Pull VXT to surface		1
Reservoir Abandonment				
17	4	Install SSD with open water mud recovery system	The open water/riserless mud recovery system with its volume control device ensures that the hydrostatic column remains constant. This system is also used to assist fluid returns up to vessel and to avoid oil spill to sea.	1
18	4	RIH THROT on main winch	Prior to retrieve plugs	1
19	4	Retrieve tubing hanger plug in main and annulus bore	Plugs are retrieved on WL. A ROV assist WL tool to enter annulus or tubing bore	1
20	4	POOH THROT on main winch		1
21	5	Pick up THERT assembly c/w umbilical. (run on main winch)	Although the THERT is an existing tool , the landing string must be developed in order to perform this job on main winch	3
22	5	Run THERT		3
23	5	Slack off on main winch		3
24	5	Function THERT - latch to TH	Might require sufficient weight to connect. Can be adjusted with heavy drill collars. If not sufficient, we must use a subsea jacking unit to supply with push/pull force.	3
25	5	Close annular onto slick joint on THERT landing string (stripping pressure only)		3
26	5	Function THERT - unlock TH from XT and subsequently pull TH and tubing to unseat TH	Monitor pressure and circulate out residual well fluid retained under tubing hanger prior to open annular. **Contingency:** Lifting (unseat) the tubing hanger and 2000m tubing typically requires overpull. Main winch is limited to 200 ton and can be a show stopper. A subsea jacking unit should then be applied to overcome the static forces	3
27	x	Open annular and pick up on main winch to recover THERT and 1850m tubing		3
28	x	Set tubing in slips		3

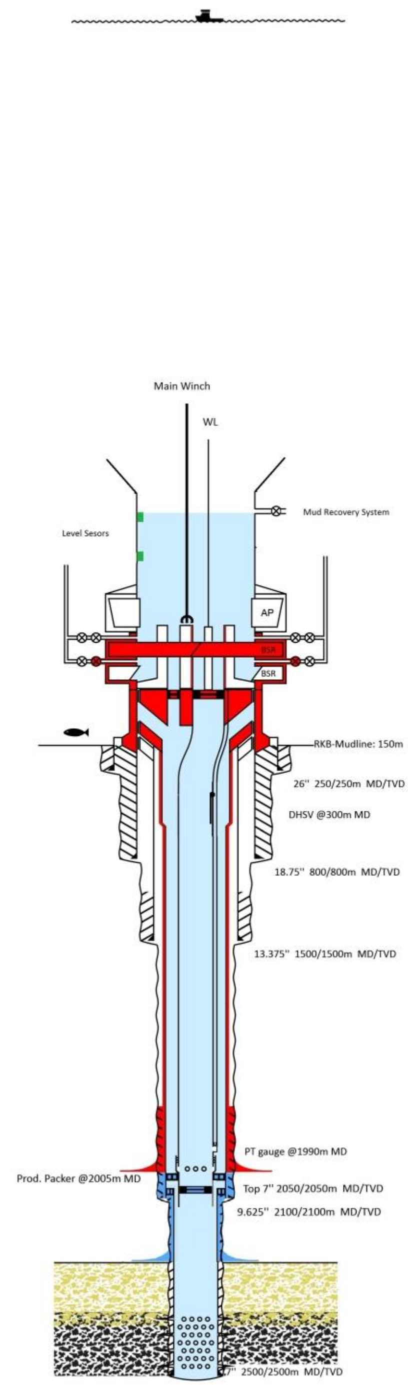
29	x	Unlock THERT and lay down			3
30	x	Make up TH Handling Tool, pick up hanger and reset slips			3
31	x	Using tubing shear - shear tubing above coupling	Rather than spend time backing out the tubing joints it is proposed to utilize an "off the shelf" hydraulic tubing shear ("hands free" and remotely operated) to cut the tubing. Also it is proposed to cut the tubing with the control cables and gauge cable in situ - no manual intervention to remove clamps and spool the line and cable.		3
32	x	Lay down tubing hanger			3
33	x	Pick up on main winch and recover remaining tubing	An option is to wet store the production tubing if lack of storage capacity.		3
34	x	Set tubing in slips			1
35	x	Using tubing shear - shear tubing above coupling			1
36	x	Lay down tubing hanger			1
37	x	Repeat sequence as above until all tubing is recovered			1
			Installing Primary WB		
38	6	Install RLCT stack onto SSD			1
39	6	Run CBL prior to log annulus cement behind 9⅝"	WL operation (PCH on RLCT stack). CBL showed partly cement in annulus and poor cement bonding towards casing.		1
40	x	Prepare to run HydraHemera on CT prior to set the primary cement WB	The BHA is run together with CTH and lubricated into the RLCT stack.		2
41	7	RIH perforation guns and perforate minimum a 50m MD section above the production packer. Retrieve guns after perforation	In this case we perforate at top of PBR to avoid perfoarting through PBR. The lower most guns are located @2010m MD. Might require two or more runs on WL (PCH) due to the restriction set by the lubricator length		1
42	8	RIH HydraHemera on CT to the setting depth	NORSOK D-010 requires minimum 50m logged cement in annulus and pressure test and tagging of the internal cement		2
43	8	Wash the perforated section to ensure good bonding (4 bpm)	On top of HydraHemera there is a Indexing tool rotating 30 degrees to change the washing jet direction. To wash sufficiently the HydraHemera need several runs (in the perforated section), each run with a new washing jet direction.		2
44	8	Cement the washed section	Inject cement while pulling out. Cement "pushed" into annulus with the assistance of the		2
45	8	WOC			1
46	9	POOH HydraHemera	If no experience using the HydraHemera on present field, one have to drill a hole in the internal WB prior to log the external WB (annulus cement). Drill the hole using CT and run a CBL on WL. With experience and approval the permanent WBs can be set without drilling and logging.		2
47	9	RIH with CT w/drilling assembly to drill a hole in the internal cement WB.	(CTH). May depend on the operator. Could be sufficient to perform a negative inflow test. Depending on pressure losses, it might require a subsea pump.		2
48	9	POOH CT with drilling assembly			2
49	x	Log external cement WB	WL (PCH). To verify sufficient cement bonding (casing-cement-		2
50	x	RIH with CT w/cement stinger and perform remedial cementing of the internal cement WB.	(CTH)**. If the CBL show poor quality cement this could be a show stopper.** Next step would be to use the PWC above the failed section (dependent on formation integrity) from the RLWI vessel. Otherwise, section mill/underream the failed section with a semi-sub.		2
51	x	WOC			1
52	x	Pressure test and tag cement	Tag it with CT		1
53	x	POOH CT w/cement stinger			2
			Installing Secondary WB		
54	x	Prepare to run HydraHemera on CT prior to set the primary cement WB			2
55	x	RIH perforation guns and perforate minimum a 50m MD section above the production packer.	WL (PCH)		2
56	10	RIH HydraHemera on CT to the setting depth	CT (CTH)		2
57	10	Wash the perforated section to ensure good bonding (4 bpm)			2
58	10	Cement the washed section			2
59	x	WOC	The good results of setting the Primary WB allowed us to skip drilling and logging the Secondary WB		1
60	x	Pressure test and tag cement	Tag cement with CT		1
61	x	Pull RLCT Stack			1
62	x	Pull SSD			1

Intermediate Abandonment					
63	11	Install mechanical plug @225m MD (from RKB) and pressure test	WL. Foundation for the upcoming open hole to surface barrier	✓	1
64	11	RIH SWAT assembly and land off in the 10¾" casing hanger	The 10¾" casing hanger is often referred to as 9⅝" casing hanger. **Note** that the section from WH to DHSV is 10¾".	✓	1
65	11	Inflate packers	Perform pressure test	✓	1
66	11	Fire lower guns @220m MD (from RKB) into 10¾" prod csg.		✓	1
67	11	Fire upper guns @170m MD (from RKB) into 10¾" prod csg.	Between the two packers . Circulation path is now established	✓	1
68	11	Pump clean up pill, spacer and then cement	Cement established in the annulus (10¾" x 13⅜")	✓	1
69	11	WOC		✓	1
70	12	Fire the second pair of lower perforations guns into 13⅜" int. csg.	Perforation goes through 10¾" casing and cement and exposes the new annulus (13⅜" x 20")	✓	1
71	1	Fire the second pair of upper perforations guns into 13⅜" int. csg.		✓	1
72	2	Pump clean up pill, spacer and then cement	Cement established in the annulus between 13⅜" x 20" + Internal cement WB in 10¾"	✓	1
73	12	WOC		✓	1
74	12	Pressure test the open hole to surface barrier		✓	1
75	x	Deflate packers and recover SWAT assembly		✓	1
Wellhead and Conductor Removal					
76	13	Cut and retrieve WH and conductor	WL (cut) and main winch (retrieve)	✓	1
77	x	ROV survey after operation		✓	1

11.2.3 Well Barrier Schematics

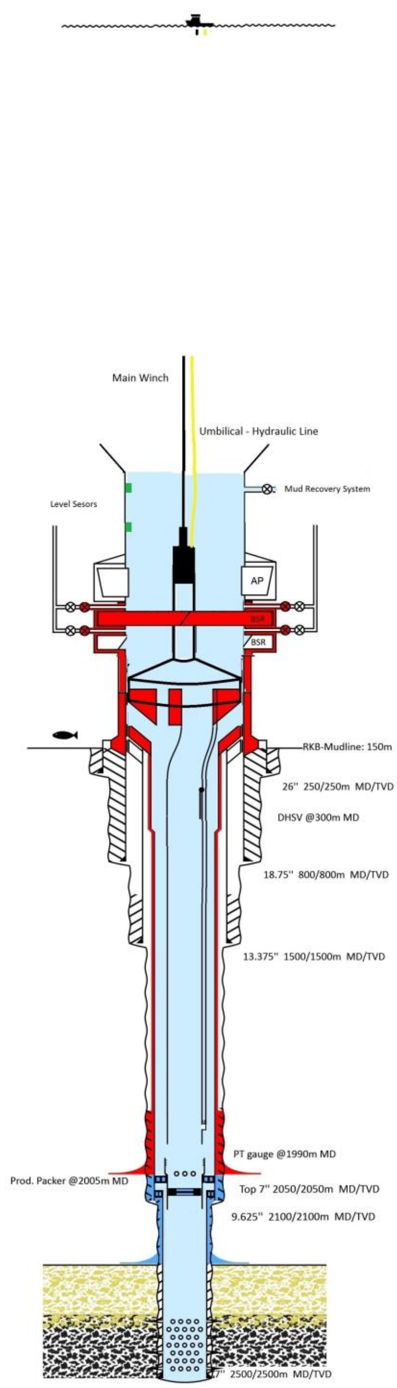


WBS 4



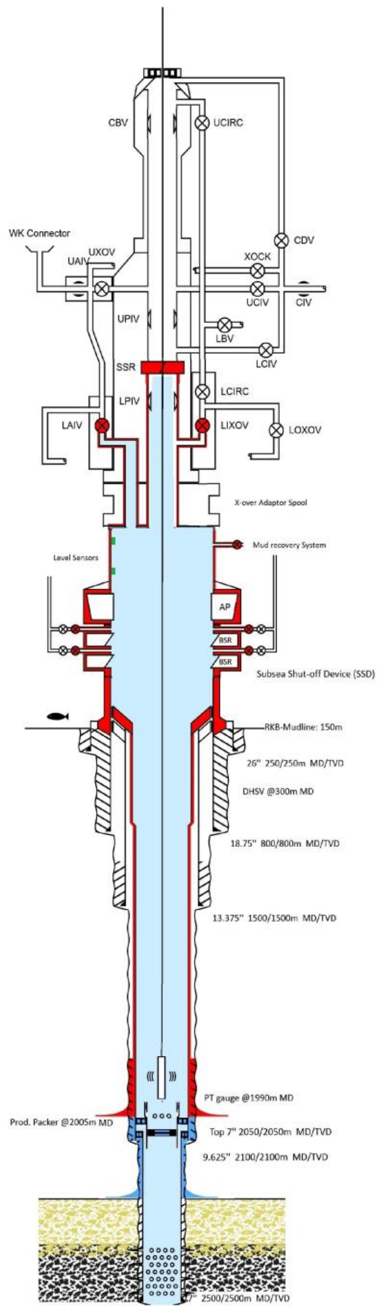
Sequence 17-20

WBS 5



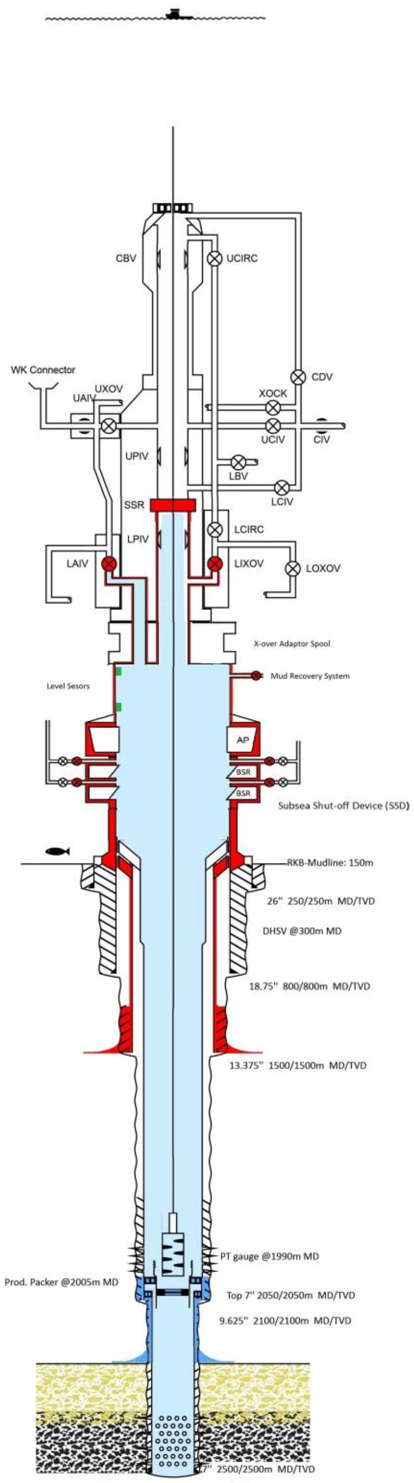
Sequence 21-26

WBS 6



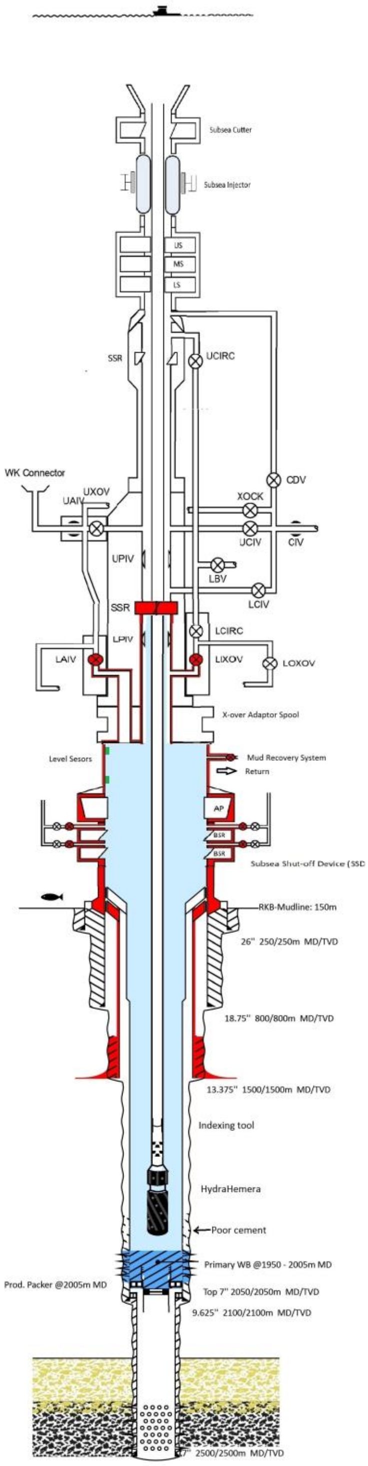
Sequence 38-39

WBS 7



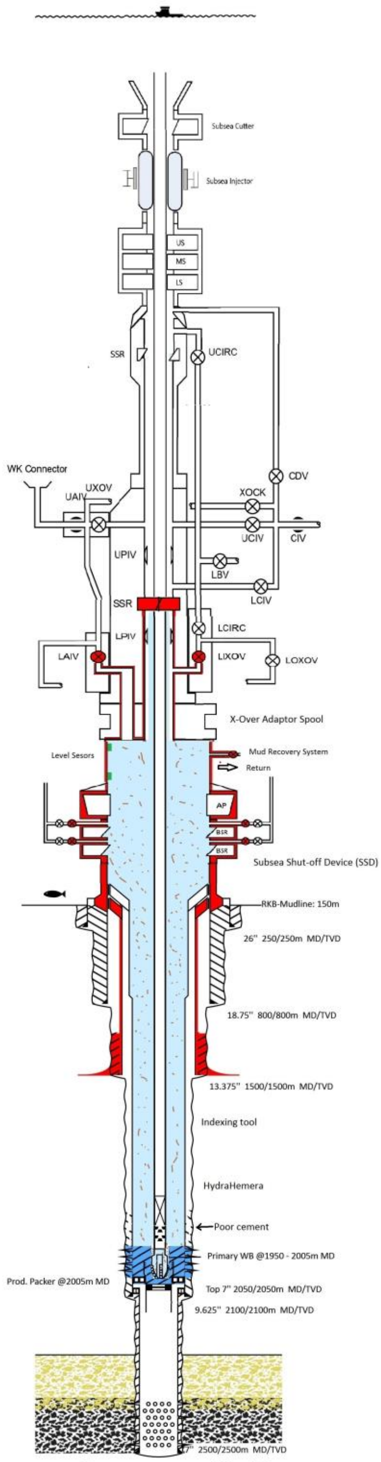
Sequence 41

WBS 8

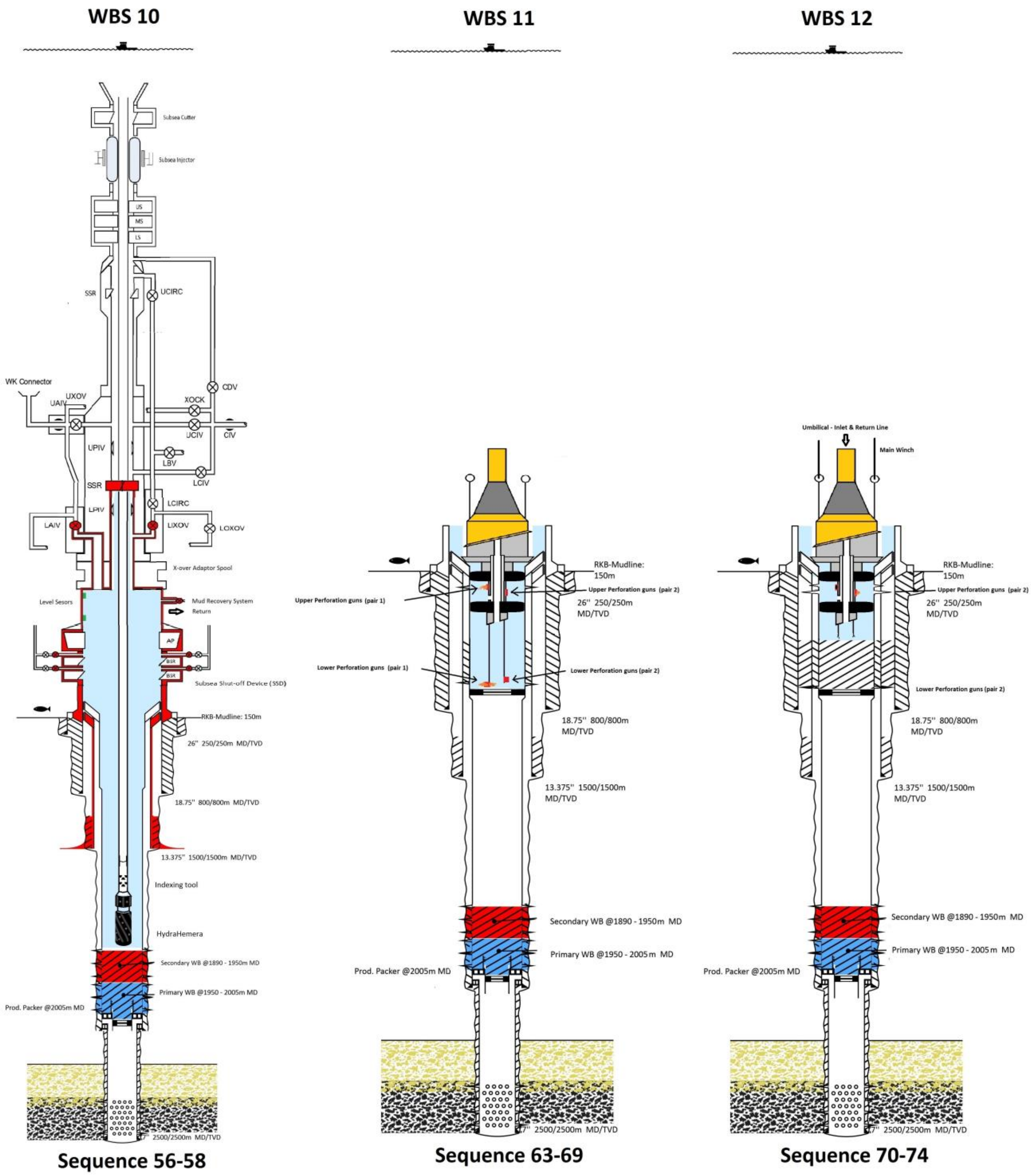


Sequence 42-45

WBS 9



Sequence 46-48

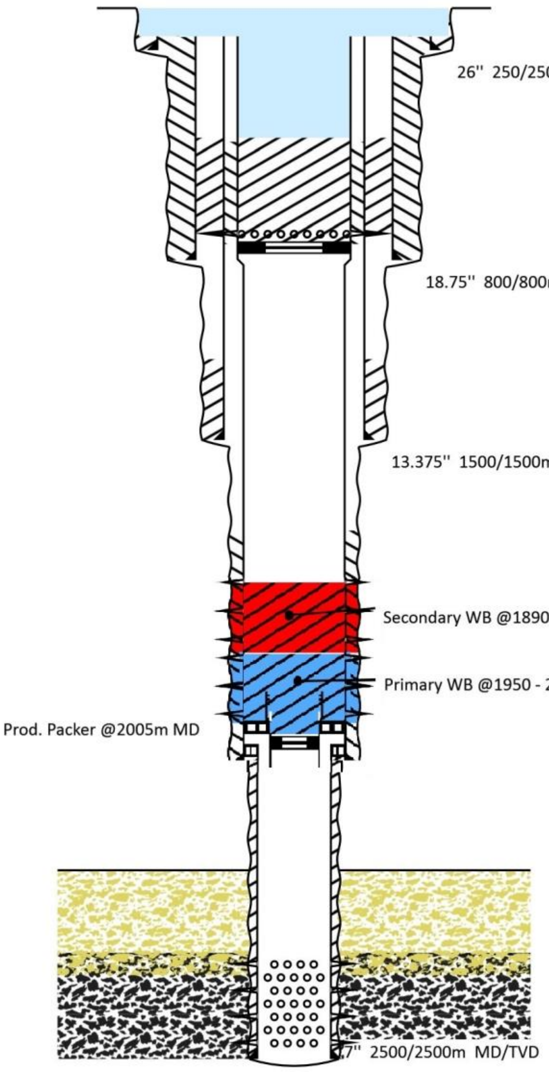


Sequence 56-58

Sequence 63-69

Sequence 70-74

WBS 13



Sequence 76

11.3 Well C – Cut & pull casing strings

11.3.1 Well C Specification

Well C is an old gas producer that is currently shut-in due to its low production and revenue. Its 140m thick gas reservoir has a thin oil layer of 2-4m, where future anticipated reservoir pressure is 150 bar and current reservoir pressure is 138 bar. SIWHP and A-annulus pressure are monitored and measured to 100 bar. We can therefore assume that the 7” production tubing is leaking. There is an additional shallow source of inflow in the overburden with moderate flow potential (e.g. Lista formation) and it will require a primary and secondary WB.

There are no logs available to evaluate the cement job during well construction. This P&A operation will therefore require casing removal and/or remedial cementing job. The casing hanger seal assemblies in this well are unlocked by a vertical pull. At least one WBE has failed, most likely the production tubing. However, the well did not have any issues when shut-in. If the pressure in A-annulus re-builds when bled off, it would be defined as sustained casing pressure (SCP)[63]. If both A-annulus pressure and pressure in production tubing decreases during the bullheading operation, we can assume that the production tubing is leaking.

If the casing hanger and casing have an estimated force to be unseated within the main winch’s limit, we could avoid using the subsea jacking unit. For this case, the SSD will be applied and it is accommodated with three set of rams, i.e. two seal/shear rams and one slip ram.

11.3.2 Operational Sequence

Well C

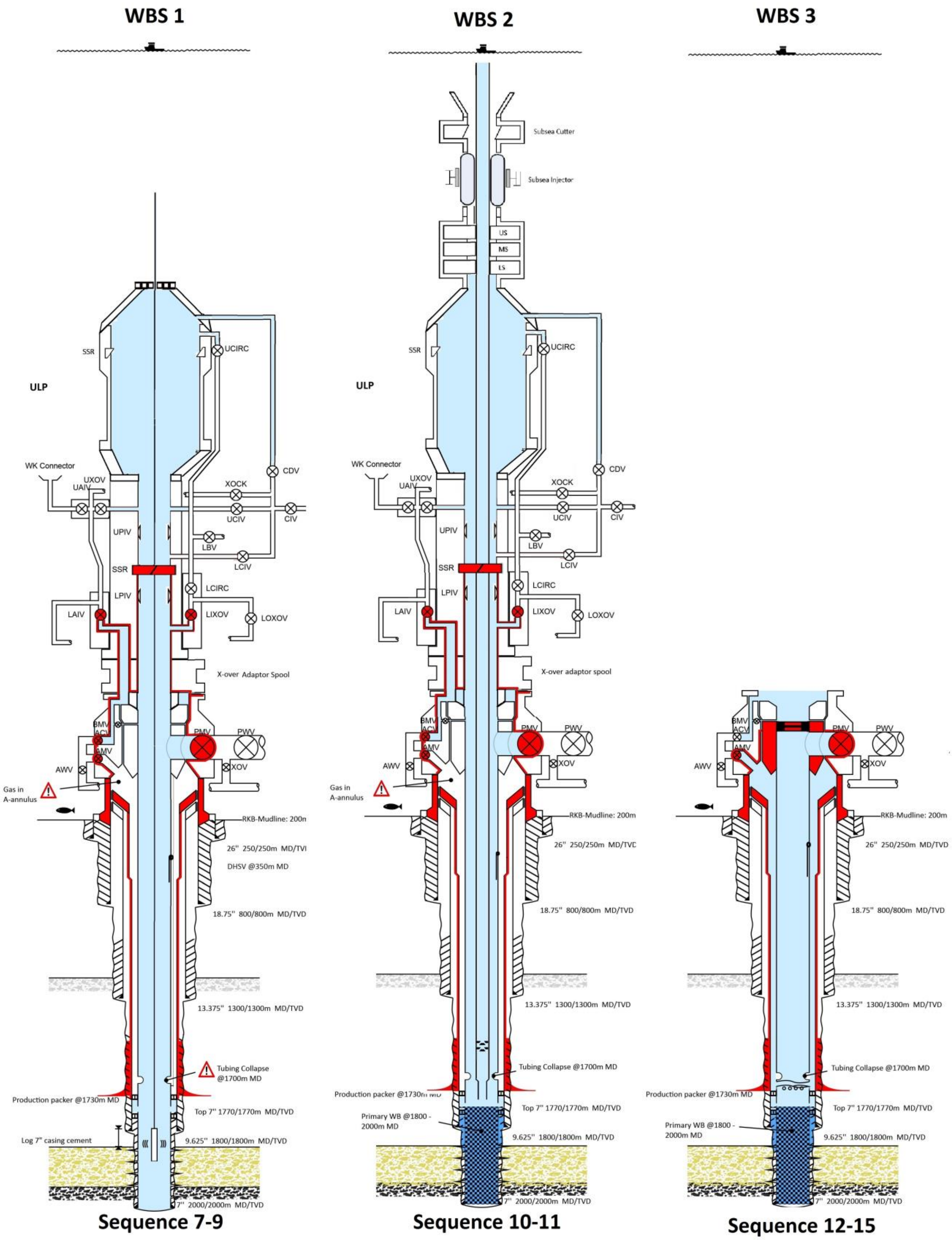
Pre-Assumptions		
	1	No cement log available
	2	The cement quality and TOC is unknown behind all casing strings
	3	One sources of inflow in the overburden formation. No hydrocarbons
	4	
Standard Operation	5	
Technology Provided, Little or no Experience	6	
Technology Not Provided		

Seq. No.	WBS	Description	Comment/Reference	Abandonment Complexity (Type)
1	x	Arrive 500m zone, DP trial		
Preparatoy Phase				
2	x	Recover tree cap and clean re-entry hub	WL	1
3	x	Install RLCT stack on top of HXT	Prepare for WL (PCH)	1
4	x	Retrieve upper crown plug on WL		1
5	x	Retrieve lower crown/tubing hanger plug on WL		1
6	x	Kill well, bullhead	Monitor A-annulus pressure. If pressure decreases, the tubing is leaking (neglecting temperature effect). Keep a high flow rate (min 1200 l/min) to bullhead the gas into the reservoir. 30/70% MEG and Seawater or Brine could be used.	1
7	1	Drift run w/caliper log or mechanical	Ensuring no obstacles/large enough OD for the upcoming tools	1
8	1	Production Tubing collapse @1700m MD	Unable to set mechanical plug in tailpipe. Min ID = 4.5" in the collapsed region. Able to pass restriction with CT	1
9	1	Run CBL from top of reservor @1860m MD to production casing shoe @1800m MD	Log shows good quality cement and bonding in the 60m logged interval. Not necessary to log to top of 7" liner hanger because it is not possible to confirm good cement behind 9⅝" casing (two casing strings)	1
Reservoir Abandonment				
Installing primary WB #1				
10	2	RIH 2⅞" CT w/cement stinger to inject SandaBand into reservor and up to liner hanger packer	RIH with CTH. This gas tight slurry acts as the primary WB against the reservoir and will stop potential inflow of gas. Sandaband installed from 2000m MD to 1760m MD. But Primary WB cross-section is within the requirements from 1800 - 2000m MD	2
11	2	Tag top of slurry and POOH CT	To tag TOC, one can increase pump rate to identify sand in the return.	2
Recover production tubing				
12	3	Punch and cut production tubing with WL	WL (PCH). Between production packer and collapsed zone. If unable to pass the restricted zone, one should make the cut as close to the restriction prior to log the cement behind production casing.	1
13	3	Circulate annulus (down prod. Tubing and up A-annulus)	Monitor pressure (bleed and feed) and circulate with 30/70% MEG and Seawater or Brine. Returns sent to vessel and gas is separated out in the HC vent system. After ciculation, the A-annulus and main bore pressure should be normal.	1
14	3	Install shallow remote open/close plug in tubing hanger prior to pull RLCT Stack	WL (PCH)	1
15	3	Pull RLCT stack	Lock open DHSV before retrieving stack	1
16	4	Install SSD and subsea jacking unit	The Mud recovery system will also be a part of this system and a *Slip Ram* is added	1
17	4	Pick up the hydraulical THERT assembly c/w umbilical. (run on main winch)	Although the THERT is an existing tool , the landing string must be developed in order to perform this job on main winch	3
18	4	Run THERT into subsea jacking unit, SSD and HXT		3
19	4	Slack off on main winch to land in TH and activate subsea jacking unit slips onto landing string	Subsea jacking unit ensures that the THERT is centralized	3
20	4	Function THERT - latch to TH	Hydraulically activated	3
21	4	Function THERT - unlock TH from XT	This operation is a combined operation; By pulling the THERT assembly with the subsea jacking unit we are unlocking the TH from the XT.	3
22	4	Retrieve prod. Tubing and THERT (w/assembly) on main winch	If tubing hanger and tubing is stuck due to lack of pulling force, it would be a show stopper.	3
23	x	Set tubing in slips	In false rotary table. Alternative: Activate Slip ram in SSD to lock	3
24	x	Unlock THERT and lay down		3

25	x	Make up TH Handling Tool, pick up hanger and reset slips	Any LSA/NORM issues will be adressed by the vessels standard operating procedures.		3
26	x	Using tubing shear - shear tubing above coupling	Rather than spend time backing out the tubing joints an alternative is to utilize an "off the shelf" hydraulic tubing shear ("hands free" and remotely operated) to cut the tubing. Could also cut the tubing with the control cables and gauge cable in situ - no manual intervention to remove clamps and spool the line and cable.		3
27	x	Lay down tubing hanger			3
28	x	Pick up on main winch and recover tubing			3
29	x	Set tubing in slips			3
30	x	Using tubing shear - shear tubing above coupling			3
31	x	Lay down tubing hanger			3
32	x	Repeat sequence as above until all tubing is recovered			3
33	x	Pull Subsea jacking unit			1
		Install Secondary WB #1			
34	x	Install RLCT stack (without WCP) on top of SSD	Well is in overbalance		1
35	x	Perform logging of 9⅝" cement	WL (PCH).		1
36	x	Evaluation of cement bonding log behind 9⅝"	Good quality annulus cement from production packer @1730m MD to 1650m MD. TOC was located at 1570m MD.		1
37	x	Install mechanical plug in tailpipe and pressure test	Since we do not have 100m good quality annulus cement, we install a mechanical foundation to fulfill the requirements (i.e. min. 50m MD cement plug)		1
38	5	RIH CT w/cement stinger and install secondary WB	(CTH). Pump and pull to install min. 50m MD cement plug		2
39	5	WOC			1
40	5	Tag TOC			1
41	x	POOH CT w/cement stinger			2
		Intermediate Abandonment			
42	6	Punch 9⅝" @1300m MD	Monitor pressure (bleed or feed as required).		1
43	6	Punch 9⅝" (10¾")@10m below casing hanger	Monitor pressure (bleed and feed as required). Ensure zero pressure differential between annulus and main bore		1
44	6	RIH cutting tool and cut 9⅝" @1300m MD	Could use the WL assisted jet cutter from Halliburton		1
45	7	RIH CT c/w multiple set inflatable packer	Packer is used to enable circulation of annulus (9⅝" x 13⅜"). Pump through packer		2
46	7	Activate packers below punched (upper) area	inside 9⅝" casing		2
47	7	Circulate annulus (down 9⅝" casing and up annulus)	Circulate out old mud and clean up annulus		2
48	x	Install shallow remote open/close plug in 9⅝ casing above the upper punched area	WL (PCH)		1
49	x	POOH CT	CTH		2
50	x	Pull RLCT Stack (without WCP)			1
51	x	Pull SSD and HXT	May require two runs		1
52	8	Install SSD and subsea jacking unit	With Mud recovery system		1
53	8	RIH Casing Hanger Seal Assembly Retrieval Tool (CHSART) lock into casing hanger seal assembly	Subsea jacking unit can assist with downwards force to ensure CHSART locks into the seal assembly. CHSART assembly consists of the retrieval tool and a landing string (THERT landing string) and RIH on main winch		4
54	8	Pull and unlock casing hanger seal assembly	Close annular preventer and monitor pressure (bleed or feed as required). Open the remote close/open plug		4
55	x	POOH CHSART	Open annular preventer and POOH		4
56	x	RIH a Pull Spear prior to pull 9⅝" casing	RIH Pull Spear assembled with landing string (THERT landing string) and apply a straight vertical pull. Great overpull might be required to release the casing hanger and casing. Activate Subsea Jacking Unit to pull casing if unable to pull with main winch. If casing is stuck, one must perform several trips with cut and pull. If the casing is still stuck it would be a show stopper.		4
57	x	Activate slips on Subsea jacking unit and hydraulically lift (some inches) with straight upward force to unseat casing hanger and casing	When casing hanger and casing is free, one can retrieve it on the main winch.		4
58	x	Set casing in slips	Alternative: Use the Slip Ram in SSD		4

59	x	Unlock Pull Spear			4
60	x	Cut casing and lay down			4
61	x	Pick up casing on main winch and recover casing			4
62	x	Set casing in slips			4
63	x	Cut casing and lay down			4
64	x	Repeat sequence as above until casing is recovered			4
65	x	Pull Subsea jacking unit			1
Install Primary & Secondary WB #2					
66	x	Install RLCT Stack (without WCP) onto SSD			1
67	x	Logging 13⅜" casing	WL (PCH). Log shows good quality cement and bonding @1120 - 1250m MD.		1
68	x	Install Mechanical plug above shallow shource of inflow in 13⅜" casing @1250m MD	WL (PCH). Act as a foundation for the upcoming cement job. Unable to run mech plug through RLCT stack		1
69	9	RIH CT w/cement stinger and install a single cement plug in combination with mechanical plug	CTH. Pump and pull minimum 100m MD of cement inside 13⅜" casing		1
70	9	WOC			1
71	9	Tag TOC			1
Install Open Hole to Surface Barrier					
72	x	Punch/perforate 13⅜" casing @350m MD	WL (PCH). Monitor pressure (bleed and feed as required)		1
73	x	Punch/perforate 13⅜" casing @201m MD (as close to the csg hanger as possible)	Approx. 10m below casing hanger. WL (PCH). Monitor pressure (bleed and feed as required)		1
74	x	RIH cutting tool and cut 13⅜" casing @349m MD	Abrasive cutting tool		1
75	10	RIH CT c/w multiple set inflatable packer	Packer is inflated between 13⅜" casing hanger and punched area		2
76	10	Activate packer below the upper punched/perforated area	Packer is used to enable circulation of annuslus 13⅜" x 20")		2
77	10	Circulate annulus (down 13⅜" casing and up annulus)	Circulate out old mud and clean up annulus. The Wellbore is now clean and there should not be any risks related to inflow or pressure build-up the final stage of this P&A operation		2
78	x	Pull RLCT Stack (without WCP)			1
79	11	RIH Casing Hanger Seal Assembly Retrieval Tool (CHSART) lock into casing hanger seal assembly	CHSART assembly consists of the retrieval tool and a landing string (THERT landing string) and RIH on main winch. Apply enough weight on landing string to be able to latch into Seal Assembly. If unable to latch into the seal assembly we need to install the Subsea jacking unit for assistance.		4
80	11	Pull and unlock casing hanger seal assembly with main winch	Close annular preventer and monitor pressure (bleed or feed as required).		4
81	11	Pull seal assembly with CHSART on main winch	Open annular preventer		4
82	x	RIH a Pull Spear prior to pull 13⅜" casing	Great overpull might be required to release/unseat the casing hanger and casing. Install Subsea Jacking Unit to pull casing if unable to pull with main winch. If casing is stuck, one must perform several trips with cut and pull. If the casing is still stuck it would be a show stopper.		4
83	x	Set casing in slips	Alternative: Use the Slip Ram in BOP		4
84	x	Unlock Pull Spear			4
85	x	Cut casing and lay down			4
86	x	Pick up casing on main winch and recover casing			4
87	x	Set casing in slips			4
88	x	Cut casing and lay down			4
89	x	Repeat sequence as above until casing is recovered			4
90	x	Logging 20" casing cement	Log shows good quality cement and bonding @250 - 349m MD		1
91	x	Install mechanical plug in 20" casing @349m MD	If required by company; Perform pressure test		1
92	12	RIH 2" Hose and install open hole to surface barrier	Hose is assisted by ROV into well. The hose could be a multi-spiral, wire reinforced thermoplastic hose (e.g. Black Eagle Hose)		1
	12	Pull SSD and Subsea Jacking Unit			1
93	13	Cut and retrieve WH and conductor	WL (cut) and main winch (retrieve)		1
94	13	ROV survey after operation			1

11.3.3 Well Barrier Schematics



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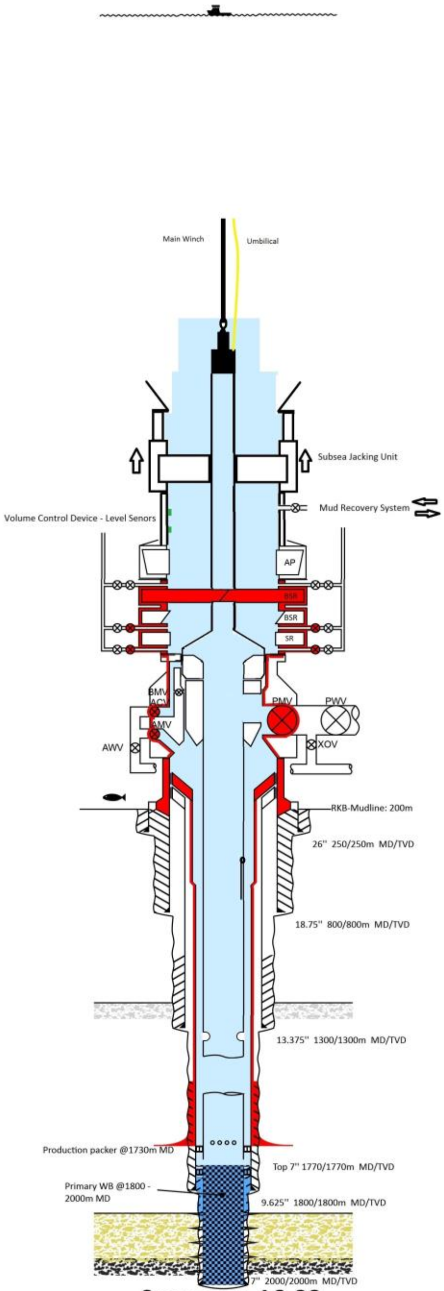
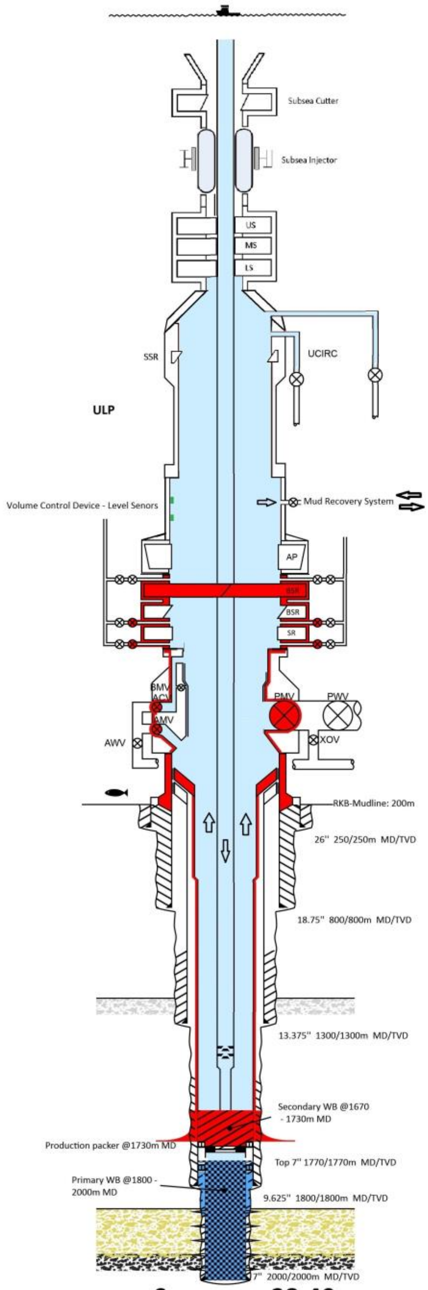


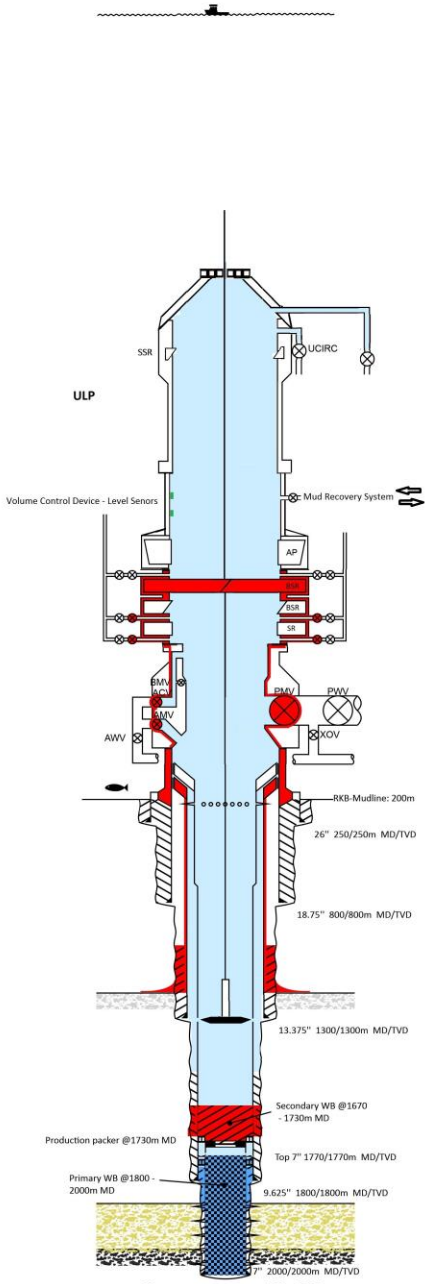
Sequence 16-22

WBS 5



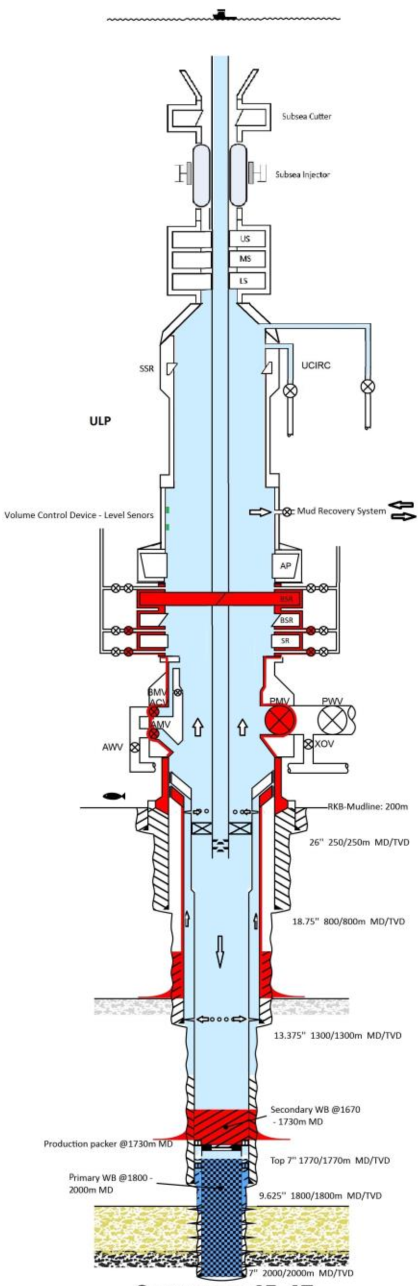
Sequence 38-40

WBS 6



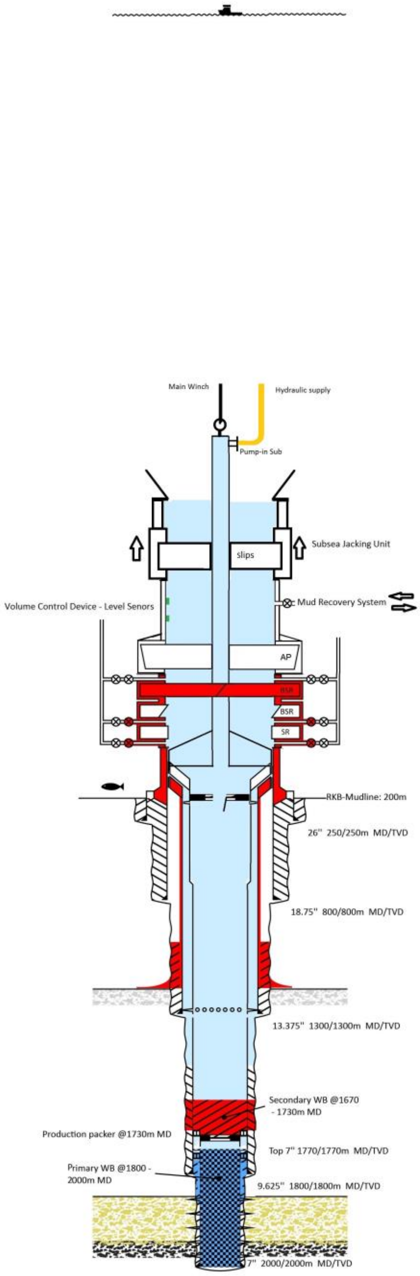
Sequence 42-44

WBS 7



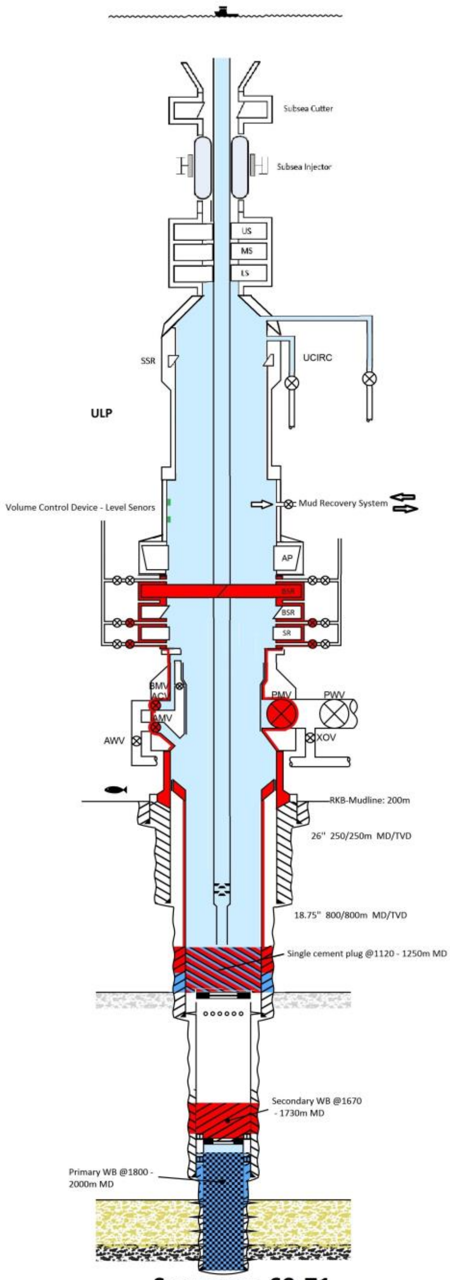
Sequence 45-47

WBS 8

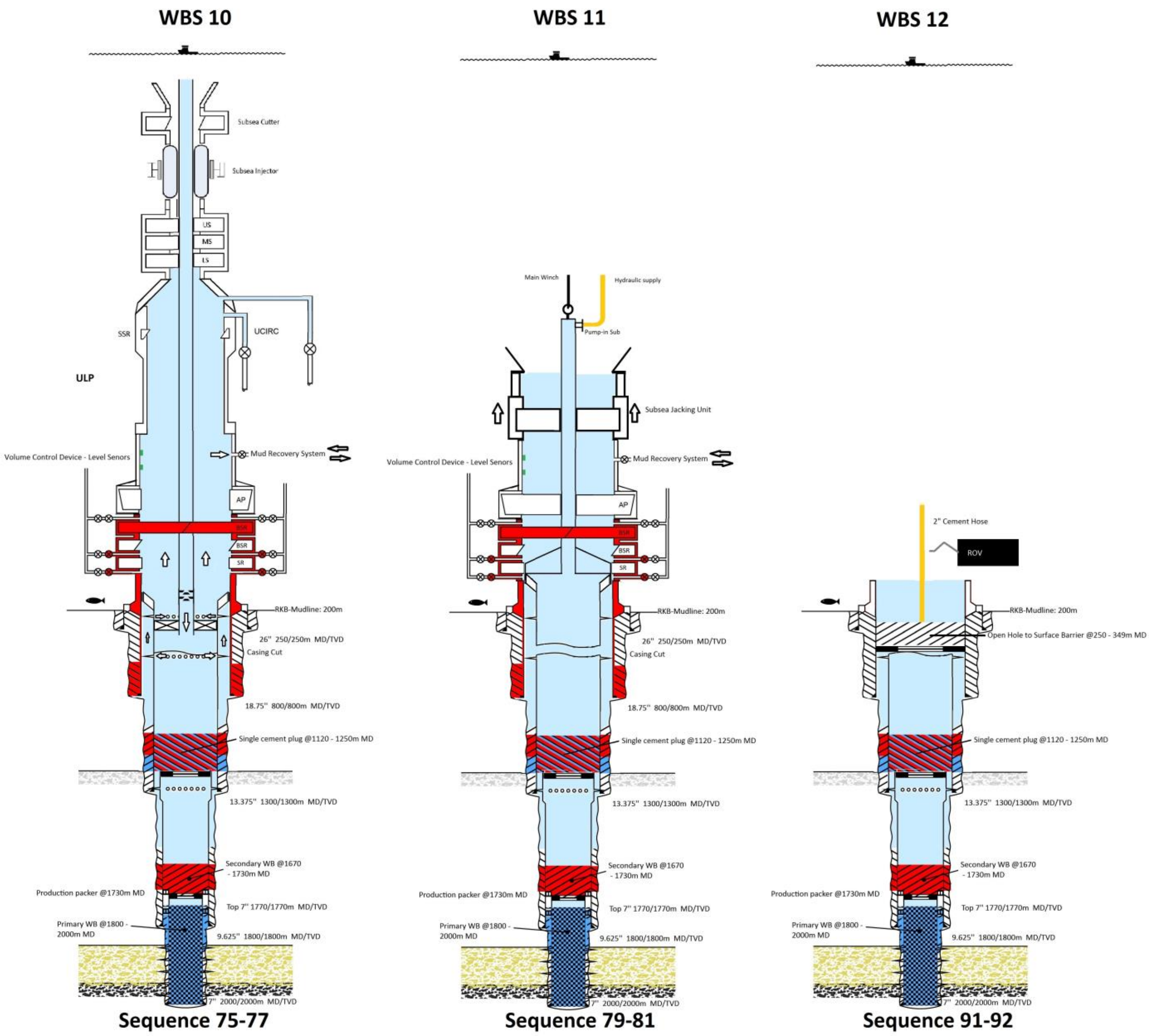


Sequence 52-54

WBS 9



Sequence 69-71



11.3.4 Comments

Cement in liner lap shall be logged. All permanent WB installed in this well are positioned at a depth where the minimum formation stress can withstand the future anticipated pressure at the base of each WB.

12 Discussion

An increasing number of subsea completed wells will have to be PP&A on the NCS in the years to come. The attention of constructing wells with low P&A expenditures is all-time high, subsequently the current subsea wells completed in the 90's are coming to an end of production and these wells were not designed with respect to low cost P&A.

The presented base cases are an effort to reveal the technology gaps of how to conduct riserless P&A operation from a RLWI vessel. With focus on how to maintain well control and utilizing the current practice on a RLWI vessel, the three presented base cases each represents a possible approach of how to conduct a comprehensive PP&A of a subsea well.

The RLWI vessel's current scope of work comprises preparatory work (phase 0) and WH and conductor removal (phase 3). These phases includes WL operation, main winch (e.g. retrieve XT, WH, etc.) and pumping operation.

The base cases have utilized the current practice and included new methods and equipment to allow RLWI vessels to perform reservoir – and intermediate abandonment. Each base case will be discussed in order to cover the main challenges during the P&A operation. As the major problem related areas are related to reservoir –and intermediate abandonment, the preparatory work and the WH & conductor removal is not seen as a direct challenge during the P&A operation.

12.1 Discussion – Well A

This base case assumed that all casing cement were logged and that it was provided with good documentation. As long as TOC and cement bond quality is known, the complexity of the P&A operation is reduced and we do not have to pull any casing strings in this base case.

<u>Provided equipment:</u>

- *RLWI stack (used on Island Constructor)*
- *Hydraulic THERT (to unlock tubing hanger and recover production tubing)*

<u>Additional equipment required:</u>

- *CAT (under development)*
- *THERT Landing String (existing equipment must be combined into an assembly)*
- *Parking frame to park the HXT with production tubing on drill floor and deck (requires development/manufacturing)*

<u>Challenges during P&A operation:</u>

- *Cut tubing and control line*
    - *No problem to cut the tubing, but the cut should be in close range to the control line clamp to ensure a parted control line. One extra run may be required to identify the position of the control line clamp.*
- *Removal of tubing and HXT (alternative 1)*
    - *This method could be applied as long as there are two WB above the reservoir or any other formation with flowing potential. In this case the primary and secondary WB are established, no leaking casing hanger seal assemblies resulting in a pressure build-up in A-annulus and the well has been circulated with an environmental friendly fluid.*
    - *As it is not allowed to work under suspended load, the HXT and tubing would have to be secured at surface. A HXT parking frame would have to be developed to fulfill this requirement.*
- *Removal of Tubing hanger and tubing (alternative 2)*
    - *Dependent on hydraulic THERT as the mechanical THERT requires rotation. It would be possible to use a mechanical THERT, but it involves a greater probability of failure as more subsea equipment is added in the operation.*
    - *Supply with enough weight when landing on TH to be able to latch on.*
    - *Unable to unlock TH from HXT. Main winch is limited to 200 ton (SWL) pulling capacity.*
    - *The landing string assembly must be developed. Should be possible to assemble existing parts and equipment to build it.*
- *Installation of primary – and secondary WB*

  - *To apply through tubing cementing, one must assure tubing integrity to ensure that the cement is transported to the planned plug depth in the wellbore.*
- *Open Hole to Surface Barrier*
  - *Since the cement in the annuli does not have any foundation at its base, one must perform a good cement job evaluation to ensure a proper cement job.*
  - *There is a risk of getting a poor clean up during circulation if the first perforations penetrates both casing. The open holes to surface cement job could therefore be unsuccessful because of poor clean up.*

<u>Well Abandonment Complexity:</u>

The well abandonment complexity “code” is provided to illustrate the complexity of the P&A operation. Even though one additional phase has been added, the complexity of abandonment work remains unchanged (i.e. Type 0, 1, 2, 3 and 4).

SS 1/1/3/1

12.2 Discussion – Well B

This case introduced another familiar problem; once the control line is located a few meters above the production packer the production tubing will have to be recovered, and it immediately increases the well abandonment complexity.

<u>Provided equipment:</u>

- *Hydraulic THERT (to unlock tubing hanger and recover production tubing)*
- *Pump-in Cap (allow greater flow rate)*
- *SWAT (set open hole to surface barrier)*
- *Mud Recovery System (for mud return)*
- *THROT (to guide string/equipment into/out A-annulus or main bore)*
- *HydraHemera (set cement barriers)*

<u>Additional equipment required:</u>

- *RLCT Stack (under development)*
- *THERT Landing String (existing equipment must be combined into an assembly)*

- *Subsea Shut-off Device (SSD) 18¾" ID (existing equipment must be combined into an assembly)*

Challenges during P&A operation:

Several challenges in base case 1 will also apply in this case. However, there are some new additional challenges.

- *Fluid return to vessel*
  - *The total volume of fluid returns are limited and if all fluid returns would have to be stored, this could be a show stopper.*
  - *Island Constructor has a capacity of 219m^3 of fluid returns containing HC. Gas return is excluded because it can be cold flared and will therefore not be stored in tanks.*
- *CT operation*
  - *Installing Primary – and secondary WB is not necessarily a challenge, but the there is only one HydraHemera job performed on CT and therefore not too much experience.*
  - *Two RLCT operations have been performed on the NCS and both did not include well control equipment. Hence, no experience conducting RLCT operations reduces the reliability of the overall RLCT system.*
  - *Fatigue on the CT*
- *Tubing hanger and tubing recovery*
  - *Since 1850m of production tubing is to be recovered, the pulling force to unseat the tubing hanger will most likely be greater than in base case 1 and it might be a show stopper.*

Well abandonment complexity:

SS 1/3/2/1

12.3 Discussion – Well C

This is the most complex base case and all the previous challenges in base case 1 and 2 will also apply here. However, there are some additional challenges related to the RLCT stack and casing retrieval.

Provided equipment:

- *Hydraulic THERT (to unlock tubing hanger and recover production tubing)*
- *Hydraulic CHSART (to unlock and recover the casing hanger seal assembly)*
- *2" Hose (set open hole to surface barrier)*
- *Mud Recovery System (for mud return)*
- *Subsea Jacking Unit (assist with vertical forces)*
- *Pull Spear (recover casing strings)*
- *Jet cutter (cut 9⅝")*
- *Abrasive cutter (cut 13⅜")*

Additional equipment required:

- *RLCT Stack (Redesigned the ID of the WCS from 7 1/16" to 18¾")*
- *THERT Landing String (existing equipment must be combined into an assembly)*
- *Subsea Shut-off Device (SSD) 18¾" ID (existing equipment must be combined into an assembly)*

Challenges during P&A operation:

- *RLCT Stack*
    - *The original ULP (i.e. LS and LLP) on the RLCT stack has an ID of 7 1/16" and causes problems when running larger OD tools, equipment or other objects. This problem will occur when casings has to be retrieved. During the planning of this PP&A it was found that if the ULP was not changed to an ID of 18¾", using the existing ULP would have resulted in 12 extra runs because the stack would have to be pulled (approx. 6hr) and installed (approx. 15hr) in order to*

accommodate larger OD equipment. By changing the ULP the total operational time can be reduced by approximately 126hr (5+ days).

- *Casing hanger seal assembly*
  - *If the subsea jacking unit has a failure, it can be a challenge to supply enough downwards force to latch onto the seal assembly. If the seal assembly needs "right hand" torque (rotation) to be unlocked, additional equipment is required.*
  - *Cement particles in the fluid return during cementing could cause problems because it might leave cement particles in the seal assembly. The result is typically greater overpull, or if stuck it would require milling out the seal assembly. If neither of these allow us to continue the operation, it would be a show stopper.*
- *Casing*
  - *The casing may be stuck due to settled barite, cement at the casing cut.*
  - *Other factors that can might cause additional overpull is highly deviated wellbores.*
  - *The casing hanger may require great overpull to overcome the frictional forces between the casing hanger and inner wall of XT.*
- *Storage capacity*
  - *This base case includes a lot of equipment that occupies the deck space for storage.*
  - *Accommodate temporary tanks store the fluid returns may be hard due to the already limited storage capacity*
  - *1525m of production tubing, HXT, 1100m of production casing and 149m of intermediate casing must be stored. These casing strings may have to be wet stored at seabed.*

<u>Well abandonment complexity:</u>

SS 1/3/4/1

12.4 Discussion Summary

The intention with the base cases was to reveal at which point additional equipment and/or technology would have to be provided during the operation and to identify the RLWI vessel's limitations. By evaluating the current technology gaps and limitations, one can identify the potential subsea well candidates to be P&A'ed from a RLWI vessel.

Storage capacity of fluid returns

The first issue we are facing is how to handle the fluid returns during the preparatory phase, i.e. the well is bullheaded and A-annulus is cleaned up and displaced with a suitable fluid (e.g. brine). The wellbore fluids in the production tubing is bullheaded into the reservoir and should not be an issue as long as the reservoir has injectivity. The A-annulus fluid could also be bull-headed into the reservoir (after punching the tubing) before setting a mechanical plug in tail-pipe (except remote open/close plugs).

In these base cases, the A-annulus fluid has been sent back to the vessel for storage. The problems occurs when there is no injectivity and both the main bore and annulus fluid must be pumped to surface for storage. Displacing and cleaning up the well produces large volumes of fluid return. The storage tanks on Island Constructor could reach its storage limitation if taking into account its AoC, allowing it to handle 5m^3 of fluid returns. Hence, it would limit the upcoming clean-up jobs of B – and C annulus and other operations that includes circulation. The solution would be to send the fluid returns to a wastewater treatment system after free and large amount of dispersed gas has been separated out through the integrated HC vent system on Island Constructor. This will allow larger amount of fluid returns because the gas is cold flared, environmental harmful chemicals is stored and the treated water is disposed to sea.

Production tubing and casing strings retrieval

The production tubing is either pulled after it has been cut or if completed with a PBR it could be pulled straight out. Even though the entire production tubing is not recovered, the TH and parts of the tubing will have to recovered prior to installing the open hole to surface barrier. Recover the production tubing without the use of drill pipe presents additional challenges as the drill pipe can be rotated and is a conduit for conveying fluid. To be able to recover the tubing from a RLWI vessel it would require hydraulic THERT to avoid additional equipment to engage rotation and to simplify the operation. The THROT is landed on TH inside the VXT and the SSD is used as well control equipment. Hence, it is not used for pulling the tubing, but to accommodate wireline entrance when pulling tubing hanger – and annulus plug (VXT).

As the production tubing and casing strings will require great pulling force, it may not be sufficient to perform the pull with the main winch. The main winch is limited to 200ton safe working load (SWL), it is prone to elongation as it is a braided wire, and vessel drift off increases the overpull due to uniaxial pull. To ensure a safe retrieval of production tubing, seal assembly or casing it would better to use a subsea jacking unit unaccompanied or in combination with the main winch. Performing P&A operation from a RLWI vessel with tubing removal is possible. However, cut & pull of casing strings is a heavy operation regardless of using semi-sub or RLWI vessel. There are numerous of variables that weigh against using a RLWI vessel on subsea wells that requires cut &pull.

The Seal assembly on the production casing and intermediate casing must be removed in order to pull the casing strings. There are different suppliers of well completion and that poses a challenge as the seal assemblies may be different in design and they are either unlocked with rotation or a straight vertical pull. The casing hanger seal assembly retrieval tool is a simple tool with dogs latching into a locking profile, but the retrieval tool may differ because of the different suppliers of seal assemblies. The last base case are dependent on seal assemblies that are unlocked by a straight vertical pull because it simplifies the operation substantially.

Alternative 1 in base case A comprises the combined retrieval of HXT and production tubing. The reason for suggesting this method is that it would be an easy operation for a RLWI vessel as the retrieval is conducted with the main winch and it typically requires less overpull than retrieving the TH. As the installed permanent WB seals any formation fluid from entering the well, the residual casing strings (w/ seal assembly) and the hydrostatic column will act as WB during the retrieval. This method could most likely be applied on several wells as long as a risk assessment is thoroughly done. This method has not been performed on a semi-sub to my knowledge, most likely because it would not be faster to use this method on a semi-sub and secondly the rig cannot lift the HXT and production tubing directly up to the drill floor, only to the cellar deck. However, this is possible on a RLWI vessel (Island Constructor) because the HXT and production tubing can be lifted up through the moonpool and the moonpool doors can be closed. After the HXT has been parked on a custom frame and the production tubing has been cut, there is enough space through the derrick opening to skid HXT away from the drill floor to its parking slot.

Annulus barrier

In cases where remedial cementing in annulus or establishing a cross sectional barrier (e.g. HydraHemera) it should be assured that the cement does not displace less dense fluid below. The theory is that since the cement most likely has a higher density than the fluid in annulus, the cement could slowly flow below the planned setting depth. Different methods could be applied to avoid this; obviously ensure there is a fundament at the base of the cement, expand the casing (e.g. explosives) to create a foundation, inject ThermaSet with equal density as the annulus fluid or remove the casing prior to set a mechanical plug to act as a foundation. Nevertheless, Creeping formation (e.g. Shale and salt) could reduce the time spend on remedial cementing.

Standard P&A challenges

There are several challenges during P&A and many of these could be removed by introducing new technology and methods. By removing one or more of these challenges, it would be a substantially increase in the potential number of well candidates for riserless P&A from RLWI vessel.

- *Logging through multiple casing strings*
    - *This technology could save the industry for billions of dollars during P&A.*
- *Tubing left in hole w/control line at permanent WB setting depth*
    - *Large scale tests of cementing the control line under various conditions and with different cement properties has been performed with successful results. However, it is yet to be field proven.*
    - *Hydrawell is developing a rig-less tool, HydraArtemis, that can be run on CT. The intention is to use explosives to shoot of the control line, next up is to use*

explosives to expand the production tubing and casing towards the formation/cement prior to crush the control line and create an annular foundation[53]. See Appendix C.

- *There are solutions for downhole removal of production tubing, but they are not field proven or they are time consuming. E.g.*
  - *Melting the tubing*
  - *Remove sections of tubing by pushing it down and crush it.*
  - *Spiral cutting to ensure that the control line is cut at several locations*
  - *Use chemicals to remove tubing; it is a time consuming operation.*

- *Challenge the prescriptive rules in NORSOK D-010 to reduce the P&A expenditures*
  - *Number of permanent WB, plug length, barrier verification method, etc.*
- *Casing removal*
  - *This is a time consuming operation and it is done by either cut & pull or section milling. Section milling during a riserless P&A operation with CT would most likely require very high flow rates to hydraulically rotate the mill and clean the well.*
  - *Interwell's P&A concept is under development and consist of using thermite to melt all steel tubulars and establish a cross-sectional WB.*

RLCT system

By introducing the RLCT system on a RLWI vessel, the scope of work in terms of P&A will increase. Some of the advantages by implementing CT are:

- *The accuracy and quality of the permanent WB installation increases*
- *Pumping application is introduced*
- *Run heavier equipment on CT than WL*
- *Extended reach in deviated wellbores compared to WL (without WL tractor)*

But there are also some limitations

- *How to rotate when that is needed*
- *Milling will not be possible*
- *The CT tensile strength is too low to allow heavy operations (recover casing/tubing)*

Appendix D is an overview of how the P&A operation can be divided into work packages. By introducing the RLCT system, new work packages becomes applicable and subsequently increases the scope of work in terms of PP&A with a RLWI vessel.

Well abandonment classification

The well abandonment complexity in the Oil & gas UK “Guidelines on Well Abandonment Cost Estimation” is defined with a digit (0 to 4) and shall reflect the complexity of abandonment work. Some of the problems are introduced when implementing CT, retrieval of production tubing and casing removal. CT operations are defined as type 2 work, “Complex Rig-less Abandonment”, with riser and it does not denote the real complexity because it is now suggested to do the same operation without a riser. The same problem occurs during retrieval of production tubing and casing strings. These operations are defined as type 3 and 4 complexity, denoted as simple – and rig-based abandonment. All the presented base cases are riserless and without the use complex of a rig (i.e. semi-sub) and should be classified as “Complex Rig-less Abandonment”. The classification of the well abandonment complexity is based on the well characteristics in each phase, see appendix B. To be able to classify the well abandonment complexity and to make an accurate overview of the potential well candidates and cost analysis, the classification chart should be revised.

RLWI Vessel – Island Constructor

The storage capacity of fluid returns have been discussed. Another challenge is the storage capacity during the P&A operation where a lot of equipment have to be stored and secured on deck. If the P&A operation is complex and requires recovery of production tubing and casing, it may not be possible to store it due to limited storage capacity. A solution would be to wet store all tubulars and recover it with a cheap vessel.

The RLWI vessel’s operability with respect to weather is reduced when using the RLCT and RLWI system (Hs =5m). However, since it is a riserless P&A operation, it allows for greater vessel drift-off compared to a semi-sub with a marine riser. One can also plan larger P&A batch campaigns during periods with a good weather window. The RLWI stack should not be operated on subsea wells where the water depth is less than 70m, the RLCT stack is set to 100m.

It is possible to operate at shallower waters, but going below these water depths will limit the RLWI vessel's operability because the allowable weather window is reduced significantly.

The mobilization cost of a RLWI vessel compared to a semi-sub in water depths below 200m is much lower. The reason is that the semi-sub must be anchored when the water depth is less than 200m. This anchoring operation typically adds up to three extra days of mobilization and demobilization.

The vessel's lifting capacity is limited to 200 ton SWL and will require additional equipment (e.g. subsea jacking unit) if it is a heavy operation. Heavy lifting operations from a RLWI vessel should be evaluated carefully. Cut and pull of casing string, as in base case 3, require that the well control equipment is pulled and installed several times, seal assemblies must be unlocked and recovered, and long sections of casing string must be recovered and stored. Hence, there are so many elements involved that the probability of the operation to fail is relatively large.

12.5 Subsea Well Candidates for Riserless P&A Operations

Base case A and B are two subsea well candidates with low complexity and should therefore be good candidates to PP&A with a RLWI vessel. There are different methods and technologies that could be applied to P&A a subsea well within the given requirements. However, which method to apply depends on the complexity of the well. By applying the current - and upcoming equipment and technology presented in this thesis, the RLWI vessel should aim for subsea wells with the following conditions:

- *Fluid returns during circulation*
    - *Send to host facility or to a waste well, i.e. waste water disposal (best solution)*
    - *Separate and store on vessel (alternative solution)*
- *Production tubing*
    - *Control line is located at a depth where it does not interfere with the installation of primary – and secondary WB (best solution)*

- o *If well is completed with HXT, required section of production tubing (prior to install open hole to surface barrier) and HXT should be recovered in a combined operation.*
- o *Control line interfering with the installation of primary – and secondary WB and production tubing must be recovered.*

- *Good documentation of previous cement jobs*
- *Additional sources of inflow that requires two permanent WB should be located below the intermediate casing shoe, to avoid pulling any casing strings prior to log the casing cement*
- *If cut & pull of casing strings are required*
  - o *Seal assemblies that are unlocked with straight vertical pull*
  - o *Should avoid to recover more than 500m due to weight*
- *The fields specific subsea equipment should consist of hydraulically THERT*
- *If annular cementing is needed, it shall be possible to use perforate, wash and cement technology. Section milling not possible today.*

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13 Conclusion

The upcoming “plug wave” of subsea wellbores will require great experience and new technology in order to reduce the vast P&A cost. Subsea wells that does not require the entire production tubing to be recovered and is classified as type 1 according to well abandonment complexity, could potentially be P&A with a RLWI vessel today (i.e. Well A in the first base case).

The RLCT system is under development and its entrance will allow us to increase the scope of work in term of riserless P&A operations. Well B in the second base case is an illustration of the upcoming potential by introducing this system. As approximately 2/3 of all subsea wells are completed with HXT, we could apply the method of combined recovery of tubing and HXT. This method could possibly reduce the cost compared to a semi-sub.

If new technology and methods are introduced (e.g. multiple string logging tool, tubing left in hole w/control line), the concept of using RLWI vessel in complex P&A operation increases. Another important element is the requirement that all new wells shall be design with respect to its life cycle, including P&A. That will increase the number of subsea well candidates to be PP&A with a RLWI vessel, as the complexity of the well is presumably reduced. After combining the presented technologies and methods to adequately conduct riserless P&A operations, an upgraded table of applicable work packages is presented in appendix D.

A large proportion of the current and future subsea wells on the NCS and in the rest of the world will be potential candidates for riserless PP&A with a RLWI vessel. Riserless P&A operations of subsea wells with low well abandonment complexity will most likely reduce the overall P&A expenditures because RLWI vessels has a lower day rate and an effective method of performing the P&A operation.

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15 Appendices

15.1 Appendix A – NORSOK D-010 Table 24 – Cement plug

15.24 Table 24 – Cement plug

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>
1. A program shall be issued for each cement plug installation.
2. For critical cement jobs, HPHT conditions and complex slurry designs the cement program should be verified by independent (internal or external) qualified personnel.
3. The cement recipe shall be lab tested with dry samples and additives from the rigsite under representative well conditions. The tests shall provide thickening time and compressive strength development.
4. Cement slurries used in plugs to isolate sources of inflow containing hydrocarbons should be designed to prevent gas migration and be suitable for the well environment (CO_2, H_2S).
5. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads.
6. It shall be designed for the highest differential pressure and highest downhole temperature expected including installation and test loads.
7. A minimum cement batch volume shall be defined to ensure that a homogenous slurry can be made, taking into account all sources of contamination from mixing to placement.
8. The minimum cement plug length shall be:
<table>
<tr><th>Open hole cement plugs</th><th>Cased hole cement plugs</th><th>Open hole to surface plug (installed in surface casing)</th></tr>
<tr><td>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.</td><td>50 m MD if set on a mechanical/ cement plug as foundation, otherwise 100 m MD</td><td>50 m MD if set on a mechanical plug, otherwise 100 m MD.</td></tr>
</table>
9. Placing one continuous cement plug in a cased hole is an acceptable solution as part of the primary and secondary well barriers when placed on a verified foundation (e.g. pressure tested mechanical/cement plug).
10. Placing one continuous cement plug in an open hole is an acceptable solution as part of the primary and secondary well barriers with the following conditions:
a. The cement plug shall extend 50m into the casing.
b. It shall be set on a foundation (TD or a cement plug(s) from TD). The cement plug(s) shall be placed directly on top of one another.
11. A casing/liner shall have a shoe track plug with a 25 m MD length.
</td><td>API Spec 10A Class 'G'</td></tr>
</table>

<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. For the shoe track to be used as a WBE, the following applies:
a. the bleed back volume from placement of casing cement shall not significantly exceed the calculated volume; and
b. it shall be either pressure tested and supported by overbalanced fluid (see EAC 1) or inflow tested.
3. The strength development of the cement slurry should be verified through observation of surface samples from the mixing, cured on site in representative temperature.
4. The plug installation shall be verified through evaluation of job execution taking into account estimated hole size, volumes pumped and returns.
5. The plug shall be verified by:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging.</td></tr>
<tr><td>Cased hole</td><td>Tagging.
Pressure test, which shall:
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.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>None.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary abandoned wells: The fluid level/pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Common well barrier</td><td>If one continuous cement plug (same cement operation) is defined as part of the primary and secondary well barriers, it shall be verified by drilling out the plug until hard cement is confirmed.
1. An open hole cement plug extended into the casing shall be pressure tested.</td><td></td></tr>
</table>

Table 5: Acceptance criteria given by NORSOK D-010 [4]

15.2 Appendix B - Determining Well Abandonment Complexity

Table 3.1: *Criteria for Classifying PHASE 1 Well Abandonment Complexity*

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

Notes:

1. Sustained Casing Pressure –SCP related to overpressures or hydrocarbons originating from the reservoir(s) indicates that the primary casing cementation has failed and requires repair at the reservoir caprock level.
2. Not cemented casing or liner at the depth of the barrier (cap rock). Also applies to a (not cemented) scab-liner. The casing will have to be milled or removed to place a competent barrier. Note: The length between top of potential inflow (e.g. bottom of caprock formation) and top of barrier must be more than 200 ft to place permanent barrier (assumed that good cement is achievable).
3. Restricted Tubing Access – tubing may contain a fish, stuck plugs, perhaps be collapsed or parted, hence obstructing or limited access to the depth of the deepest permanent barrier, typically the production packer. Access may be restricted due to internal deposits (scale, wax) if not removable or able to provide a seal in conjunction with cement. The tubing will have to be recovered by a rig.
4. Deep gauge or electrical cables, or hydraulic lines – a data or power cable or hydraulic line is not acceptable to cross a permanent barrier and has to be removed. The tubing is to be recovered possibly requiring a rig.
5. Annulus Safety Valve (ASV) – An Annulus Safety Valve may not allow adequate flow for a through-tubing circulation and cementation, thus will require the tubing to be removed, possibly requiring a rig.
6. Packer set above cap rock – if the deepest barrier is to be placed below the production packer, this will have to be milled unless coiled tubing access is possible.
7. Poor access of CT/HWU to site – offshore platform may not be capable of accommodating equipment, crew or crane and a support vessel is required.
8. Multiple reservoirs to be isolated. This can often be achieved will coiled tubing. If not a rig is required to remove the completion and packers as a TYPE 4 operation.
9. Leaking tubing – if the tubing is leaking, it cannot be used as a conduit for pumping cement. This will have to be recovered unless coiled tubing access is possible.
10. High inclination (no wireline access) – due to inclination above 60 deg, wireline access may not be possible for setting wireline plugs and punching casing.
11. Well with good integrity – no limitations for through-tubing rig-less abandonment.

Table 3.2: *Criteria for Classifying* *PHASE 2* *Well Abandonment Complexity*

x:Not Feasible ✓:Required O:Optional		**Well Abandonment Complexity**			
Note #	**Well Characteristics / Condition at abandonment**	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig	**Type 4** Complex Rig
1	Sustained Casing Pressure due to hydrocarbons or overpressures	X	X	X	✓
2	Restricted access to casing	X	X	X	✓
3	Not isolated fresh water aquifers / zones	X	X	X	✓
4	Not cemented casing or liner at barrier depths (cap rock)	X	X	X	✓
5	Not isolated Shallow gas	X	X	X	✓
6	Site does not allow for CT/HWU pumping operations	X	X	✓	O
7	Poor primary casing cementation	X	X	✓	O
8	No tubing in well	X	✓	O	O
9	Inclination > 60 deg above barrier depth (wireline access)	X	✓	O	O
10	Well with good integrity, no limitations, tubing in place	✓	O	O	O

Notes:

1. Sustained Casing Pressure – SCP on any of the casing annuli related to overpressures or hydrocarbon zones shallower than the reservoir, indicates that primary casing cementations have failed and require repair for final abandonment.
2. Casing access restricted – casing may have collapsed or parted, obstructing access to the production packer, where the deepest barrier is anticipated.
3. Fresh water zones – Fresh water zones will require protection if poorly isolated.
4. Not cemented casing or liner at the depth of the barrier (cap rock). Also applies to a (not cemented) scab-liner. The casing will have to be milled or removed to place a competent barrier. Note: The length between top of potential inflow (bottom of caprock formation) and top of barrier must be more than 200 ft to place permanent barrier (assumed that good cement is achievable).
5. Shallow gas not isolated – Un-cemented (low saturation) gas zone will cause leaks to surface when casing is cut and removed. This can be related to Sustained Casing Pressure. Such zones require isolation after the tubing has been removed by a rig. Requires casing removal or milling.
6. Poor access of CT/HWU to site – offshore platform may not be capable of accommodating equipment, crew or crane and a support vessel is required.
7. If primary casing is poorly cemented, then a rig may need to remove long sections of casing.
8. No tubing in well – if the tubing has been removed under Phase 1, a work string is required to place a permanent barrier. This can be provided by CT, HWU, or rig.
9. High inclination (no wireline access) – due to inclination above 60 deg, wireline access may not be possible for setting wireline plugs and punching casing.
10. Well with good integrity – no limitations for through-tubing rig-less abandonment. Only a surface barrier is required that can be placed through the tubing.

Table 3.3: *Criteria for Classifying PHASE 3 Well Abandonment Complexity*

x:Not Feasible ✓:Required O:Optional		**Well Abandonment Complexity**			
Note #	**Well Characteristics / Condition at abandonment**	**Type 1** Simple Rig-less	**Type 2** Complex Rig-less	**Type 3** Simple Rig	**Type 4** Complex Rig
1	Poor integrity of conductor	X	X	X	✓
2	Platform unable to suspend conductor load during raising	X	X	✓	O
3	Water depth beyond limitation for cutting by LWIV (Subsea well)	X	X	✓	O
4	Conductor cutting/retrieval rig-less	✓	O	O	O

Notes:

1. Poor integrity of conductor – An involved programme will be required in case a conductor has poor integrity (corrosion, weak connectors) or a shallow restriction or damage.
2. Platform unable to suspend conductor load during retrieval – The platform may not be strong enough to suspend the heavy conductor load, which may include cemented inner casing.
3. Water depth beyond limitation for cutting conductor by LWIV – The cutting equipment typically used by a Light Well Intervention Vessel (LWIV) may have water depth limitations, beyond which a rig is required.
4. Conductor: Site can accommodate rig-less cutting and retrieval spread or retrieval planned with heavy lift vessel. Site can support loads of raising a multi-string conductor from the seabed, accommodate jacking spread, crane and crew. Annuli are free of polluting fluids. No need to install environmental plug.

   The Operator will need to decide from a budget-holding standpoint whether to include or exclude conductor retrieval in Phase 3, in the event that the conductors are to be retrieved by Heavy Lift Vessel.

Table 6: Criteria for classifying phase1, 2 and 3 well abandonment complexity [7]

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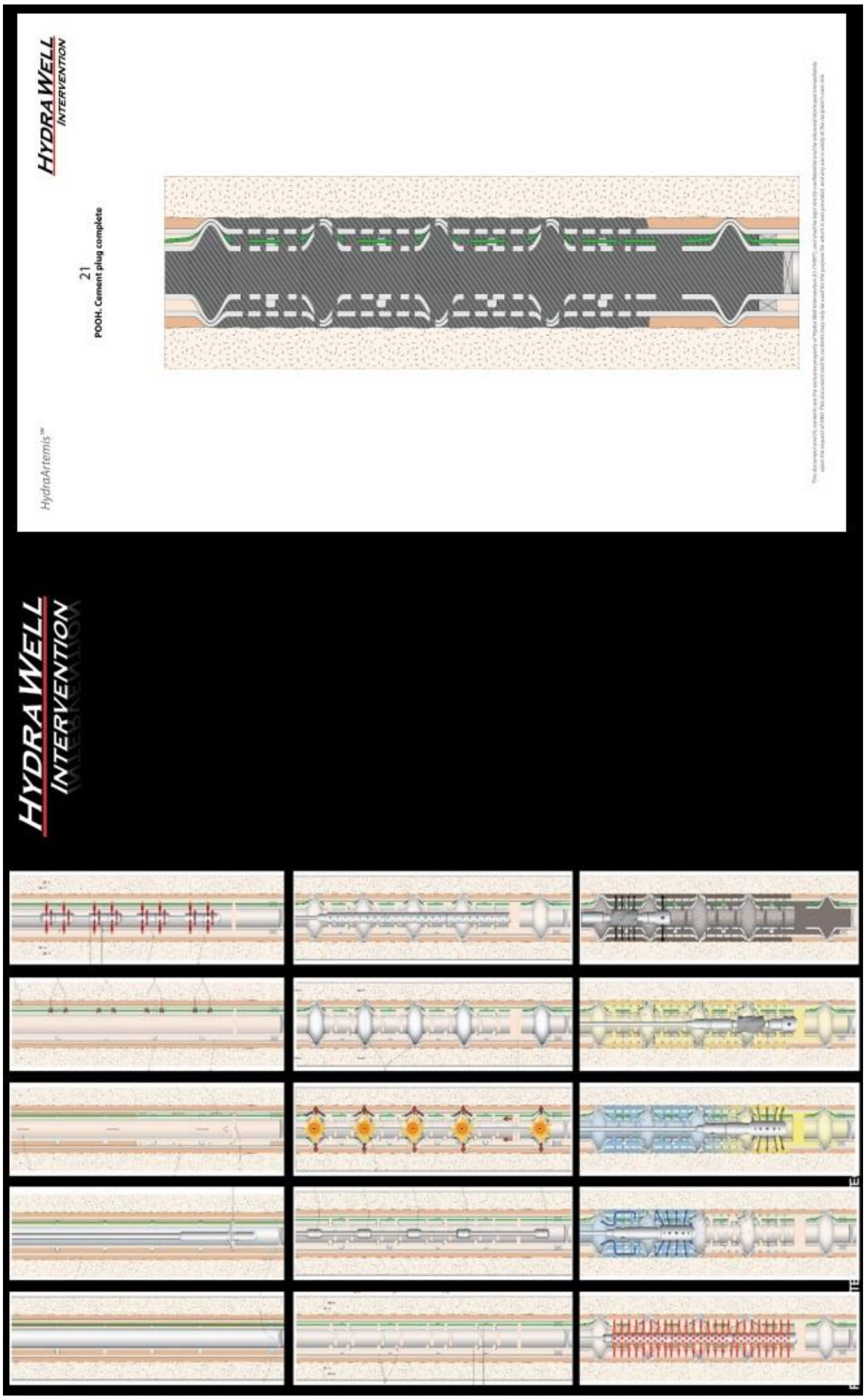
15.3 Appendix C – HydraArtemis



15.4 Appendix D – Work Packages

This table is a presentation of the different work packages associated with different phases of a subsea well P&A operation. The P&A operation is fulfilled by combining the different work packages and by repeating some of them if required. The green cells indicates the current practice, the yellow cells indicates that the technology/method exists and the red cells indicates that there is no technology provided. The table is a comparison between a semi-submersible and a RLWI vessel.

Activity	Unit							
	Semisubmersible rig							
Phase 0 - Preparatory Work for P&A	Kill well - VXT/HXT	Logging	Punch/Cut production tubing.	Install deep/shallow set plugs	Circulate tubing and A-annuls	Retrieve VXT		
P&A Phase 1 - Reservoir Abandonment	Nipple up & down BOP	Pull tubing	Cut & retrieve casing	Section milling	Perforate, wash & cement	Retrieve HXT	Logging	Wash & set cement plug
P&A Phase 2 - Intermediate Abandonment	Cut & retrieve casing	Logging	Wash & set cement plug	SWAT/WASP - one annulus	SWAT/WASP - Two annulus			
P&A Phase 3 - Wellhead and Conductor Removal	Abrasive cutting	Mechanical cutting	Removal with explosives (Must be approved by PSA)					
Activity	RLWI Vessel							
Phase 0 - Preparatory Work for P&A	Kill well - VXT/HXT	Punch/Cut production tubing	Install deep/shallow set plugs	Logging	Circulate tubing and A-annulus	Logging	Retrieve VXT	Nipple up & down RLWI Stack (w/WCP)
P&A Phase 1 - Reservoir Abandonment	Retrieve HXT	Nipple up & down RLWI Stack/RLCT Stack/SSD	Pull tubing	Wash & set cement plug	Logging	Perforate, wash & cement (CT)	Cut & retrieve casing	Section milling
P&A Phase 2 - Intermediate Abandonment	Cut & retrieve casing	Logging	Wash & Set cement plug	SWAT/WASP/CAT - one annulus	SWAT/WASP/CAT - two annulus			
P&A Phase 3 - Wellhead and Conductor Removal	Abrasive cutting	Mechanical cutting	Removal with explosives (Must be approved by PSA)					