Universitetet i Stavanger

FACULTY OF SCIENCE AND TECHNOLOGY

MASTER'S THESIS

Study program/Specialization: Master of Science in Petroleum Technology Well Engineering	Spring semester, 2017 Open
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Thesis title: Utilization of Purpose-Built Jack-Up Units for Plug and Abandonment Operations	
Credit (ECTS): 30	
Key words: Plug & Abandonment Purpose-Built Vessels Light Well Operations Coiled Tubing	Pages: 70 + Enclosures: 4 Stavanger, 15/06-2017 Date/Year

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Abstract

The oil and gas industry working on the Norwegian continental shelf have the past years increased the focus on decommissioning of fields, after several years with attention to increase and enhance oil recovery. The topic plug and abandonment has been well-recognized by the Norwegian authorities, the oil and gas industry and the public media due to the expected cost which will affect both Norwegian taxpayers, licence partners and operators working on the shelf. There has been a large emphasis to cut these cost, where companies are currently developing new solutions to enhance the process to plug and abandon wells. The concept “rig-less” P&A have been expressed as a futuristic goal from “Norwegian Oil and Gas” in their roadmap for new P&A technologies [1].

This thesis investigates performance differences of a purpose-built P&A unit based on previous performed well abandonments with regular jack-up rigs. The unit is designed to be a cost-efficient rig alternative to regular jack-up rigs, which is designed to perform heavier well operations, such as drilling. The study focus on P&A operations of offshore platform wells, and includes estimates of cost differences between the chosen concept and a standard jack-up rig. Variables like tripping speed, pumping capacities, tubing retrieval efficiency and durations to mobilize equipment will determine the performance of the unit. A lot of the time spent during a P&A operation is related to tripping of pipe. Wireline and coiled tubing are equipment that reduce tripping time, but will the relationship between cost and performance improvements be satisfactory?

The findings of the study indicate that employment of the chosen rig design concept provides better economics in the specific well abandonments used for the comparison. There are several factors which determines if the combination of coiled tubing and wireline yet are the preferred solution. With the “Norwegian Oil and Gas” ambitions to develop more technology to increase rig-less P&A scope, this combination may be the preferred solution, to cope with the future needs.

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Acknowledgement

I would like to thank Torstein Thomassen, Helge Hustoft and the rest of the team at Dwellop AS for the collaboration and assistance during the study. I would also like to thank Jens Myklebust for introducing me to the company, giving me the opportunity to finish my thesis in an environment of innovation and enthusiasm.

Both the service and operator part of the industry have been very helpful in answering my questions and giving feedback to the study. A thanks goes to AkerBP, Statoil, ConocoPhillips, Welltec, Schlumberger, Baker Hughes, Hydrawell, Maersk Drilling, Ramboll, Wellbarrier AS, Acona AS and APC AS for meetings and information about systems and practices relevant for the study.

Thanks to professors; Jayantha Prasanna Liyanage, Kjell Kåre Fjelde, Mesfin Belayneh Agonafir and Francisco Porturas for advices and feedback throughout the study.

Special thanks to Associate Professor Jan Aage Aasen at the University of Stavanger for supervising me throughout my thesis. You have motivated and inspired me with your enthusiasm for the subject, and guided me with professional feedback based on your specialization and experience. Your ever skepticism and ability to be “The Devil’s Advocate” have contributed to improve the thesis. I wish the best of luck with future work of re-structuring the institute, where we have had several meetings and discussions about the subject.

At last, a special thanks to my family, friends and classmates for motivating me throughout the thesis.

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List of Abbreviations

BOP – Blow out preventer

CT – Coiled tubing

DHSV – Downhole safety valve

DP – Drill pipe

ECD – Equivalent circulation density

FIT – Formation integrity test

ID – Inner diameter

J/U – Jack-up

MD – Measured depth

NCS – Norwegian continental shelf

N/D – Nipple down

NORSOK – “Norsk sokkels konkurransetilsyn”

NPT – Non-productive time

N/U – Nipple up

OD – Outer diameter

P&A – Plug and abandonment

POOH – Pull out of hole

PP&A – Permanent P&A

PSA – Petroleum safety authority

PWC – Perforate, wash and cement

RIH – Run in hole

SB - Setback

SIMOPs – Simultaneous operations

SPS – Special periodic survey

SOW – Scope of work

TCP – Tubing conveyed perforations

TOC – Top of cement

TP&A – Temporary P&A

UWHP – Unmanned wellhead platform

WBE – Well barrier envelope

WI – Well integrity

WL – Wireline

WOB – Weight on bit

WOR – Workover rig

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1. Introduction
1.1. Background for Study

As a result of the challenging period in the oil and gas industry with falling crude oil prices and investment willingness, the offshore rig market is experiencing major challenges after several years of high utilization of the rig fleet with stable high rig rental rates. Thus, the rig owners have been forced to cold stack their units and let go of important personnel. By May 2017 about 50 percent of the jack-up rigs working on the shelf are out of work [2]. Cold stacking of rigs which are heading to costly Special Periodic Survey (SPS) can lead to a dilution of the rig market. In order to ensure that the rig fleet is proportioned to the future need, it is important to consider both the work that is ready today and the work we can anticipate that must be done on the shelf in the future. Awareness of the future needs gives an opportunity to proportion the rig fleet accordingly.

If we are looking at the present scope of work (SOW) that needs to be done on the shelf today, it is mainly drilling, interventions, workovers and plug and abandonment (P&A). Most of today's mobile offshore units working on the shelf are designed to drill and complete wells and consequently the units include large rigs with accordingly crew to service them. In a future perspective, there is one operation that will increasingly need to be performed. Operators working on the shelf are obliged to P&A wells after production or injection has finished. The work can be categorized as lighter rig work, alongside with interventions and workovers. P&A is performed to some extent on the shelf today, but without increasing the activity continuously there are some studies who predicts we will face a "plug-wave" in the next decades.

A BSc study from the University of Stavanger in 2015 established an overview of the remaining P&A work to be done on the NCS [3]. It showed that out of a total 5768 drilled wellbores, 2552 of them remained to be finished and expected the cost of P&A on the NCS to be 571 billion NOKs. Since the Norwegian taxpayers hold 78% of these costs, it should be in everyone’s interest to reduce this number.

If we combine the fact that we in the future might have deficit of drilling rigs on the shelf and that the future workload on the Norwegian continental shelf (NCS) involves increased amount of lighter well operations, it is reasonable to ask whether we need to expand our toolbox. To be able to cut national expenses we need to find cheaper and more efficient solutions. For subsea wells there have been done a lot to include purpose-built ships and units to perform lighter well operations. When it comes to platform wells, the story is different. “Norwegian Oil and Gas” highlighted future rig-less P&A as one of their ultimate goals in their “Roadmap for Future P&A Technologies”, presented at the annual P&A seminar in Stavanger, autumn 2016 [1]. The service industry is working to realize this goal, but has not progressed far enough yet. Do we utilize the best purposed tool to carry out P&A operations on the NCS today? Is it appropriate to use the heaviest tool to perform easier well operations, and will a purpose-built P&A unit help reduce the cost associated with this work?

1.2. Problem Definition

Will inclusion of a purpose-built P&A unit lead to reduced costs in offshore P&A operations of platform wells?

1.3. Limitations

This study will not focus on new downhole solutions and technology, moreover operational solutions by choosing the best suited equipment to conduct the different operational sequences. The study only investigates P&A operations of offshore platform wells and will rely on the data basis gathered for the duration of past operations. It will use approximations to calculate the differences by selecting one concept over another and make the necessary assumptions to calculate the profitability of the different designs.

1.4. Objective and Structure of Thesis

In order to answer the problem definition, it is necessary to elaborate why P&A must be done and what such an operation involves. A thorough review of the regulations and operational procedures for well abandonment will be performed, before the analysis of the study is conducted. To be able to perform a detailed evaluation of the issue, it is necessary to review a concept for a purpose-built unit for P&A operations, and the tools related to this concept. The study attempts to perform the necessary calculations to justify the use of the most suitable tool for each operational sequence based on the concept. By using real operational data from two previous well abandonments, the study will compare the rig concepts performance up against a regular jack-up rig. Three designs of the selected concept will be presented to compare the advantages of using different tools to perform the operations. The study ultimately analyses duration differences between the chosen candidates, but to be able to put the potential savings in perspective, related rental rates and costs have been included.

The thesis is divided to ten chapters with sub-sections. The following main chapters are included to the thesis:

- Chapter 1 reviews the background and defines the problem and limitations of the study.
- Chapter 2 gives an introduction to P&A operational regulations, well barrier philosophies and methods of well barrier establishment.
- Chapter 3 is a study of the chosen concept for the thesis. It reviews the capacity, scope of work and limitations of the design.
- Chapter 4 gives a review of usage of the different tools, and the technical limitations of coiled tubing.
- Chapter 5 describes the methodology of the thesis and reviews the basis of the results.
- Chapter 6 and 7 deliver the analyse and results, and discuss the market potential based on the results
- Chapter 8 is concluding the study and give recommendations for future work.
- Chapter 9 includes four appendices
- Chapter 10 is the reference list for the thesis

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2. Permanent P&A of Wells

This chapter gives an introduction to the Norwegian regulation and guidelines, well barrier establishment methodology and the operational phases for permanent well abandonment. This will provide a basis for understanding how the offshore operation in the analysis is performed. The chapter is based on the author's bachelor thesis, but has been re-structured to suit the new problem definition [3].

P&A is the process to install permanent barriers to seal of a well or a section of a well to prevent cross-flow between different formations or migration of hydrocarbons to surface with an eternal perspective. NORSOK D-010 requires; "*Permanent abandoned wells shall be plugged with an eternal perspective taking into account the effects of any foreseeable chemical or geological processes. The eternal perspective with regards to re-charge of formation pressure shall be verified and documented" [4]*.

An oil and gas well goes through different phases throughout life. Towards the end, the cost of recovering the liquids reaches the point at which the operator must cut down production. The well regarded no longer considered economically viable and the operator faces three options:

- **Slot recovery** is the term used if an operator for some reason discovers the well to be profitable from a different wellbore and wish to re-use the slot. This can be achieved by plugging back the wellbore, set a whip stock and drill a sidetrack inside the mother bore.
- If the intention is to re-enter the bore after a while, the operator must **Temporary Plug and Abandon** (TP&A) the well, by securing the wellbore from leaking to surface. Control equipment will often be in place, until a new plan is decided.
- If the operator concludes a well as finished with no intention of re-entering, they must close it by **Permanently Plug and Abandon** (PP&A) the well. Operators are obliged to leave the well in a condition, which protects the environment from pollution.

PP&A of wells are only one of several elements operators are obliged to undertake during decommissioning of an offshore facility. Decommissioning of offshore fields depends on whether the field is based subsea or top-site, but in common that all structures and infrastructures associated to the field should be dismantled and permanently removed from the site. This study will focus on permanent abandonment of platform wells and will not include related decommissioning activities. Thus, these costs will not be included in the value proposition.

2.1. Introduction to NCS Regulations and Guidelines – NORSOK

All operations on the NCS must be conducted in accordance with the Petroleum Act to satisfy adequate safety. The need for decommissioning and specific P&A operations is given by this act which is regulated by the PSA who refers to NORSOK D-010 rev. 4. "Norsk sokkels konkurransetilsyn" (NORSOK) is a guideline to reduce time and costs regarding constructions and operations of petroleum installations on the NCS. The foundation of this study will rely on NORSOK D-010, which is presently developed by the Petroleum Safety Authority (PSA) and publicized by Standard Norway. NORSOK D-010 covers the minimum requirements and guidelines for well design, planning and well operations, with regards to P&A operations.

2.1.1. Well Integrity

Well integrity (WI) is defined in NORSOK D-010 as "*an application of technical, operational and organizational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well*" [4]. WI is the term for having barriers in place, to understand and respect them. They must be tested, verified, monitored and maintained throughout the lifetime of the well. The life cycle aspect starts with the initial design and ends when the well has been permanently plugged and abandoned. All activities during the life cycle of the well shall be carried out in a safe manner. The standard focuses on establishing well barriers by use of well barrier elements (WBEs), their acceptance criteria, their use and monitoring of integrity during their life cycle [4].

The well barriers shall be designed, manufactured and installed to withstand all loads they may be exposed to and to maintain their function throughout the life cycle of the well [5]. Operators are obliged to ensure equipment is used in accordance with the standards given in NORSOK D-010 when designing the abandonment phase.

One of the main objectives of WI evaluation is to identify potential hazards that can occur during the different operational phases. Integrity problems can be a result of formation–induced problems like pressure, temperature, formation fluid, which again can lead to erosion, corrosion and degradation. It can be operational induced problems, such as operating the well and equipment above the design limits, lack of maintenance, installation failures, equipment failures and failures related to testing and verification. Leakage is the main concern during the P&A phase, and operational changes can affect the pressure and temperature level in the well when setting a plug [5]. It is important to have a contingency plan in case of a barrier failure. Section 4 in NORSOK D-010 gives guidance and requirements regarding WI.

2.1.2. Requirements for Well Barriers

The main goal for a P&A operation is to isolate zones with permanent barriers where there is a risk of flow from a source. A barrier is established to prevent flow from source to surface or another formation. A primary barrier is the first object to prevent unintentionally flow from a source and then a secondary barrier is established to back-up the primary barrier in case of failure [4]. It is of great importance to differentiate between well barriers and WBEs. A well barrier consists of one or several independent WBEs that prevents fluids or gases from flowing unintentionally from the formation to the surface, or into another formation. The WBEs creates these “objects” [3].

The facilities regulations §48 [6] states, *“When a well is temporarily or permanent 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”.* It is crucial is to establish a well barrier envelope, which consists of several WBEs. Well barrier envelopes are important to maintain WI for all activities (e.g. during drilling where a casing would be a barrier that prevents loss of fluid and pressure). Nevertheless, it is necessary to establish well barrier envelopes during testing, completion, production and in P&A operations where the focus is on permanent abandonment of wells/wellbores.

NORSOK D-010 describes four different well barriers with individually objectives [4]:

- Primary well barrier: To isolate a source of inflow, formation with normal pressure or over-pressured/impermeable formation from surface/seabed.
- Secondary well barrier: Back-up to the primary well barrier, against a source inflow.
- Cross flow well barrier: To prevent flow between formations (where cross flow is not acceptable). May also function as primary well barrier for the reservoir below.
- Open-hole to surface well barrier: To permanently isolate flow conduits from exposed formation(s) to surface after casing(s) are cut and retrieved and contain environmentally harmful fluids. The exposed formation can be over-pressured with no source of inflow. No hydrocarbons present.

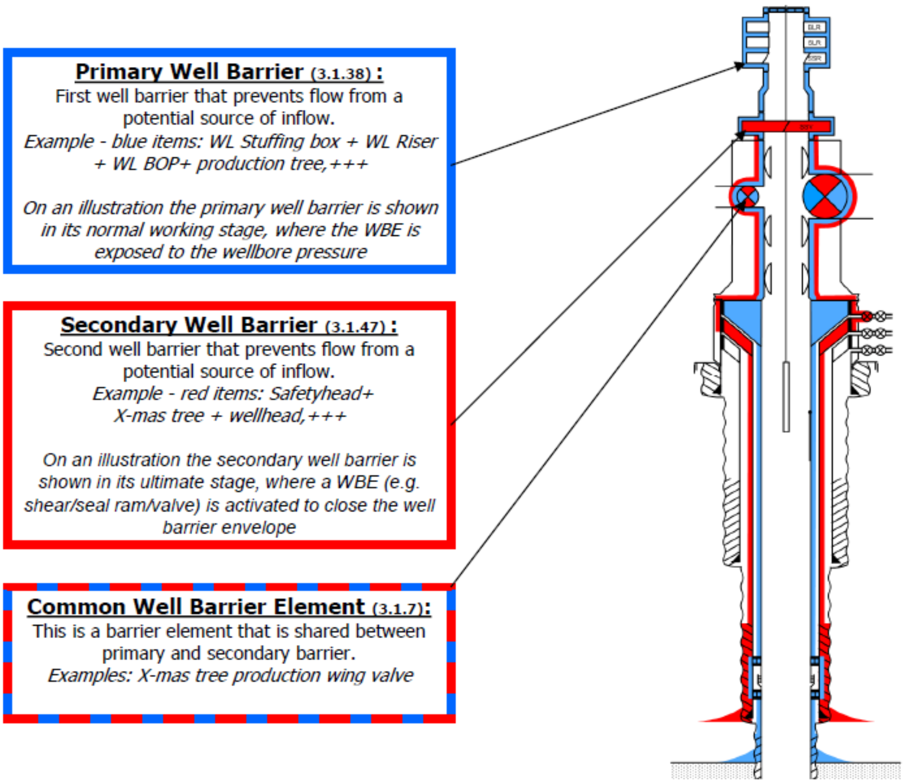

Figure 1 - Schematic of a primary and secondary well barrier envelope [7]

In Figure 1, the primary well barriers are marked as blue. There are several different WBEs which defines the primary well barrier. It is important that all WBEs create an envelope. This envelope shall seal off all possible leaks.

The primary and secondary barrier envelope should as far as possible be independent of each other with no common WBE. For some wellbores, these two well barriers may not be sufficient and a combination of several well barriers has to be considered. The number of well barriers necessary will always depend on the formation [8].

- One barrier:
  - Permeable formation with normal or less pressure
  - Impermeable formation with overpressure
  - Undesirable cross flow between formation zones
- Two barriers:
  - Permeable formation with overpressure
  - Permeable formation with hydrocarbons present

A conventional well barrier consists of Portland cement or a mechanical plug (bridge plug, also called EZSV) depending on the purpose; temporary or permanent abandoned. A well barrier should be installed as close as possible to the potential source of inflow[4]. Figure 2 illustrates the concept of two independent well barrier envelopes in a "hat over hat" principle. The secondary barrier envelope, marked in red, is designed to be able to avoid disaster if the first barrier envelope should fail.

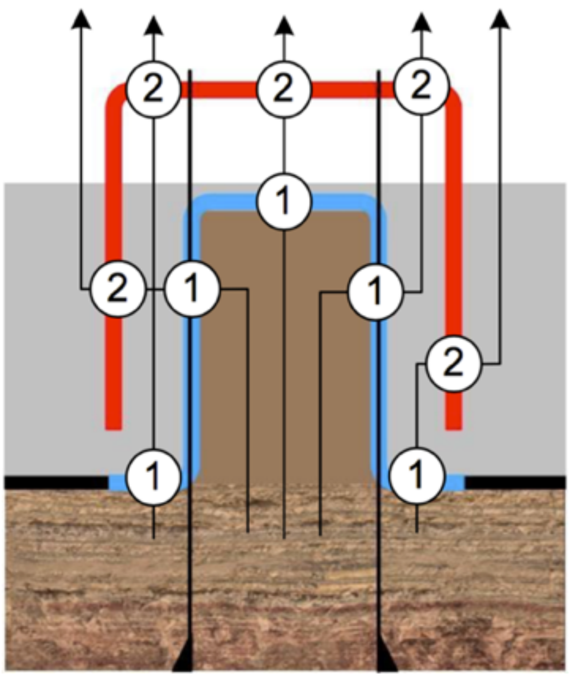

Figure 2 - Hat over hat well barrier envelope principle

2.1.2.1. Well Barrier Criteria

In a PP&A operation, all well barriers shall be sufficiently plugged. Hence, no leaks shall occur and the well barrier shall be plugged with an eternal perspective. NORSOK D-010 require all permanent well barriers to extend the full cross-section of the well, including all annuli and seal both vertically and horizontally as illustrated in Figure 3. The well barrier shall be placed in an impermeable formation with sufficient formation integrity for the maximum anticipated pressure.

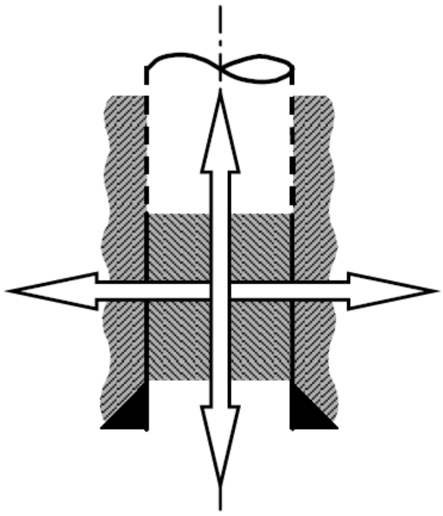

Figure 3 - Illustration of an acceptable cross-sectional well barrier [4]

There are a variety of requirements regarding an acceptable permanent barrier in P&A operations. According to NORSOK D-010 there are some requirements to be considered before a P&A operation:

- The suitability of the selected plugging materials shall be verified and documented. Degradation of the casing should be considered.
- Removal of downhole equipment is required when this can cause loss of WI. Control lines and cables shall not form part of a permanent well barrier.

A permanent well barrier should hold the following characteristics:

- Provide long term integrity (eternal perspective)
- Impermeable
- Non-shrinking
- Able to withstand mechanical loads/impacts

- Resistant to chemicals/substances (H_2S, CO_2 and hydrocarbons)
- Ensure bonding to steel
- Not harmful to the steel tubulars integrity

All well barriers should be independent of each other. If an operator decides to have common WBEs, a risk analysis shall be performed and documented to maintain adequate safety.

2.1.2.2. WBE Acceptance Criteria

A well barrier is achieved by one or several WBEs that establish the well barrier envelope. Each WBE have an important task to seal of any leaks and it is important to verify these WBEs to be able to endure their task for eternity. Several criteria need to be met in order to accept a WBE as a part of a well barrier, known as WBE acceptance criteria [3]. The WBE acceptance criteria for casing, casing cement and cement plug are the main area of interest in a P&A operation. Casing is a WBE with certain acceptance criteria and is an important factor in the initial well design. Casing can lead to unintentional flow due to a possible leak path between casing and cement during permanent P&A where casing is present [4]. External and internal WBE is differentiated by their requirements when conducting a PP&A operation.

2.1.2.2.1. Positioning Requirements

The number of well barriers in a wellbore depends on the number of reservoir zones, sources of inflow, pressures and permeability of formations. There should be at least one permanent well barrier between potential source of inflow and surface [3]. If the well barrier should be set at a shallower depth due to its complexity, the requirement states the estimated formation fracture pressure at the base of the plug to be higher than the potential internal pressure. This applies for the primary and secondary barrier. The point of interest is where the internal pressure is less than the formation fracture pressure and the plugs cannot be set shallower than this point due to overpressure beneath the plug. The potential internal pressure is the reservoir pressure minus the reservoir fluid hydrostatic pressure. Even though NORSOK D-010 does not define which reservoir pressure to use, initially reservoir pressure can be regarded as a rule of thumb.

2.1.2.2.2. Internal WBE Requirements

The internal WBE will be the last installation during establishment of a single cross-sectional barrier. This plug shall be positioned over the entire interval where there is verified external WBE (e.g. casing cement). The plug shall be minimum 50 m if set on a EZSV or cement as a foundation. Otherwise, see the requirements and guidelines in NORSOK D-010 section 15, EAC table 24. Some of the requirements are:

- Open hole cement plugs shall be 100 mMD with minimum 50 mMD above any source of inflow/leakage point.
- A plug in transition from open hole to casing should extend at least 50 mMD above and below casing shoe.
- Cased hole cement plugs shall be 50 mMD if set on a mechanical plug/cement plug as foundation. Otherwise 100 mMD.
- A casing/liner shall have a shoe track plug with a 25 m MD length.

2.1.2.2.3. Verification of Internal WBE

The cement plug needs to be verified to ensure an adequately cement job and that all requirements in NORSOK D-010 is followed. The requirements for plug verification are:

- Inflow test – cased hole plugs should be tested either in the direction of flow or from above
  - An inflow test is performed to ensure no leakage. The hydrostatic pressure is reduced above the cement plug by bleeding of the shut in pressure or by displacing the wellbore fluid to a lighter fluid. The pressure gauges are monitored to see if the pressure remains constant.
- Pressure test – Increase the pressure above the plug using pumps
  - Shall be 70 bar above estimated leak off pressure below casing/potential leak path, or 35 bar for open-hole to surface plugs.
  - Shall 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.

These tests can reveal if there are any leaks above the plug and insufficient cement exposure over the perforation. Nevertheless, it will not indicate the overall integrity of the entire cement plug.

To verify the top of cement (TOC) and to test the integrity of the cement plug, a work string or tool string is lowered until it lands on the top of the cement plug. The tool string can now tag and confirm the TOC. At the same time, the tool string will perform a load test by applying weight onto the plug. If the string remains at the same depth and the weight on bit readings increase as more weight is applied, the plug is solid, set and approved [9].

2.1.2.2.4. External WBE

The external WBE is the cement outside the casing (e.g. casing cement) which shall be verified to ensure a vertical and horizontal seal. To be able to verify two casings with annulus cement, old logs should be used since it is not possible to log through multiple casings. The purpose of the external WBE is to provide a continuous, permanent and impermeable hydraulic seal along the wellbore to prevent flow of formation fluids or resist pressure developments [4].

NORSOK D-010 has certain requirements and guidelines regarding the external WBE. The acceptance criteria and verification are:

- The interval shall have formation integrity
- Logging of casing cement shall be performed for critical cement jobs and for permanent abandonment where the same casing element is a part of the primary and secondary well barriers.
- If sustained casing pressure is observed, the seal of the casing cement shall be re-verified.
- The requirement for an external WBE is 50 m with formation integrity at the base of the interval.
- If the casing cement is verified by logging, a minimum of 30 m interval with acceptable bonding is required to act as a permanent external WBE.

2.1.2.2.5. Formation as a Well Barrier

Good bonding in annuli can be experienced even though it is high above imagined TOC or at a location with no cement. This is a phenomenon where the formation has moved into the wellbore and created a natural external barrier.

In an abandonment phase this natural external barrier can help reduce both time and costs, but verification is required if it shall be used as an external barrier. The following requirements from NORSOK D-010 EAC table 51 must be fulfilled [4]:

- The formation shall be impermeable with no flow potential.
- The formation integrity shall exceed the maximum wellbore pressure induced.
- The formation shall bond directly to the casing/liner annulus material (e.g. casing cement) or plugs in the wellbore.
- The formation shall be selected so it will not be affected by change in reservoir pressure over time.
- If the formation is bonding directly to the casing, then the requirements in EAC table 52 “Creeping formation” shall also apply.
    - The element shall be capable of providing an eternal hydraulic pressure seal
    - The minimum cumulative formation interval shall be 50 m MD with 360 degrees of qualified bonding.
    - The minimum formation stress at the base of the element shall be sufficient to withstand the maximum pressure that could be applied.
    - The element shall be able to withstand maximum differential pressure.
    - Two independent logging tools shall be applied and provide azimuthal data to be interpreted and verified by qualified personnel.

The formation will be qualified as an external barrier if logging, pressure and formation integrity test (FIT) are verified.

2.2. Well Barrier Establishment

As the wellbore has been plugged and abandoned, the reservoir will strive to achieve the initial pressure when using a conservative estimate for the pressure development. Nevertheless, it is important ensure barriers to withstand both present and future forces from the reservoir. The process to P&A a well can be complex due to all the variable well conditions. A good overview of the respective well conditions, and how it is constructed is essential to be able to do the work proper and safe.

2.2.1. Sufficient Annular Barriers

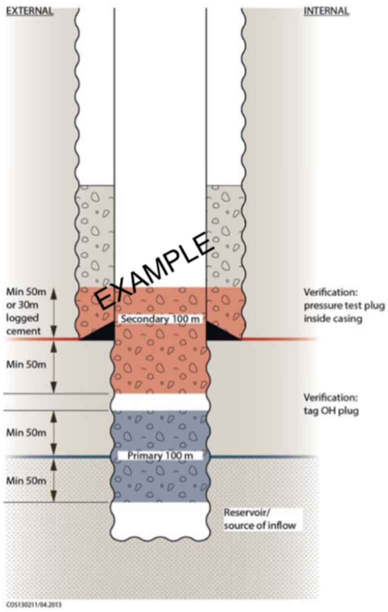

Figure 4 – NORSOK D-010 (Fig 9.6.61) – PP&A, open hole and inside casing plugs [4]

An open hole cement plug consists of a hydraulic cement, normally a Portland cement. The wellbore should be cleaned to ensure sufficient bonding.

Different scenarios:

- Open-hole formation plug (also applies in situation where the casing is cut and pulled)
  - Cross-sectional cement plug bonding to the formation
- Internal cement plug
  - Cross-sectional cement plug bonding to the inside of the casing (Requires verified barrier outside of the casing).

The most common method to perform an open-hole or internal 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 base set during the first phase of the abandonment. A secondary cement plug is in some cases set upon a primary cement plug.

2.2.2. Insufficient Annular Barrier

Insufficient annular barriers result from poor casing cement, lack of creeping shale or leaking barrier elements. To be able to re-establish and provide a cross-sectional barrier there are several methods available. The two next chapters will review some of the present conventional and unconventional methods of well barrier establishment.

2.2.2.1. Conventional Methods

Casing/Tubing Removal

Casing string are removed for different reasons, but mainly to ensure integrity of each different section. The barrier can be set into virgin formation by removing casing(s). Pressure differentials and possible leak paths will therefore be of no concern due to their removal. There are several factors that can be challenging when pulling a string out of the well (e.g. collapsed formation, settled mud particles, or traces of cement due to poor cementing job) [10].

Sometimes a casing string needs 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 unfortunately not been developed yet.

The casing string is cut with a designated tool for the respective job and pulled out of the hole. During such a job, several problems can occur. The transition between annulus cement and fluid in annulus need to be located referred to as the free point. It can be impossible to pull the casing string out of the hole if the executed cut is within the annulus cement zone. Casing and tubing removal make up much of the time spent during a P&A operation. The industry has ambitions to conduct P&A operations with the tubing left in the well in the future.

Section Milling

In some cases, the casing string might not be possible to pull. Section milling is the preferred method to create a cross-sectional barrier towards direct exposed formation where the annular material disqualifies as an annular barrier [11]. The required section of casing string is milled out with a designated tool. This will expose the formation which needs to be 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 consideration [9]:

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

Milling creates metal cuttings, called swarf, and can be stuck as it is transported to the surface, and is considered the main challenge with section milling. To be able to lift the swarf to the surface it requires a dense and viscous fluid, and will combined with a high fluid-velocity cause high equivalent circulation density (ECD). This may cause the formation to fracture and result in loss of well fluids.

When swarf get stuck, referred to as “bird nest”, they can restrict the flow and section milling tools can get stuck during retrieval. Swarf will often accumulate in areas with reduced annular velocity, often in liner hanger and blow out preventer (BOP). It is important to clean the wellbore to remove all swarf and debris, especially in the pressure control equipment after milling out a section.

2.2.2.2. Unconventional Methods

There has not been a significant change in the technology and methodology used in P&A operations since the beginning of developments on the NCS. It has been a large focus to develop technology to improve drilling and enhance recovery of our fields. Most of today's P&A technology was developed in the 20th century and are based on large mechanical operations to recover, or remove tubular to be able to access the formation and establish a proper barrier. During the past years, companies have done more research to find new materials, methods and tools to be able to improve permanent well abandonment. Perforate, wash and cement (PWC®) system will be included in the analysis, and thus elaborated in the next section.

Perforate, Wash and Cement [12]

Lately, a new method to achieve verified barriers has been presented. The PWC system by Hydrawell is an alternative to the conventional method of section milling. This system perforates and washes the selected casing or liner section before cementing the encircling annulus. By performing such an operation, a permanent rock-to-rock barrier will be established.

The tool consists of a tubing conveyed perforation (TCP) gun located in the bottom of the tool and rubber cups with circulation ports in between. A cement stinger is located at the top of the tool.

Figure 5 - Illustration of the washing process performed by the HydraWash tool [12]

It is always wise to conduct a logging run to determine where the best-suited intervals are situated. Hence, where the minimum amount of cement is located. After the perforation is performed, the 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 avoid contamination of fluids. The cement is then injected and the cement stinger is pulled out slowly simultaneously. A tool called the Archimedes rotates to force more cement through the perforations and ensures a uniform cement plug in the cross-section.

Another invention by Hydrawell called the HydraHemera, is a system allowing the operator to perform PWC® behind two casings. The HydroKratos is attached to the bottom of the TCP guns to ensure a solid annulus base for the annulus cement barrier. Figure 6 illustrates the job performed by HydroKratos.

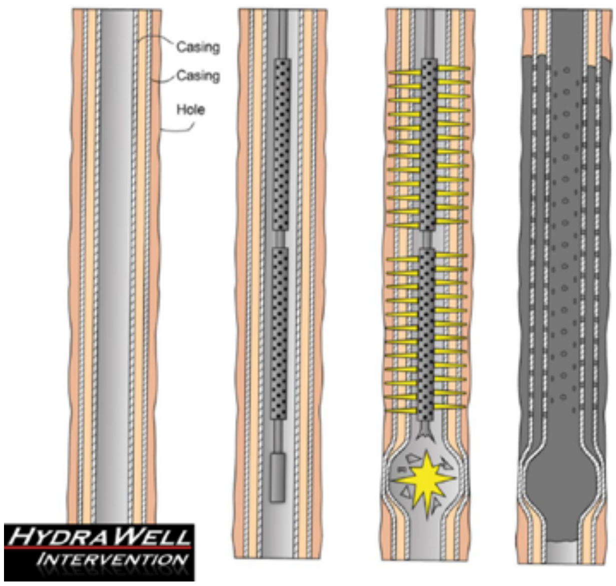

Figure 6 - Illustration of the HydroKratos making a base for PWC® with HydraHemera [12]

The TCP guns are pulled out of hole and replaced with the HydraHemera system, which is illustrated in Figure 7. The HydraHemera system consist of a bullnose for circulation in the bottom, a jetting tool with angled nozzles for washing behind both casings, a cementing tool and the Archimedes cementing tool for centralization and proper displacement of cement in the annuli. The washing and cementing job have great similarities as the HydraWash and will therefore not be described. Nevertheless, The HydraHemera is often preferred since it can handle more cement particles than the HydraWash.

Figure 7 - Illustration of the washing process performed with HydraHemera [12]

Benefits by using the PWC® method:

- No swarf.
- After perforating the section and gas is presented, gas can be circulated to the surface in a safe manner
- Easy cleaning process
- Easy to adjust washing parameters to avoid fluid loss

Challenges:

- Important to avoid fracturing the formation → loss of washing fluid → poor hole cleaning
- Lost mud can return at a later stage and contaminate the cement
- Deviated sections → debris settles around the pipe on the low side → solution: using a swivel right above the disconnecting section to be able to rotate the string so the particles cannot settle around the pipe.

2.3. Operational phases for P&A

It is impossible to standardize P&A operations since wells are drilled in different areas and stratigraphy. Local variations in formations and overburden properties require the operators to prepare a specific program for each well. It can be a challenging task to plan the operations so it meets regulations and quality requirements. There are several factors that will determine how P&A operations should be executed; well conditions, cement quality, number of potential influxes, well inclination, sidetracks and more. The design basis for an abandonment operation is given in NORSOK D-010 [4];

a) Well configurations (original and present) including depths and specifications of formations, which are sources of inflow, casing strings, casing cement, wellbores, sidetracks.
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, with reservoir fluids and pressures (initial, present and in an eternal perspective).
c) Logs, data and information from cementing operations.
d) Formations with suitable WBE properties (e.g. strength, impermeability, absence of fractures and faulting).
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill, H_2S, CO_2, hydrates, benzene or similar issues.

According to UK Oil & Gas – Guideline on Well Abandonment Cost Estimation the P&A operation of any well can be divided into three phases, reflecting the work-scope and equipment required to conduct the operation [13]. Occasionally the different phases are conducted with different units and equipment for each phase, especially for subsea wells. This is where the study tries to challenge the standard, by striving to always use the most suitable equipment for every operational sequence within each phase. The operation can thus still be divided into three phases, but it does not necessary reflect which type of equipment that is used to conduct the respective phase [13].

Phase 1 – Reservoir Abandonment

"Primary and secondary permanent barriers set to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. Complete when the reservoir is fully isolated from the wellbore." A part of phase one is often referred to as off-line work. During this initiating operation to the phase the original downhole safety valve (DHSV) is retrieved, the well is killed, a deep-set mechanical plug is run, tubing is cut, annulus is displaced to brine and a new DHSV is installed. This work is conducted with wireline (WL).

Phase 2 – Intermediate Abandonment

"Includes: 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."

Phase 3 – Wellhead and Conductor Removal

"Includes; retrieval of wellhead, conductor, shallow cuts of casing string, and cement filling of craters. Complete when no further operations required on the well."

These three phases are not included as presented in the analysis, but as sequences of the different phases. Phase 3 for platform wells are conducted after all the wells within the platform has conducted phase 1 and 2. These two phases are most time consuming, and will be divided into sequences for the analysis.

Figure 8 - Photo of a retrieved subsea wellhead [14]

3. Concept study – DWP550-PA

3.1. General

The purpose of this section is to outline the design, equipment and capabilities of the designed purpose-built P&A and heavy lift jack up unit, hereafter named as DWP. The unit design includes an integrated Dwellop workover rig (WOR) on a cantilever intended for installation on a Zentech R-550D jack-up rig. The described design and planned equipment is a company proposal of design and will be optimized during a project phase. The documentation provided for the next chapter is based on Dwellop internal documents and technical specifications [15].

The complete unit includes hull, legs, spud cans, deckhouse, accommodation, jacking structures, cantilever, WOR, helideck, machinery and cranes. DWP shall be classed by DNV-GL and comply with Petroleum Safety Authority of Norway and Health and Safety Executives of UK. The Heavy Lift Crane will have a separate approval regime. Figure 9 illustrates DWP deployed besides an Unmanned Wellhead Platform (UWHP).

Figure 9 - DWP Self-Elevating Plug & Abandonment and Heavy Lift Crane Jack-Up Unit

3.2. Potential SOW / Operational Capabilities

DWP are designed to conduct the following services:

- Recompletion
- Side-tracks
- ESP change outs
- Clean out of existing casing/tubing
- Milling operations
- Perforation
- Wire line work through rig
- Coiled tubing work through rig
- Cementing
- Plug and abandonment: Including cutting and pulling of conductor/casing/tubing, setting cement plugs and remove X-mas tree
- Drilling up to 15 000 ft.

3.2.1. Platform Wells

The unit is designed to conduct work on offshore platform wells and are destined for operation in the North Sea area in water depths to a maximum of 94 m and well deck elevation of maximum 135 m. Typical platforms within the scope of DWP are platforms without functional derricks. This can either be old platforms with decommissioned derricks or UWHP. The latter is a development concept where the main driver has been to find a cost- and production-efficient solution that offers similar functionality and robustness as a subsea development. Historically, UWHPs have been designed in different variations; from simple dry wellhead installations to more advanced installations with processing equipment, shelter and helicopter deck etc. The platforms are generally steel jacket supported fixed installations, but in a few cases, also concrete gravity based structures have been used as the support structure. The concept has been developed on the NCS and are under consideration in several licenses and developments such as redevelopment of BPs Valhall [16].

3.2.2. Subsea

DWP will also be able to conduct subsea operations. The high-pressure riser and BOP can be tensioned towards the cantilever structure from a “Texas deck”. BOP and riser will be handled as a normal operation, with the riser being lifted through the well centre by top drive and lifting system.

3.3. Equipment

This section will include the features of DWP which differentiates it from a regular jack-up rig (J/U), and can give it an advantage during P&A operations. Specifications regards the equipment can be found in Appendix A [15].

3.3.1. Extended Cantilever

The unit has a skidding system allowing the complete cantilever to be skidded in/out and transverse on the outer part of the cantilever. The combination of a scaled down derrick and reinforced cantilever allows longitudinal skidding of 120 ft, the longest J/U cantilever reach on the market today. Longitudinal reach for regular J/Us is between 60-80 ft. The second largest cantilever working offshore is the new built “Maersk Invincible” with a reach of 110 ft. The transverse skidding will be done at the drill floor area on the cantilever front end and will be +/- 5.5 meters. Longitudinal reach has lately been addressed by operators with regards to P&A operations. Some platforms are designed in such way that it can be impossible to enter it from more than one direction. The platforms weren’t necessary designed this way initially, but as a result of redevelopments with new subsea grids and pipes to the platforms, placement of J/U units to perform work on the platform may be limited. This leads to a desire of long cantilevers to be able to reach all wells within the platform. The DWP cantilever consists of four main areas:

- The cantilever structure and top deck area with equipment
- The drill floor with derrick and equipment
- Inside cantilever with mud return system shakers and flow line, HPU`s and LER containers.
- Inside of the hull; consisting mud system pumps, pits, mixing and storage tanks

Figure 10 - Skidding system with transverse skidding of drill floor

3.3.2. Easy Access Coiled Tubing (CT)

The WOR can be prepared for CT and WL operations. Coiled tubing equipment can be added upon request, including reel, jacking frame and skidding system. The interface to CT equipment can be a part of the cantilever design including interfaces for electrical power, hydraulic and skidding system with park position on drill floor. Details of this interface have been evaluated during the early stage of engineering with focus on strengthening of the drill floor and cantilever to accommodate the CT equipment.

Figure 11 – DWP CT design

The CT reel can be stationary located either on the jack up main deck or on the pipe deck at the back of the cantilever, as in Figure 11. The drill floor can accommodate the DWP jacking frame for safe handling and skidding of the CT injector for such operations. During CT operations, the jacking frame with injector is installed above the well centre. After CT operations are completed, the jacking frame can be skidded to parking position on the drill floor with the coil stabbed for future operations. This system changes the game of CT operations, allowing the operator to change from regular DP to CT in minimum time, without the need to lift heavy equipment, often limited by weather conditions. This system lowers the threshold to use CT in operations where it is suitable, without the issue of wasting time to mob/demob the equipment.

3.3.3. Wireline Operations

The DWP derrick is an open solution, not fitted with a regular “V-door”, enabling easy deployment of equipment to the drill floor. Installation of WL equipment for well operations can be conducted within the same duration as a regular unit.

In addition to WL drill floor operations, there have been a developed a system to equip the cantilever with a WL overhead crane assembled below the WOR. This enables the option to do simultaneous operations (SIMOPs). While the WOR itself can conduct phase 1 and 2 of a PP&A operation, a separate crew can do off-line work on the next well simultaneously. Usually SIMOPs on the well-deck is conducted with large immobile equipment, and can often get in conflict with the cantilever operations. DWP WL overhead crane makes it possible to perform SIMOPs without getting in conflict with the main operation. The cantilever SIMOPs crane capacity is limited to respectively 20 mT and 5 mT for the main- and handling winch.

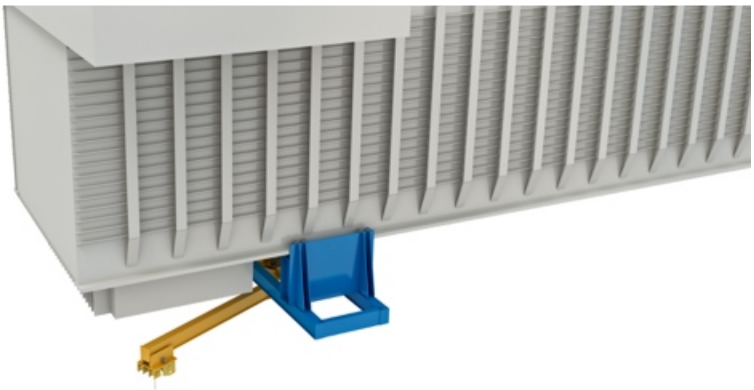

Figure 12 - DWP cantilever SIMOPs crane

3.3.4. Cranes

The unit will be equipped with two standard 70 mT deck cranes on each side of the hull for handling loads from support vessels and internally on the rig. In addition to the deck cranes, the unit will be fitted with one 1 250 mT offshore heavy-lift crane. The crane will be able to manage activities related to commissioning or decommissioning of equipment or structures. It can work subsea down to 94 m water depth. This enables the unit to perform a whole P&A and decommission operation of a platform/template. Structures can be dismantled and lifted on barges/boats for transportation to shore.

3.3.5. Derrick and Drill Floor

In contrast to a conventional drilling derrick, the WOR utilize a mast with a rack and pinion travelling assembly with a drilling top drive. The system includes utility winch, man riding winch, kill/choke/standpipe manifold, iron roughneck and cathead. The derrick can pull a maximum of 250 mT, which should be sufficient for most P&A operations. In demand of heavier lifting, a downhole jack such as Ardyne Downhole Power Tool can be deployed [17].

The machinery on the drill floor, derrick and pipe handling equipment will be controlled from the drillers control cabin (DCC), which includes a drillers chair, operating the top drive with travelling assembly and an assistant drillers chair, operating the pipe handling equipment.

The WOR is designed to improve work environment, handling operations and features extensive use of remote solutions. This reduces the need for hands-on operations and reduces the need for personnel on drill floor. The remote-controlled control system features anti-collision systems for the hoisting system and pipe handling equipment. This improves effectiveness and offers a high operational reliability with a minimum of personnel needed to operate the system.

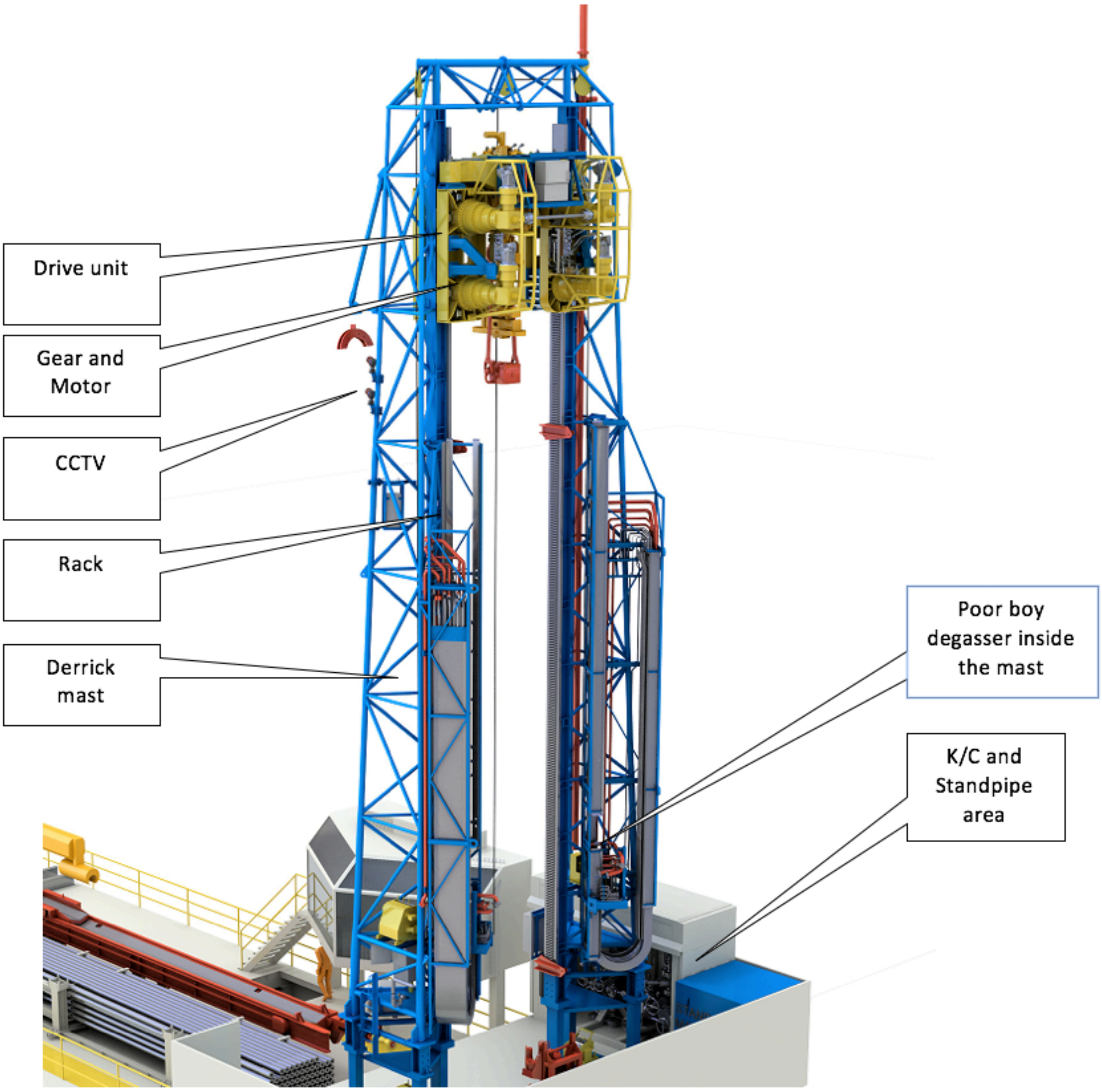

Figure 13 - DWP rack and pinion derrick

With a free height of 17 meters, the rig is not able to store regular drill pipe (DP) stands of three single range 2 DP in the derrick like regular J/Us. The rig use single range 3 DP for heavier operations, which is picked from a horizontal stack on the cantilever by the pipe handling equipment. Table 1 categorize the different dimension ranges of DP.

API Range	Length (ft)
R1	18-22
R2	27-30
R3	38-45

Table 1 - Standard API length range of single drill pipe

3.3.6. Setback

In cases where CT isn't selected as base equipment for DWP, the rig can be fitted with a special designed setback (SB) for the unit. The SB allows vertical storage of 5000m with stands of two R2 DP and is placed where the CT injector usually is located in parked position. This solution enhances tripping operations with DP by 30%, allowing tripping speed up till 1350 ft/hr. By including a setback to the unit, the mast must be raised to increase the free-height of the rig. The unit is either equipped with a drill-pipe setback or CT setup, and cannot be altered without larger modifications.

Figure 14 – DWP drill pipe setback

3.3.7. Pipe Handling Equipment

The pipe handling equipment includes a pipe handling crane and catwalk. The catwalk transport pipe and equipment to the drill floor, whilst pipe is fed by a pipe handling crane. The catwalk unit will handle pipe ranging up to 14" and includes a floor monkey/tail arm to guide the pipe into or out of well centre. The catwalk and pipe handling crane is remote operated from the DCC and are implemented to the anti-collision system. Since the unit is intended to handle single lengths of tubular, retrieval of tubing and casing are performed more efficiently than with a conventional derrick.

3.3.8. Dual Swarf Handling Units

The unit will be equipped with dual swarf handling units, to accommodate the challenges often experienced during milling and section milling of casings and tubing. Dual swarf handling units offers contingency to the operation and will decrease non-productive time (NPT). Milling operations is often limited by the swarf handling unit, which often tends to clog up.

3.3.9. General Equipment

Including the described equipment above, the unit will be fitted with regular drilling equipment to be able to accommodate the operations. A large difference between DWP and a regular unit, is that the quantity of each component is reduced to be able to cut costs. Typical equipment who has been reduced is shale shakers, mud, mixing and transfer pumps, generator sets and pits. The amount of this equipment is designed to achieve a redundant system that will be able to perform the operations that the unit is expected to perform.

3.4. Candidates

Three different candidates/designs of the unit will be included in the analysis. This will add a perspective of how application of different tools with the unit will affect the duration and cost for the operations. The three designs will be differentiated by altering rental rates and durations. The first design is the basic delivery of the unit and will be denoted as DWP-BC (Base Case). This design is illustrated in Figure 13, and will not include any additional equipment. The second unit is the conceptual design with CT as described in 3.3.2. The analysis of this design will be given most attention, since the operations will be carried out differently than the other candidates. This design will be denoted as DWP-CT (Coiled Tubing) and is illustrated in Figure 11. The last candidate is described in 3.3.6, where operations will be conducted similarly to DWP-BC. It will involve a different duration and rental rate due to improved tripping speeds and extra equipment on-board. The design will be denoted as DWP-SB (Setback) and is illustrated in Figure 14.

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4. Equipment – Capacities and Limitations.
4.1. Coiled Tubing

Coiled tubing has been used for intervention and workovers for decades. It is a cost-efficient solution for numerous well operations, with the advantage of continuously circulation during tripping operations. The tool is a continuous length of tubular spooled onto a reel and offers services within stimulations, perforations, sand clean-outs etc. To be able to use CT for certain sequences of a P&A operation, it is necessary to ensure it can operate and withstand under the operating conditions. This study will perform several analyses to make sure that the equipment can be utilized in the specific operations. It has been necessary to make an example well to be able to perform the calculations. The fictive well is a J-well of 3000 mMD, with a maximum inclination of 70 degrees. 2 7/8'' and 2 3/8'' CT have been included to the analysis. The tubing is grade 100 with nominal wall thickness of 0.175 in, and the CT reel includes 5000 m of string. Details is shown in Table 2 and Figure 15. The CT specifications is gathered from Varco – Coiled Tubing Handbook [18]. Tornado tool specifications is provided by Baker Hughes [19].

J-Well profile		
DLS	3/30	deg/m
α	70	degrees
L1	1000	m
L2	700	m
L3	1300	m
CT reel length	5000	m
WOB	0	kN

Table 2 - Example well specifications

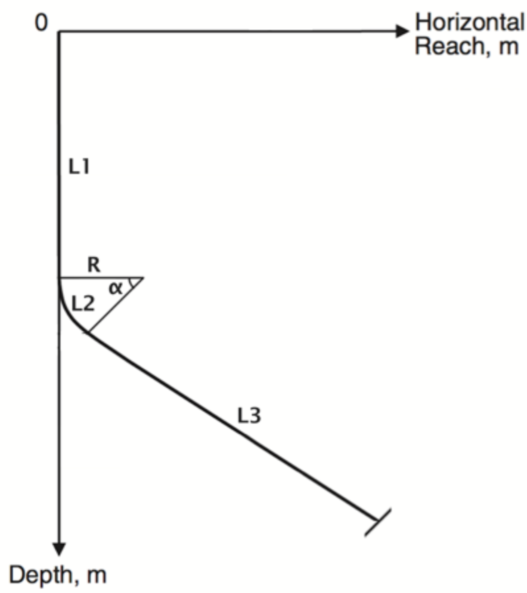


Figure 15 - Explanatory figure for well example path

4.1.1. Pumping activities

Coiled tubing can be designed to withstand high working pressures. A normal work string has limits of 10 000 psi, but specially designed coils can withstand up till 20 000 psi. Ballooning of the string is an effect resulting from large differential pressure between the annuli and inside the work string. This results in increased OD of the string simultaneously as the string is shortened, and is critical for CT. The effect is not experienced as a force unless the string gets stuck below the injector resulting in additional string tension. The sealing element used in CT is called stripper rubbers, and are designed to the specific OD of the tubing. A scenario resulting from ballooning is that the coil cannot be retrieved through the packer in the injector. Ballooning of the string can be predicted from coil specifications and will depend on fatigue and degradation of the string. Operators limit the maximum operating pressure to avoid ballooning effects. Even though the string can withstand pressures of 10 and 20 000 psi, the operations are often limited to working pressures of 5 000 psi. Thus, the following calculations will use this value as max pump pressure.

Figure 16 - A typical offshore coiled tubing stack [20]

4.1.1.1. Pressure friction loss

With a pump pressure of 5 000 psi the CT are able to return a flow rate of respectively 8.4 and 4.7 bpm in the fictive well. The calculations are based on Darcy-Weisbach equation for pressure drop and friction factor. This is one of the most general friction head loss equations for a pipe segment. The two first equations calculate the friction factor in annulus and for the straight section of the well. This is applied to calculations inside the CT beneath the injector and up annulus towards surface. To calculate the friction factor for the reeled-up CT, Sas-Jaworsky and Reed (1997) have provided a correlation to determine the friction factor. Bernoulli pressure drop equation in nozzles is collected from the book - Applied Drilling Engineering [21].

Darcy-Weisbach friction factor [22]:

$$Laminar\ flow: f_{lam} = \frac{64}{Re}$$

$$Turbulent\ flow\ in\ straight\ sections: f_{ST} = \left(\frac{1}{1{,}14 - 2 * log_{10}(\frac{\varepsilon}{D})}\right)^2$$

Sas-Jaworsky and Reed friction for reeled tubing [18]:

$$Turbulent\ flow\ in\ reeled\ sections: f_{RT} = f_{ST} + 0.0075 * \sqrt{\frac{d}{D_{reel}}}$$

Darcy-Weisbach pressure drop equation [22]:

$$\frac{\Delta p}{L} = f * \frac{\rho}{2} * \frac{v^2}{D}$$

Bernoulli pressure drop equation for nozzles (4.34) [21]:

$$\Delta \mathrm{p}_b = \frac{8.311 * 10^{-5} \rho q^2}{{C_d}^2 A^2}$$

The results of the calculations with regards to the two compared strings are shown in Table 3. With a pump pressure of 5 000 psi, respectively annulus flow velocity of 2.3 and 1.3 ft/sec is achieved. These values are applied in the calculations of cuttings transport.

CT Hydraulics

Variables:	**Symbol**	**2 7/8''**	**2 3/8''**	**Unit**
Reel diameter	**D_reel**	84	84	in
Avg. Surface roughness:	**ε**	0,0018	0,0018	in
Fluid density:	**ρ**	119	119	lb/ft3
Apparent viscosity:	**μ**	24,3	49,1	cP
Flowrate - min:	**Q**	8,4	4,7	bpm
Inside CT				
Flow area:	**A**	5,0	3,2	in2
Flow velocity:	**V**	22,5	19,7	ft/s
Reynolds number:	**Re CT**	18 071	6 295	Re
Straight friction factor:	**f s**	0,018	0,019	-
Reeled friction factor:	**f r**	0,019	0,020	-
Pressure drop CT - Straight:	**ΔP_s**	199	201	psi
Pressure drop CT - Reeled:	**ΔP_r**	142	142	psi
Pressure drop inside CT:	**ΔP CT**	4 950	4 976	psi
Annulus				
Flow area:	**A**	48,3	50,4	in2
Flow velocity:	**V**	2,3	1,3	ft/s
Reynolds number:	**Re ann**	4 064	1 188	Re
Laminar friction factor:	**f lam**		0,054	-
Turbulent friction factor:	**f turb**	0,015		-
Pressure drop annulus:	**ΔP ann**	12	11	psi
Nozzles				
Nozzle design		6 x 1/2	6 x 1/2	in
Flow area nozzles	**A**	1,18	1,18	in2
Velocity nozzles:	**V**	96	54	ft/s
Pressure drop nozzles:	**ΔP nozz**	12	38	psi
Total pressure drop:	**ΔP total**	**5 000**	**5 000**	psi

Table 3 – Maximum hydraulic capacity for 2 7/8'' and 2 3/8'' CT

4.1.1.2. Cuttings Transport

Coiled tubing will be used to conduct clean-up runs of the 9 5/8'' section after the tubing has been retrieved. The aim of the operation is to clean and circulate out settled particles in A-annulus to surface. Regularly, drill-pipe is used to clean up before cementing operations can be performed. However, for this candidate, it will only be used for clean-up operations of larger sections than 9 5/8'' casing. Drill pipe are able to pump large volumes of fluid at a high rate due to a large hydraulic diameter (ID pipe). This results in a low hydraulic area in the annulus, and high annulus flow velocities can be achieved. The operation is conducted by rotating the pipe simultaneously as fluids is circulated with the pipe located static in the bottom of the section.

Coiled tubing on the other hand, cannot achieve the same flowrates and annulus flow velocities due to its restricted ID and small OD. Subsequently, it is subjected to a large pressure loss in both the reeled-up and straight section. To be able to transport particles out of the well with CT, it is important to avoid sedimentation of particles by maintaining the particles in suspension. This can be achieved either regularly by a high annulus flow rate, or by pushing the particles out of the well. Since CT cannot be rotated and are not able to achieve the same flow velocity as DP, it must be utilized differently.

A big advantage with CT is that it is continuous, which solves the problem of settling particles during connections for regular DP. Clean-up runs with CT, often called wiper trips, are performed by tripping and pumping simultaneously. A specialised downhole cleanout-tool, a "Tornado tool", offers the option of using downhole facing jetting nozzles in order to ensure sufficient solids transport. The tool penetrates and loosens hard settled particles when the string is tripped in the well. By re-direct the jetting nozzles and trip out of the well, sufficient solids-transport can be achieved. M. Sach and J. Li reviewed over 100 solids-cleanout processes conducted on the NCS in 2007 [23]. The study summarises CT application measures for successful solids transport using a clean-out fluid with low solids-suspension properties, as used with the "Tornado tool". When the system is combined with advanced computer modelling for optimal solids transport, appropriate clean-up runs of the smaller sections, up to 9 5/8'', can be accomplished [24].

An important parameter in particle transport is the particle settling velocity. This is modelled with Stoke's law for terminal velocity of spheres sinking in a fluid. This formula assumes a relatively low fluid velocity resulting in laminar flow. As shown in

Table 3, annulus flow is turbulent for 2 7/8'' and laminar for 2 3/8'' CT. Since the latter case has the lowest fluid capacity, particle transport will be more challenging than with 2 3/8'' CT. Consequently, this will be used as example of the calculations:

Stoke's Law for terminal velocity [21] (4.102a):

$$V_s = \frac{g {d_p}^2 (\rho_p - \rho_f)}{18\mu}$$

Transport velocity of particles are defined by :

$$V_t = V_f - V_s$$

A-annulus is filled mostly with settled barite. By using a particle diameter of 75 microns, density of 4.2 SG. and transport fluid density of 1.0 SG., free particle settling velocity is calculated to be negligible compared to the fluid velocity itself. Since:

$$V_f \gg V_s \approx 0 \quad \rightarrow \quad V_t \approx V_f$$

With a pressure loss of 5 000 psi in 2 3/8'' CT, flowrates of 4.7 bpm can be achieved, leading to annulus flow velocity of 1,3 ft/sec. This value combined with the use of a tornado tool should provide sufficient cleaning of the well. By utilization of the tornado tool, the particles is pushed out of the well when the tool is retrieved to surface at speeds up till 10 m/min in a 9 5/8'' casing [19]. Preferably, 2 7/8'' CT should be used for clean-up/wiper operations even though 2 3/8'' CT is capable to perform the operations. The "Tornado-tool" is designed to use a low-density fluid, typical water, to achieve maximum annulus velocities rather than using a dense and viscous fluid to transport cuttings out of the well. The value for the pressure loss in the nozzles are a result of reduced area through the six large sized nozzles which is changing the direction of the flow. The total area of the nozzles is approximately one third of the inner area of a 2 3/8'' CT and will not result in a significant high hydraulic jet impact.

4.1.1.3. Cementing

Placement of cement plugs during P&A operations if usually conducted with DP. A paper by Schlumberger from 2017 reviews CT cementing for successful permanent well abandonment of offshore wells [25]. There are several challenges related to CT placement of cement slurry. It is important to design the cement slurry such that it is possible to pump it through your coil, without the slurry setting in the coil. A potential cause of failure in plug cementing is fluid swapping, where a heavy fluid, e.g. cement, switches place with a lighter fluid below. This would result in an inconsistent cement plug. Thus, it is important that CT cementing of permanent abandonment plugs are set on top of a competent base, such as a bridge plug or retainer.

CT cementing of permanent plugs can be performed with a pump-and-pull technique. It is done by circulating the slurry around the end of the CT while the string is pulled out at a constant rate. As the string is pulled out of hole (POOH), cement is continuously pumped simultaneously. The relation between these two parameters must be carefully controlled to make sure the extreme end of the CT string stays within the top of the slurry while cement is pumped. The technique is applied to minimize the risk of getting stuck in the slurry after it is set. This study includes CT cementing of the reservoir and overburden barrier on top of previous set EZSV's.

4.1.2. Axial Loading and Buckling

Axial loading and buckling are scenarios one is subjected to when CT is introduced to a P&A operation. Since CT are more fragile than standard DP and are more prone to helical buckling, a reasonable question is if the string will be able to reach desired depth. When compressive axial forces larger than the helical buckling load are applied to CT in a well, it buckles into a helical shape. To calculate buckling limits for the CT, there have been used three different mathematical models for the three different sections of the well; vertical-, curved- and inclined section. Both sinusoidal and helical buckling is considered [26] (next page):

Vertical section:

$$\text{Wu et. Al (1992): } F_{sin} = 2.55(EIw^2)^{1/3}$$
$$\text{Wu et. Al (1993): } F_{hel} = 5.55(EIw^2)^{1/3}$$

Curved section:

$$Mitchell\ (1999)\text{: } F_{sin} = \frac{2EIk}{r} * \left[1 + \sqrt{1 + \frac{wsin\alpha r}{EIk^2}}\right]$$
$$Mitchell\ (1999)\text{: } F_{hel} = 2\sqrt{2}F_{sin}$$

Inclined section:

$$\text{Dawsons and Paslay (1984): } F_{sin} = 2\left(\frac{EIw * sin\alpha}{r}\right)^{1/2}$$
$$\text{Miska et. al (1996): } F_{hel} = 2\sqrt{2}F_{Dawson\ Paslay\ sinusoidal}$$

These equations give a limitation for the tolerable compressive forces within the string. To define the other end of the working window we need to calculate the maximum tensile strength of the string. The equations are based on yield strength of the material (Grade 100) and the cross-sectional area.

Cross-sectional area:

$$A = \frac{\pi}{4}\left({A_o}^2 - {A_i}^2\right)$$

Tensile yield strength:

$$F = \sigma_y A$$

To be able to analyse if the CT stays within the working window for the well example reviewed in 4.1, there is need to perform a drag analysis for the two different scenarios; RIH and POOH. The friction coefficients used for modelling is respectively 0.30 and 0.25 for the two scenarios. The analysis is conducted by calculating drag/compression from the end of the CT-string and up the well. The analysis is based on weight on bit (WOB) to be zero and the formulas for drag calculations are divided into two; straight and curved sections:

Straight sections:

$$F_2 = F_1 + \beta w \Delta L \{cos\alpha \pm \mu sin\alpha\}$$

Curved section:

$$F_2 = F_1 * e^{\pm\mu|\theta_2-\theta_1|} + \beta w \Delta L \left\{\frac{sin\alpha_2 - sin\alpha_1}{\alpha_2 - \alpha_1}\right\}$$

Where + refers to POOH and – to run in hole (RIH). Appendix B shows the results of the drag calculations for 2 3/8'' and 2 7/8'' CT in the example well. Both the strings are within buckling and tensile limits when run in the respective wellbore.

4.1.3. Tripping

Tripping of CT is one of its greatest advantages compared to regular drill pipe. Since there are no connections that needs to be performed, tripping with CT can be done without stops enabling a higher tripping speed. This speed is determined by the speed characteristics of the injector. A normal CT stack should be able to RIH at speeds up to 100 ft/min, and POOH up to 240 ft/min, depending on well design and type of BHA [27]. The speed varies with the criticality of the location of the CT end and the operator's knowledge of the well. A value between the two numbers will be used for the calculations during the analysis of the study. A full review of tripping speeds will be presented in Table 6.

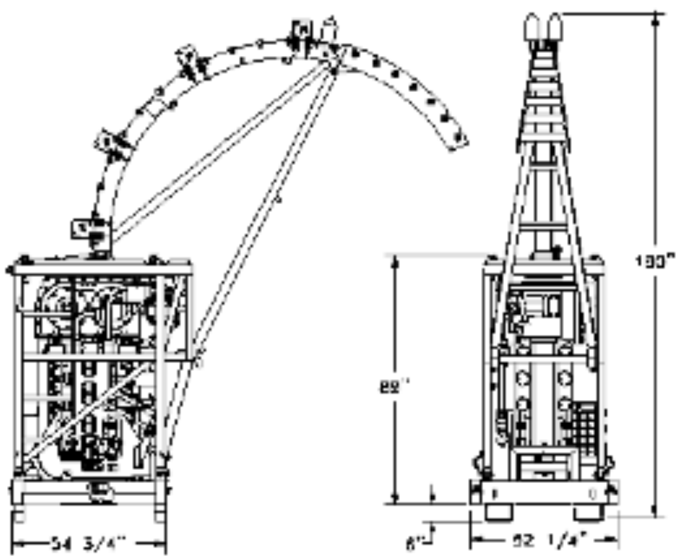
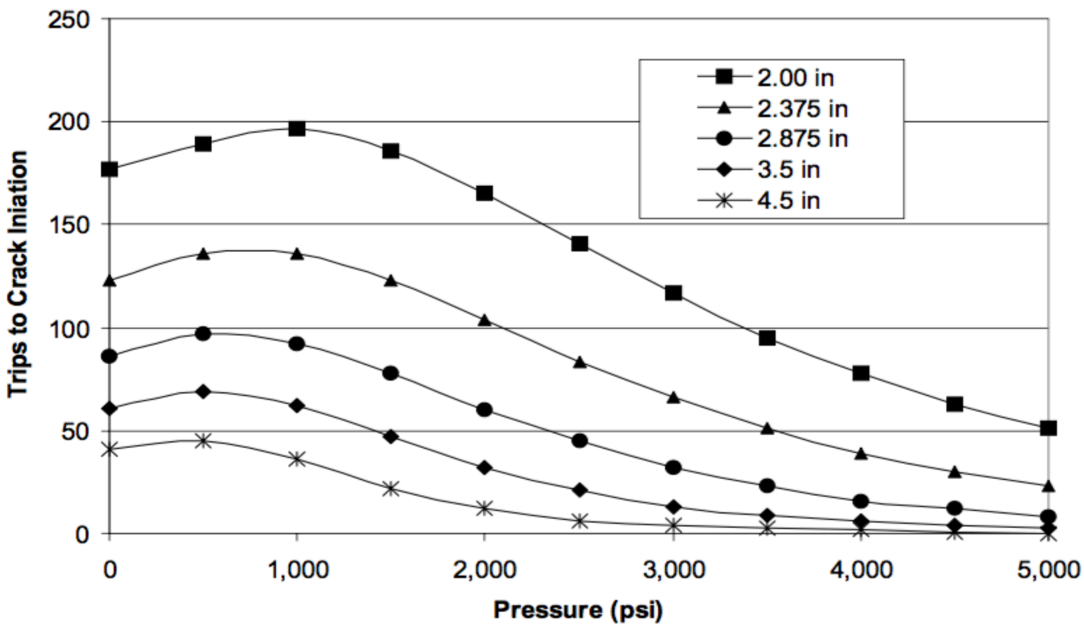


Figure 17 - CT injector and guide arch schematic [18]

4.1.4. Fatigue

Another issue to evaluate is fatigue considerations of the CT. The string is plastically deformed when it is run in and out of the well over two sections: On/off the reel and over the guide arch, where it is first bent and then straightened. After a certain number of runs it must be replaced. The durability of the string depends on numerous variables such as size of string, material, wall thickness, bend radius and operating pressure. Pumping with a high pressure while CT is run in or out of the wellbore will reduce the lifetime of the string dramatically. Pumping of fluids with high pump pressure should thus be conducted with the coil static in the well. Figure 18 shows the relationship between lifetime (number of trips) vs string size and working pressure [18]. Calculating the fatigue life of a CT is very complex, and must be done by computer modelling. This study will not elaborate further of CT fatigue, but emphasise the importance to consider the variables when CT is utilized in the operation.



CT Diameter	Varies
Wall Thickness	0.175 in
Reel Diameter	84 in
Guide Arch Radius	120 in
Material Grade (yield Stress)	80 kpsi
Failure Criterion	Crack Initiation

Figure 18 - CT fatigue based on working pressure and number of trips [18]

4.2. Tripping Speeds for Wireline and Drill Pipe

Wireline and drill pipe is commonly used in P&A operations, and thus will not be elaborated as thorough as CT. The most important parameter of the equipment for the analysis is tripping speeds. Potential SOW and limitations are not included, since the methodology and usage is well known within the industry. The next two sections will review tripping speeds with WL and DP.

4.2.1. Wireline

Running speed of wireline depends on well geometry, BHA, type of operation and the operator's knowledge of the well. Different types of WL can be run at different speeds. A typical E-line, used in P&A operations, can run up to 230 ft/min for non-live well operations and are limited to 150 ft/min for live well operations. Some parts of the well needs to be run with reduced speed, i.e. above DHSV. For slickline operations, the WL can be run at a higher speed, up to 500 ft/min. [28]

4.2.2. Drill Pipe

DP tripping has been conducted and perfected over the last decades. From a manual operation, the industry has tried to streamline the operation to reduce crew working hands-on with the pipe handling equipment. A lot of the sub-sequences of DP tripping have been automated, resulting in better HSE and faster tripping. Today, DP tripping varies quite much due to the variations of the derricks and crew on board. A modern rig will most likely be able to trip faster than an old manual rig. The most modern rigs on the market today can trip 3000 ft/hr, 50 ft/min. With a derrick stand consisting of three range 2 DP of 30 ft, the rigs are able to trip almost one stand every other minute.

DWP-BC are not able to trip premade stands of range 2 DP, but runs single joints of range 3 DP. Compared to a modern drilling rig, the unit trips substantial slower with 1000 ft/hr.

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5. Methodology
5.1. Well Operation Sequences

This study has been able to collect two “Final Well Reports” from two previous well abandonments of platform wells. The wells are located within the same NCS offshore platform and have been operated by one of the major operators working on the shelf. The acquired “Final Well Reports” are based on two real P&A operations conducted on the NCS and include detailed description of the operations, with amongst others a “Time Planner” with accumulated time per operational sequence. The reports have been distributed to the study via the University, and thus wells, field and operator will be anonymized. Table 4 and Table 5 shows the compiled data from the two “Final Well Reports”. Detailed operational sequences of the tables can be found in Appendix C and Appendix D.

Operational sequence	Duration [hrs]	Accumulated time [days]
Rig work	56,1	2,3
Pull tubing and clean well	87,5	6,0
Establish reservoir barrier	53,7	8,2
Set base for PWC barriers	15,0	8,8
Establish first PWC barrier	101,0	13,1
Establish second PWC barrier	98,0	17,1
Retrieve C-section	47,0	19,1
Cut and pull 9 5/8" casing	58,0	21,5
Retrieve B-section	73,0	24,6
Cut and pull 13 3/8" casing	52,0	26,7
Establish open hole to surface barrier	55,0	29,0
Finalizing operations	39,0	30,6

Table 4 - Operational sequence - Well 1

Operational sequence	Duration [hrs]	Accumulated time [days]
Rig work	50,0	2,1
Pull tubing and clean well	93,3	6,0
Establish reservoir barrier	50,0	8,1
Retrieve C-section	33,0	9,4
Cut and pull 9 5/8" casing	81,0	12,8
Establish 13 3/8" barrier	105,0	17,2
Retrieve B-section	81,0	20,6
Cut and pull 13 3/8" casing	58,0	23,0
Establish open hole to surface barrier	55,0	25,3
Finalizing operations	39,0	26,9

Table 5 - Operational sequence - Well 2

Since the two wells are located within the same platform and are subjected to the same formations, they have been finished quite similar. Due to differences in status of the external well barriers in the two wells, they have been P&A'ed with two different methods. The first well retrieved tubing and establish permanent barriers against the reservoir initially. Furthermore, the operation established the remaining barriers, including isolation of an overburden reservoir, most likely containing hydrocarbons. It is symptoms of insufficient cement in B-annulus between 9 5/8'' and 13 3/8'' above the formation. PWC technology was used to establish a cross-sectional barrier. The operation set 2x50m plugs with HydraHemera to give sufficient zonal isolation for permanent P&A in the overburden. Furthermore, 9 5/8'' and 13 3/8'' casing was cut to be able to establish a cross-sectional open hole to surface barrier.

The second well include many similarities with the first well, but the B-annulus cement above the overburden hydrocarbon reservoir was verified as a sufficient barrier. This lead to an easier operation where cement plugs was set inside 13 3/8'' casing on top of a mechanical plug. The remaining operation were conducted similarly to the first well.

5.2. Operational Comparison – "CJ70" vs. "DWP"

This study is comparing the three designs of the extended reach, workover cantilever up against a regular J/U rig, reviewed in 3.4. The comparison is based on the equipment on-board the two units, where there have been necessary to select a rig design to compare DWP up against. DWP will be compared with a design widely used within the industry, the Gusto MSC CJ70 [29]. This is a modern three-legged cantilever type jack-up drilling rig with design specs within the same range as for DWP. The unit will be denoted as CJ70 in this study, and will be linked to the operations data gathered from the two "Final Well Reports".

5.2.1. Application of Equipment, DWP-SB and DWP-BC

The two candidates DWP-SB and DWP-BC will be simulated to perform the P&A operations on the two well examples with the same equipment and methodology as CJ70. There will not be added or subtracted any sequences to the operation of the two candidates, but the duration of the operations varies with tripping speeds and casing retrieval efficiency.

5.2.2. Application of Equipment, DWP-CT

To be able include DWP-CT in the comparison with the other candidates, it is necessary to define what type of equipment will be used during the different operational sequences. The purpose of this concept design is to use most efficient equipment for each sub-operation. The selection of what equipment that will be used for the different operations will depend on several factors. First, it is necessary to ensure that the equipment is capable to physically conduct the respective sequence in a safe manner, providing a satisfactory result. Furthermore, there must be done an evaluation to figure out what equipment that will be most efficient to conduct the operation. These durations must include the time to rig up and down equipment and the actual time spent on the specific operation. In the next sections, the different equipment will be linked to the specific operational sequences they will perform.

5.2.2.1. WL

Wireline is the lightest equipment with the highest tripping speed, and should preferably be used to conduct sequences that doesn’t require pumping of fluids. Logging, perforating, cutting sections up to 9 5/8’’ and setting/pulling shallow plugs to nipple down (N/D) wellhead section are the sequences where WL will be utilized. Wireline will perform these tasks in the sequences where it is the most time-efficient of the three alternatives, based on the total duration to rig and run the equipment.

5.2.2.2. CT

Coiled tubing is tougher than WL, thus having a wider work scope. Its ability to pump fluids enables it to be utilized where pumping is required, within the tools limits. Similarly to WL, it should be done an evaluation if it is beneficial to mobilize CT for certain operations with regards to the extra time used to rig the equipment for the operation, and added time due to pumping activities. The tool can perform the same sequences as wireline in addition to the pumping operations. The most challenging pumping operation where CT will be deployed is during clean-ups/wiper trips of the 9 5/8'' section. This operation has been elaborated in 4.1.1. Based on this information and the fact that 2 3/8'' and 2 7/8'' CT have been used to conduct such operations on the NCS previously, CT will be used to wash the 9 5/8'' section of the well [19]. Furthermore, CT will be utilized to perform operational sequences, such as;

- Plug cementing on top of mechanical plugs
- Set/pull shallow plugs to N/D wellhead sections
- Logging of casings

5.2.2.3. DP

Drill pipe is the most robust and durable equipment, and can practically conduct all sequences during a P&A operation. There may be disagreements of what is the best purposed tool for each operational sequence. Since DWP-CT runs single R3 pipes, there are great incentives to use CT and WL. For all operations where these tools can be used and will decrease duration, they are the best purposed tool for the operation, due to reduced tripping time. For DWP-CT, drill pipe will however be used for the heavy operations such as;

- Cut of large sections
- Pick up to pull tubing/casing
- Clean-ups of large sections
- Wash and Cement in PWC work

5.2.3. Duration Differences

The most important parameter of cost reduction in a P&A operation is the duration of the operation. The next section will demonstrate the duration differences between the units. Some of the operations will add duration, other will reduce the duration. The section is written in DWP point of view, compared to the CJ70.

Tripping

The major time saver for the unit is the situation where CT or WL can be run instead of DP. CT and WL is respectively 3,4 and 4,6 times more efficient during tripping vs. tripping of DP with a CJ70. Since tripping of DP with the DWP-CT is three times slower than tripping with DP with a regular J/U, it should be evaluated if it is possible to use other alternatives to conduct the operation. If we compare CT and WL with tripping of DP with the DWP-CT, the equipment is respectively 10,2 and 13,8 times more efficient. This leads to tough decision when evaluating what equipment should be used for the different operations. In the analysis, the duration differences will be calculated based on the tripping distance gathered from the “Final Well Report”. This will either add or subtract time to the total duration, depending what equipment is replacing the original operation. To conclude; Utilization of CT/WL will decrease duration, whilst DP tripping with DWP derrick will increase the duration. Table 6 reviews the tripping speeds for CJ70 and the three conceptual designs of DWP.

Unit	**CJ70**	**DWP-CT**	**DWP-SB**	**DWP-BC**	
Equipment	DP	CT	DP	DP	WL
Speed ft/hr	3 000	7 200	1 350	1 000	13 800
Speed m/hr	914	2 195	411	305	4 206

Table 6 - Tripping speed comparison

Mobilization/Demob of Equipment

To be able to evaluate what kind of equipment that should be used for the different operations, we need to elaborate about the extra time related to organize equipment to perform the operations. The unit is designed in a way to minimize duration related to organizing of the equipment. The intention is to utilize it more frequently in the operations. Mob/demob of CT is conducted by changing from a low-pressure to a high-pressure riser, and skid the CT injector above well centre before the equipment is tested. This operation is assumed to be 3 hrs. Mob/demob of WL is a well-known standard operation and takes 2 hrs, similarly to CJ70.

Retrieval of Tubing/Casing

It is not necessarily obvious that there should be any duration differences between the two units when it comes to retrieval of tubular from the well. The rack and pinion derrick is built to handle single tubular, and will due to pipe handling equipment work more efficient than a regular derrick. It is assumed to be able to retrieve casing and tubing 15% faster compared to a regular J/U-rig.

Cleanouts/Pumping Through CT

Due to a smaller ID of CT compared to regular 5 1/2'' DP, pumping operations such as clean-ups, well displacement and cementing will gain time to the operation. After a typical cementing operation, the well is displaced to seawater and treated injection water to avoid further contamination of well fluids. The duration of this operation will depend on the fluid capacity of the tool-string used. By calculating volumetric with the original duration, it is possible to predict the number of annuli pumped during the operation. The calculation is based on annulus volume differences, ΔV, and flow rate capacity differences, ΔQ. Volumetric calculations like this is applied to calculate duration differences between CT and DP for well displacement.

6. Analysis and Results

This section lay a foundation to do a cost comparison for the different candidates based on the duration data, which is also included to the section.

6.1. Value Proposition

6.1.1. Intro

An issue by implementing the unit in today's market is that it will compete with older rigs that have been able to pay down the investment, decreasing the expenses related to repayments. In a crowded rig market as we experience these days, rig owners are offering rigs close to operational expenditures, to avoid cold stacking their units. A new-build, as DWP, will in today's market meet great competition for contracts. The analysis will be conducted in an "operator point of view", and all the necessary expenses related to a P&A operation will with the best efforts be added. The result of the value proposition will give potential savings/extra expenses related to employment of DWP vs a regular J/U rig. The comparison will include four candidates; DWP-BC, DWP-CT, DWP-SB and CJ70. All comparison data represents the operation of CJ70 and is based on the "Final Well Reports" gathered for this study.

To be able to conduct a reliable analysis of the potential upside of utilization of the designs, there is need for a thorough overview of the costs. After discussions with various parts in the industry, there seems to be a consensus about the rule of thumb that total costs for well abandonment can be anticipated to be twice the daily rental rates of rigs. This rule of thumb is not accurate and can be viewed as a conservative estimate. Such assumption adds uncertainty to the analysis. The problem is that the systems that are compared utilize different equipment during the operations and are related to a different cost. This leads to the need to take a closer look at these numbers. The different expressions used in the following must be thorough explained, to avoid confusion.

6.1.2. Equipment

To be able to cut operating cost for DWP the amount of equipment on board have been reduced. The unit is equipped with "of the shelf" equipment, but since it is designed to do lighter work than a regular drilling unit, it has been possible to reduce the number of each component. Examples of equipment that have been cut down is; shakers, mud pumps, mixing- and transfer pumps. In addition to less equipment on board, the unit is fitted with a smaller derrick, only able to pull a fourth of a modern J/U rig. This leads to a decrease in demand of power on-board. With less active generator sets working, the fuel consumption will decrease. By reducing the quantity and magnitude of the equipment on board, there will be less need for maintenance and service of the equipment. All these actions are made to be able to offer a low-cost alternative to plug wells.

6.1.3. Personnel Requirements

DWP is designed to be able to conduct P&A operations with less personnel on board. By reducing the amount equipment on board, there is less demand for technical personnel to do maintenance and operate equipment. The technical positions which has been reduced is; electricians, mechanics, hydraulics, roustabouts and roughnecks. By reducing the number of technical personnel working on board, it will also be less need of catering services to accommodate the crew. The company have made it possible cut a standard double shift crew from a POB of 80 to 50. This is reflected through the daily rental rates of the rig. Any extra equipment or personnel that is needed beyond what is regarded as the standard for the unit will be covered by the overhead expenses. These extra crew are typically working with cement, mud engineering, casing, wireline or CT.

The company also have ambitions to cross-train their drill crew to assist with the use of service equipment such as WL and CT, thereby reducing the need of a full additional crew for service operations. Cross-training of personnel could be applied to a regular J/U unit as well, but since it is designed to drill wells and executes all sorts of operations, it will most likely not be realised for such unit. The advantage with modern J/U units is their ability to fast tripping with DP, and thus is the threshold to include CT to the operations very high. The extra time and rental rate to mobilize such equipment should be justified by a reduction of total cost and duration in well operations.

6.1.4. Rig Rental Rate

The expression "rig rental rate" is used to express the expenses related to rental or charter the rig itself. The rate includes the cost of standard personnel and equipment to operate the unit, daily maintenance of the equipment, spare parts, catering and repayment of any debt related to the purchase of the unit itself.

The selection of daily rental rates to compare DWP with is not an easy task. There are many variables that would influence the decision. An obvious issue is to select what kind of market the unit should be compared against. The past years have shown that the rig market can be very volatile. It is a wide interval to choose within, from long-term market rates above 500k USD/day to spot-market rates below 200k USD/day. To choose a rate in either end of the range would not be fair for either parts. Based on all jack-up rigs that is on a contract on the shelf per May 2017, the average rate is 360k USD/day [2]. This number is not necessarily a representative number for a new rate in today's market, since a lot of the contracts were signed several years ago. The rig to be compared with DWP is a CJ70, a modern J/U rig, in the upper quality range of J/U rigs on the shelf. After discussions with various parts from both the industry and university a base rental rate of 330k USD/day has been selected as representative for a CJ70 J/U rig in a normal market.

When it comes to the selection of a base rental rate for DWP, the decision is not that difficult. The company have ambitions to deliver the unit with a base rate below 200k USD/day, and this number will be used for the analysis. These rates are only the base rates for the units.

6.1.5. Overhead Expenses

Overhead expenses are all the additional expenses to the base daily rental rates for the rigs. Examples of overhead expenses are 3rd party vendor services and equipment rental, transportation like helicopter and standby vessels, logistics, onshore management and consumables like diesel. The largest difference between on board 3rd party vendor equipment for the units is the CT spread of 25k USD/day for the duration where the equipment is active. This spread includes direct impairments of the equipment and crew wages. The crew consist of two shifts of 4 operators plus 1 supervisor. By including CT as base equipment on DWP-CT, increased logistics with regards to POB and equipment maintenance are present. For the days where the CT spread is inactive, the spread to maintain the equipment on board is 10k USD/day [19]. This must be differentiated and included to the overhead expenses. The difference between an active and inactive CT spread roots from the extra wages and cost of accommodation for the crew. To include the cost to mobilize/demobilize the crew to the operations there are added 3 days with the cost difference between the active and inactive spread (15k USD/day). The extra cost related to include the setback on the rig is 5k USD/day [15]. All the units require WL and casing equipment to perform a P&A operation, and thus, will be included in the following general overhead expense described.

It is important to add the overhead expenses to the calculation to get a realistic relationship between the cost of the units. If the inclusion of these cost were avoided it would favour CJ70 since it has the highest overhead expenses of the two units. The overhead expenses could have been discretized down every detail, but this is not the focus of the study and therefore will not be included. Instead it will apply the earlier described rule of thumb to double the general rig rental rate to get the total daily costs for the two units. This assumption can be looked upon as incorrect and will add an uncertainty to the analysis. Since part of the overhead reflects the size and POB of a rig, the assumption will be applied. It favours the DWP, but to compensate for this favour the equipment spread will be added on top of the base rental rate before the rule of thumb is implemented. Thus, the two total daily rates will be:

	1000 USD/day		
Unit	**Base Rate**	**Extra cost**	**Total rate**
CJ70	330	0	660
DWP-CT active	200	25	450
DWP-CT inactive	200	10	420
DWP-SB	200	5	410
DWP-BC	200	0	400

Table 7 - Unit Rental Rates Summary

6.1.6. Time

To be able to calculate the profitability of the units compared to a CJ70 for operations with the two well examples, it is necessary to outline the operational duration differences. The next tables are based on the original operation duration presented in Table 4 and Table 5, combined with the variables outlined in 5.2.3. The tables compare the three candidates with CJ70 for well 1 and 2. The tripping duration differences are calculated by speeds elaborated in Table 6 and tripping distances gathered from the "Final Well Report".

Operational Sequence	**CJ70 Duration [hrs]**	**DWP-CT Duration [hrs]**	**DWP-SB Duration [hrs]**	**DWP-BC Duration [hrs]**
Rig work	56,1	56,1	56,1	56,1
Pull tubing and clean well	87,5	62,4	91,6	97,6
Establish reservoir barrier	53,7	55,1	63,2	69,3
Set base for PWC barriers	15,0	12,6	21,9	26,4
Establish first PWC barrier	101,0	103,2	125,2	140,6
Establish second PWC barrier	98,0	102,3	118,0	130,7
Retrieve C-section	47,0	47,0	47,0	47,0
Cut and pull 9 5/8'' casing	58,0	54,9	55,2	56,9
Retrieve B-section	73,0	73,0	73,0	73,0
Cut and pull 13 3/8'' casing	52,0	50,6	49,0	50,6
Establish OHTS barrier	55,0	61,2	61,2	65,1
Finalizing operations	39,0	43,2	40,7	41,8
SUM	**735,3**	**721,6**	**802,2**	**855,1**

Table 8 - Duration comparison - Well 1

Operational Sequence	**DWP-CT Variation [hrs]**	**DWP-SB Variation [hrs]**	**DWP-BC Duration [hrs]**
Rig work	0,0	0,0	0,0
Pull tubing and clean well	-25,1	4,1	10,1
Establish reservoir barrier	1,4	9,5	15,6
Set base for PWC barriers	-2,4	6,9	11,4
Establish first PWC barrier	2,2	24,2	39,6
Establish second PWC barrier	4,3	20,0	32,7
Retrieve C-section	0,0	0,0	0,0
Cut and pull 9 5/8'' casing	-3,1	-2,8	-1,1
Retrieve B-section	0,0	0,0	0,0
Cut and pull 13 3/8'' casing	-1,4	-3,0	-1,4
Establish OHTS barrier	6,2	6,2	10,1
Finalizing operations	4,2	1,7	2,8
SUM	**-13,7**	**66,9**	**119,8**

Table 9 - Duration differences - Well 1

Operational Sequence	**CJ70 Duration [hrs]**	**DWP-CT Duration [hrs]**	**DWP-SB Duration [hrs]**	**DWP-BC Duration [hrs]**
Rig work	50,0	50,0	50,0	50,0
Pull tubing and clean well	93,3	84,0	99,6	106,8
Establish reservoir barrier	50,0	47,2	58,1	63,3
Retrieve C-section	33,0	35,7	33,7	34,1
Cut and pull 9 5/8'' casing	81,0	73,6	81,2	86,3
Establish 13 3/8'' barrier	105,0	108,9	119,4	128,6
Retrieve B-section	81,0	83,7	81,7	82,1
Cut and pull 13 3/8'' casing	58,0	57,7	55,7	57,7
Establish OHTS barrier	55,0	61,2	61,2	65,1
Finalizing operations	39,0	43,2	40,7	41,8
SUM	**645,3**	**645,2**	**681,3**	**715,9**

Table 10 - Duration comparison - Well 2

Operational Sequence	**DWP-CT Variation [hrs]**	**DWP-SB Variation [hrs]**	**DWP-BC Duration [hrs]**
Rig work	0,0	0,0	0,0
Pull tubing and clean well	-9,3	6,3	13,5
Establish reservoir barrier	-2,8	8,1	13,3
Retrieve C-section	2,7	0,7	1,1
Cut and pull 9 5/8'' casing	-7,4	0,2	5,3
Establish 13 3/8'' barrier	3,9	14,4	23,6
Retrieve B-section	2,7	0,7	1,1
Cut and pull 13 3/8'' casing	-0,3	-2,3	-0,3
Establish OHTS barrier	6,2	6,2	10,1
Finalizing operations	4,2	1,7	2,8
SUM	**-0,1**	**36,0**	**70,6**

Table 11 - Duration differences - Well 2

The results of the duration comparison show that for Table 9 and Table 11 there are respectively -13,7 and -0,1 hrs difference in operations of CJ70 and DWP-CT. In a scientific perspective, these are of an insignificant value within estimation error. With respect to the next two candidates, there are larger differences. Due to large variations in tripping speed between CJ70 DWP-SB and DWP-BC, the duration differences are respectively 66,9 and 36 hrs and 119,8 and 70,6 hrs.

6.2. Results

Based on the outlined daily rates in for the units in Table 7 and the duration differences for the two distinctive operations, the profitability of the unit can be plotted. The next figures and table are based on the outlined data and values.

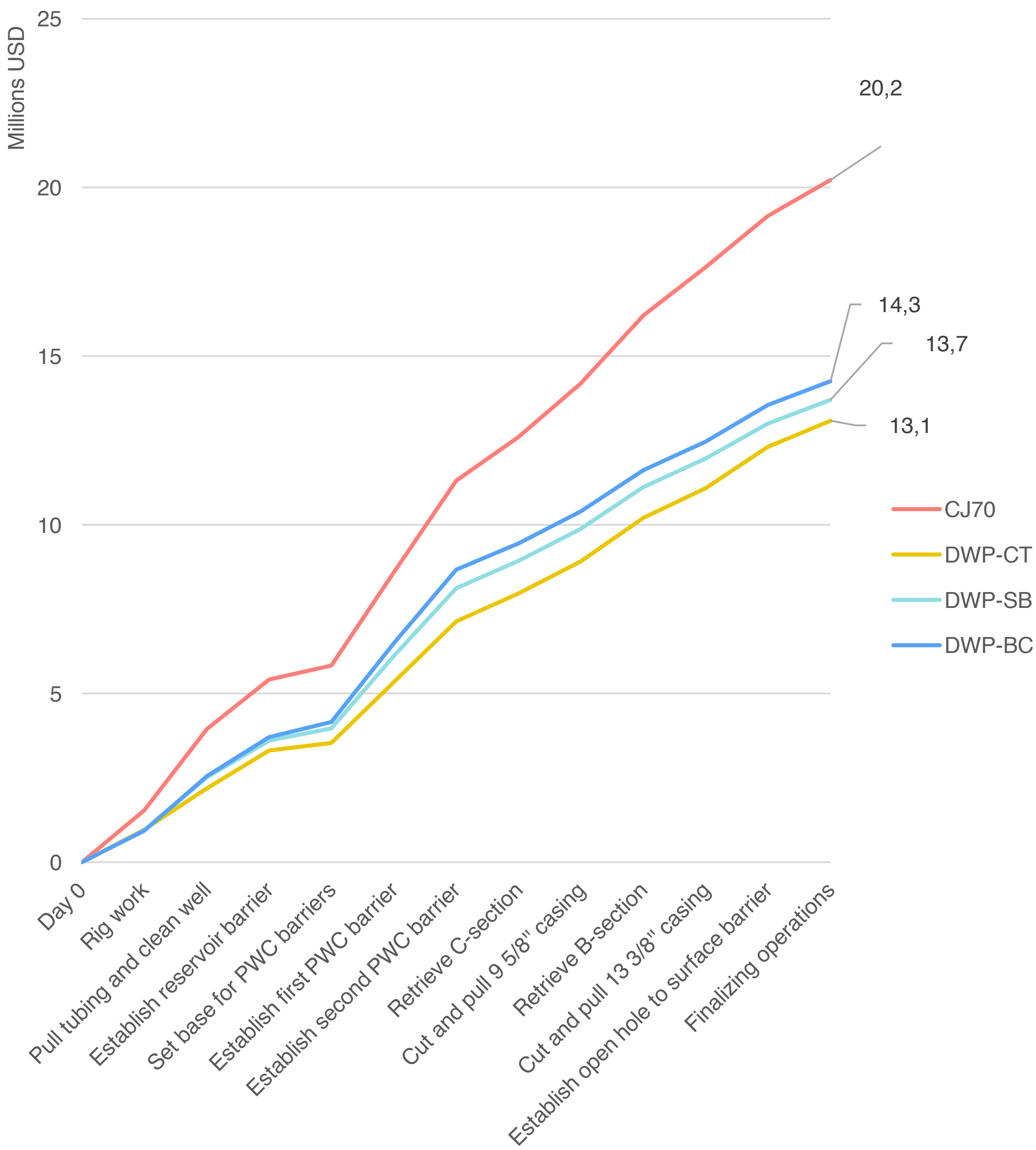

Figure 19 - Cumulative cost comparison - Well 1

	Discrete Cost Difference Thousand USD		
Operational sequence:	DWP-CT	DWP-SB	DWP-BC
Rig work	561,0	584,4	607,8
Pull tubing and clean well	1 186,6	841,4	779,7
Establish reservoir barrier	352,8	396,4	321,5
Set base for PWC barriers	192,8	37,6	-26,9
Establish first PWC barrier	971,8	638,8	434,3
Establish second PWC barrier	905,5	680,0	517,5
Retrieve C-section	470,0	489,6	509,2
Cut and pull 9 5/8" casing	633,7	651,9	647,2
Retrieve B-section	730,0	760,4	790,8
Cut and pull 13 3/8" casing	544,5	592,2	586,7
Establish OHTS barrier	289,2	467,1	426,9
Finalizing operations	300,8	376,5	375,0
Sum:	**7 139**	**6 516**	**5 970**
Profit:	**35,3 %**	**32,2 %**	**29,5 %**

Table 12 – Discrete cost comparison vs. CJ70 – Well 1

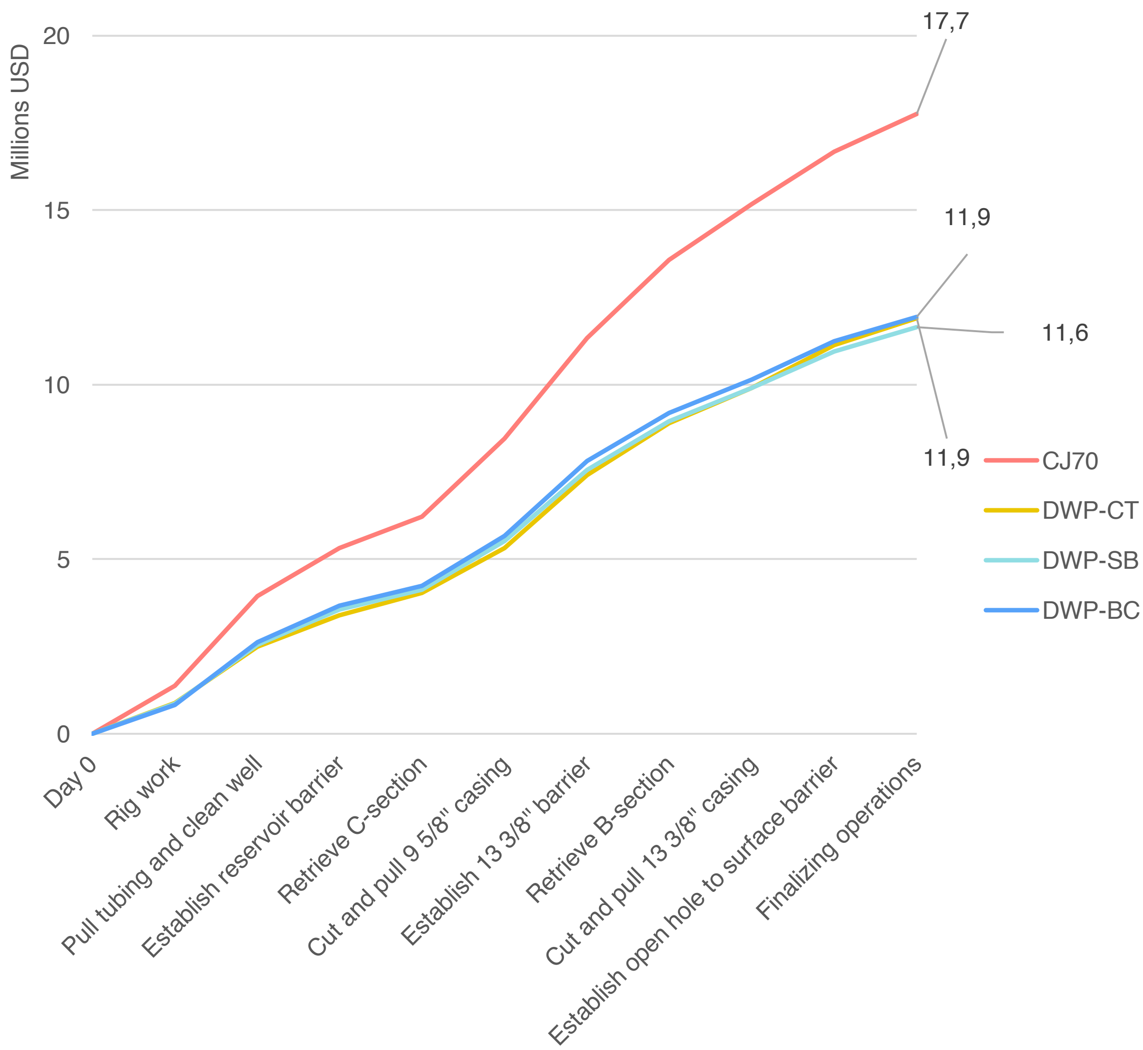

Figure 20 - Cumulative cost comparison - Well 2

	Discrete Cost Difference Thousand USD		
Operational sequence:	DWP-CT	DWP-SB	DWP-BC
Rig work	500,0	520,8	541,7
Pull tubing and clean well	941,7	865,2	786,1
Establish reservoir barrier	489,3	381,6	319,4
Retrieve C-section	264,8	332,3	339,3
Cut and pull 9 5/8" casing	938,8	840,3	789,3
Establish 13 3/8" barrier	789,9	847,6	744,6
Retrieve B-section	749,8	832,3	859,3
Cut and pull 13 3/8" casing	585,4	643,2	633,4
Establish OHTS barrier	289,7	467,1	426,9
Finalizing operations	300,8	376,5	375,0
Sum:	**5 850**	**6 107**	**5 815**
Profit:	**33,0 %**	**34,4 %**	**32,8 %**

Table 13 – Discrete cost comparison vs. CJ70 – Well 2

6.3. Market Potential – NCS

Based on NPD well data, there can be conducted a fairly good analysis of the potential wells where DWP can be used for well abandonment [30]. Out of 4499 development wellbores, there are 2249 wellbores that can be categorized as “Active” wellbores. These wellbores are either producing, injecting, being suspended, drilled etc. If we sort these wellbores by their facilities, there are 1031 wellbores located subsea and 1218 platform wellbores. Since this study focus on platform wellbores, the market potential presented will be based on these wellbores, even though there are several subsea wellbores within the units SOW. The unit is restricted to work within the following parameters:

- Maximum water depths 94 meters
- Total height to well deck - 135 meters.

If we sort the remaining platform wellbores with the unit limitations, it remains 296 platform wellbores. The next figures illustrate the NPD well data reviewed above.

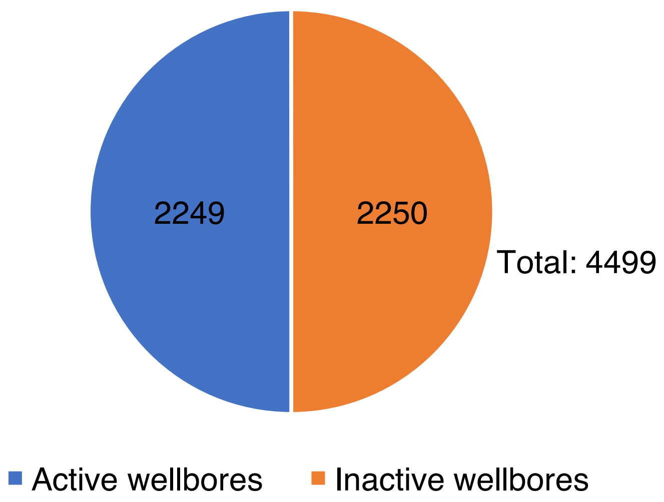

Figure 21 - Development wellbores on the NCS

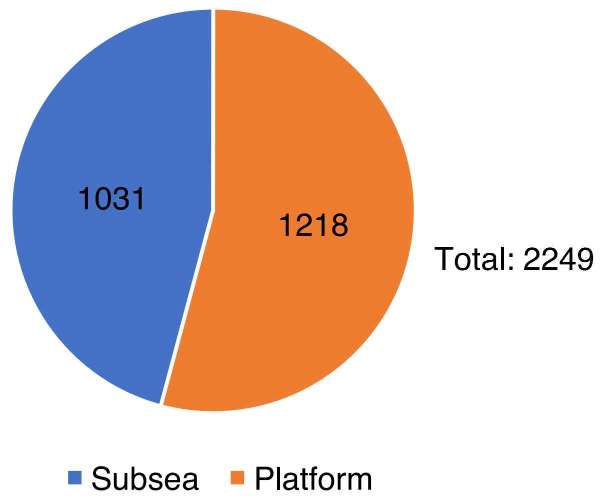

Figure 22 - Active development wellbores on the NCS

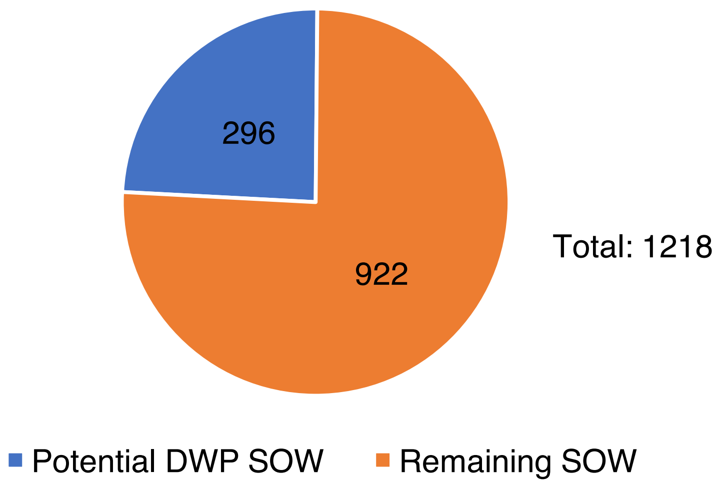

Figure 23 - Active platform development wellbores on the NCS

7. Discussion

With information of the magnitude of the potential market for the unit, the total savings by employing DWP on the NCS can be calculated. The calculations assume the 296 wells to have reasonably comparable conditions and that the two well examples gathered from the "Final Well Reports" collectively represent these wells. An average total cost of the two wells is used as multiplier to the total number of wells.

Total cost saving based on the average value of cost difference for the two wells:

$$DWP - CT = 296\, wells * \frac{(7139 + 5850) * 1000}{2} USD = 1{,}92\, bUSD$$

$$DWP - SB = 296\, wells * \frac{(6516 + 6107) * 1000}{2} USD = 1{,}87\, bUSD$$

$$DWP - \mathrm{BC} = 296\, wells * \frac{(5970 + 5815) * 1000}{2} USD = 1{,}74\, bUSD$$

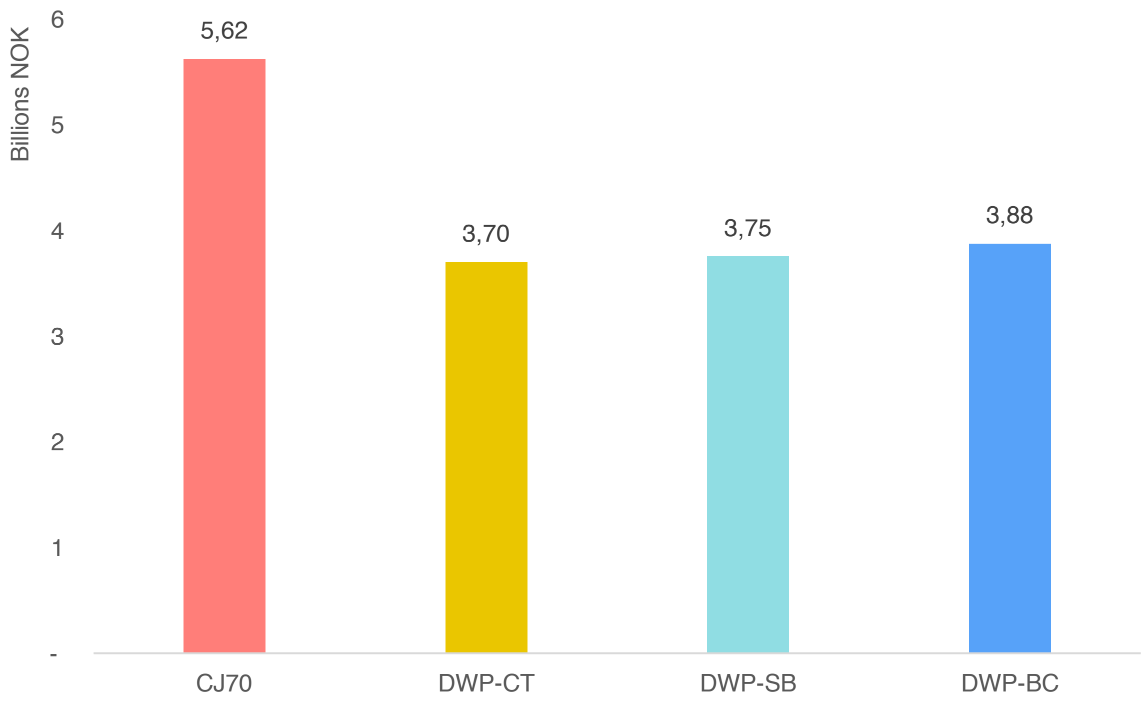

Figure 24 - Expected total cost to P&A platform wells within DWP scope on the NCS

The numbers from Figure 24 shows the total expected expenses related to P&A of the 296 wells within unit scope.

The numbers and figures presented above is based on the data provided for the study, and on the qualified assumptions made for the variables. DWP-CT conducts the operations in slightly less time than the CJ70, and due to the relatively lower total daily rates it is profitable with respectively savings of 35 and 33 percent for the two well examples. For well 1, DWP-CT provides the largest profits out of the candidates. Since the unit day rate is two thirds of CJ70, it can finish the work 1/3 slower and still be profitable. The profitability of DWP-BC is within the same range as DWP-CT, but slightly lower. The lower total daily rental rate for the unit does not equalize for the extra duration added due to slow tripping. For other well examples these scenarios might switch, depending on the amount of drill pipe tripping required to conduct the operations. What is interesting is to recognise is that DWP-SB have better profitability for well 2 than DWP-CT. The set-back design has profits of respectively 32 and 34 percent. This concludes that there is necessarily not one design that will be cheapest for all well abandonment activities we might face. To be able to select the design best suited for the NCS, a more thorough well analysis have to be conducted. Even though DWP-SB shows best profits for well 2, the profit differences between the conceptual designs for well 2 are of an insignificant value, and within estimation errors.

Learning Effects

By implementing a purpose-built unit to conduct P&A operations, the crew on board the units will over time have improvements in performance due to learning effects. Repetition of the same operation tends to reduce P&A time as learning is gained. This is possible to model by Jablonowski et al. (2011) [31]. An important factor is that the crew gets more experience from the specific field, and can thereby apply learnings to the next well. These learnings can often be field specific such as formation related, but also technical related such as equipment challenges experienced during the previous well. The learning effects experienced throughout a regular P&A campaign is proven to have substantial effects on the duration of the operations.

Figure 25 shows an example of P&A duration development during a typical campaign conducted on the NCS. This is only one out of several similar examples.

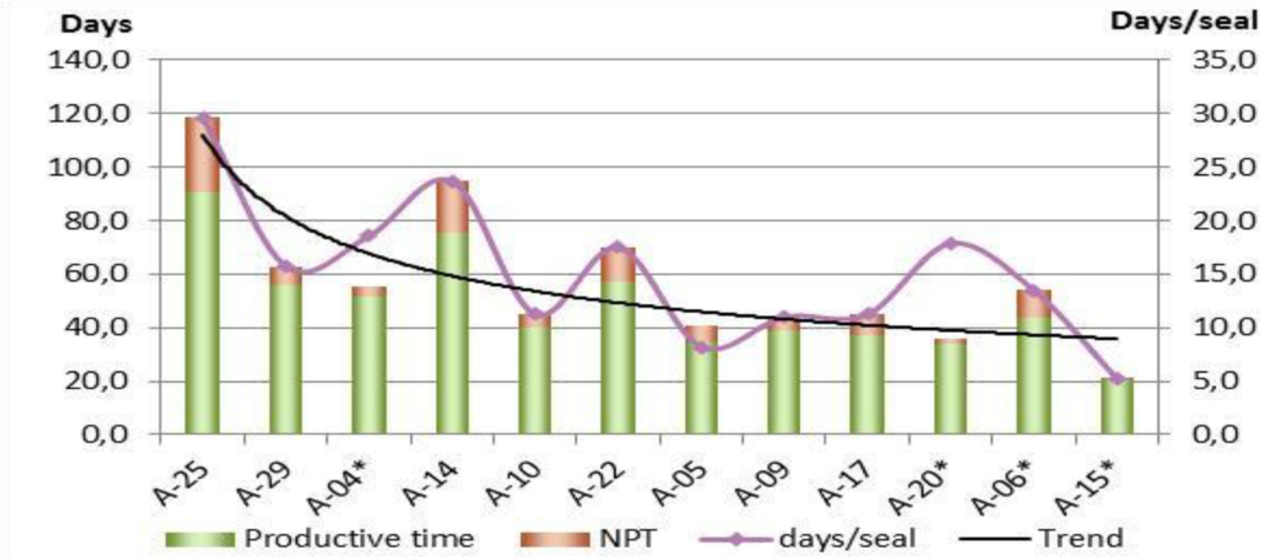

Figure 25 - Duration development during P&A campaign on the NCS [32]

The regular advantage of learning effects in a P&A campaign is only one part of the total advantage DWP can achieve by being a specialized unit. Since it is performing within the same type of operation for a long period, the advantage from one campaign can be developed to the next campaigns. The work can potentially be conducted faster, with better quality and safety. A regular J/U unit, such as CJ70, would also benefit from learning effects within a campaign, similarly to DWP. Since it is designed to drill and complete wells, it will most likely not conduct P&A campaigns continuously. Therefore, it will not gain the same efficiency improvements from learning effects as DWP, performing the same type of operation from one campaign to another. The campaign-to-campaign learning effects have not been documented, but may have substantial improvement potential. Since there is no data from the "Final Well Reports" of which order the P&A campaign have been conducted, learning effects has not been included in the analysis.

7.1. Limitations

Though the present analysis provides some insight of the profitability of DWP compared to a regular J/U, it is not entirely beyond reproach. A concern of concept studies, is that it may be subjected to common methodological bias. Since the study is conducted practically independent of any company, the analysis should not be affected by any exterior source. The study has attempted to be neutral by not favouring any of the compared units. The uncertainties related to the analysis have been displayed where they may be present.

The calculations for the study are only based on two specific well operations within the same field, and does not necessary symbol the scope for all the wells included in the market potential. The two selected operations can also be looked upon as relatively low difficulty well examples, and may not give a truthful representation of the total cost. The presented values assume that an average of the two wells can be regarded as representative for the wells within the scope of the unit. The original durations from the “Final Well Reports” can be regarded as longer than a current average of P&A duration on the NCS. This may be explained by the technology and methodology advances which have been developed later years. The analysis would be different for cases with increasingly demanding P&A scope who would include a greater usage of heavier operations such as casing milling, section milling operations or retrieval of short sections due to stuck tubing/casing. The unit is well suited to do such operations since it includes double swarf handling units, which often can be a limit during such operations.

The results of the analysis will be strongly dependent of the rig rental rates and overhead expenses selected. In a crowded rig market, total expenses for the two units would start to equalize, and opposite in a mature rig market. The assumptions made with regards to overhead expenses for the two units can be questioned, but without discretizing it to every detail, it will not be possible to calculate more accurate than performed. The market potential calculation is only based on the platform wells on the NCS within the unit specifications. It abstains the potential SOW within subsea fields, who is part of the total market potential. Since the two “Final Well Reports” are platform wells, it would be incorrect to include the subsea wells to the market potential calculation, even though it is within the unit scope.

8. Conclusion and Recommendations

8.1. Conclusion.

The study has demonstrated that all the solutions of DWP provides better economics than a standard J/U rig during P&A operations of the two specified well examples. The analysis has been conducted with an assumption of normal rig activity and average rig rates, to avoid favouring any of the two units. The results of the study show that DWP is possible to perform a P&A operation within the same time schedule of a regular J/U rig, with a scaled down derrick and by inclusion of CT and WL where applicable. The profitability of DWP-CT is ultimately reduced to the ratio between the rental rates where the profit $\frac{330\text{k}\,USD/day - 225\text{k}\,USD/day}{330\text{k}\,USD/day} \approx 32\%$, which is reflected in Table 12 and Table 13. As long as the well complexity is comparable to the two gathered P&A operations where duration of the operation remains practically unchanged, all potential profits will be settled by daily rental rates.

The study also indicates that the hypothesis that utilization of the most appropriate equipment for all sequences necessary is not the best solution for all well examples. Even though DWP-CT reduces the number of hours used to perform the operations, it does not provide substantial better economics than the other two compared designs. To be able to defend the use of CT in a P&A operation, the added efficiency must compensate for the extra cost of mobilizing the equipment and personnel. The problem with a P&A operation is that there is a lot of time being used stationary in the well. The advantage of fast tripping is thus not being utilized to its fullest. The relative cost difference between DWP-CT and DWP-SB are $\frac{225\text{k USD/day}}{205\text{k USD/day}} \approx 10\%$, whilst the operations is respectively $\left(1 - \frac{721{,}6\text{ hrs}}{802{,}2\text{ hrs}}\right) = 10{,}7\%$ and $\left(1 - \frac{645{,}2\text{ hrs}}{681{,}3\text{ hrs}}\right) = 5{,}3\%$ more efficient (Table 8-Table 11). This reveals the cost/benefit of the DWP-CT to not be satisfactory compared to DWP-SB for well example 2. Both solutions will contribute in cost savings compared to a regular J/U rig, but for P&A operations the setback solution is the preferred setup for the second well.

Even though it is a tough decision to select which unit that should be used for an operation, DWP-CT might be best suited for the future. The industry is currently motivated to become rig-less, and there will be developed new tools to conduct a larger proportion of a P&A scope with CT and WL. The concept design, DWP-CT, encourage to utilize this equipment more frequently. Fitting the unit with coiled tubing also has a large potential in other well activities within the unit spec, such as workovers and interventions. Due to high utilization of CT and WL in such operations, it should provide an adequate cost/benefit ratio. With the industry-focus to develop more technologies to increase rig-less P&A scope, DWP-CT will be best suited for the future needs. Inclusion of the unit will also be one step closer to achieve "Norwegian Oil and Gas" ambitions of a rig-less P&A future.

As long as the rig market maintain at a level resulting in rig rental rates of drilling units above 200k USD/day, inclusion of DWP will result in cost savings. There are several aspects of the unit that can result in even larger savings that hasn't been included to the analysis. The study has been focusing on the P&A scope of the unit, but it is important to not forget that the unit can conduct several other activities with the planned equipment on board. An advantage that haven't got a lot of attention in the analysis is the 1250 mT heavy lift offshore crane to be fitted on board. The crane reveals possibilities no other rig on the market can offer. The opportunity to perform all downhole operations and continue with platform decommissioning is a benefit that should not be overlooked.

P&A has become a hot topic within the industry the past years. There is a large focus and desire to move P&A operations rig-less. By the meaning of the words, the ambition is to conduct P&A operations without DP in the future. For subsea wells, this will mean P&A with RLWI vessels, whilst platform wells must be conducted with modular rigs or new developments. With the current technology on hand, it is not possible to conduct all P&A operations on the shelf without DP present. Technology advancements may open the possibilities to implement CT and WL in heavier operations in the future. The innovative WOR design by Dwellop can be regarded as a step closer to the goal of rig-less P&A operations of platform wells on the NCS.

8.2. Recommendations

During the process of considering the purpose-built P&A concept DWP, there have been encountered several key-points the writer would like to address. The recommendations are based on the analysis and personal meetings with the industry. Some of the points is already planned to be executed within the company, but are included to increase the focus on the key-points.

The unit is supposed to be designed as a rig built to conduct lighter operations such as P&A, workovers and interventions, but there is still a great focus on DP-solutions and drilling equipment to accommodate DP utilization. The focus should be pointed to WL and CT, to include the equipment with the system. The unit is supposed to work as a class B rig, not a bad class C rig. Class B rigs were implemented as a wish by Statoil to have alternatives to conduct light rig operations. There have been introduced a couple of units for subsea wells, but there are still no class B unit for platform wells. This is where Dwellop can be pioneers, by prioritizing this concept to the fullest.

To be able to have a well-functioning system, there must be put large efforts to improve the inclusion of WL and CT to the unit. The systems should be the backbone of the rig, with all systems implemented to the cantilever. The present CT design is a good start, but experienced CT personnel and designers should be included to the further design phase of the unit, to tailor it to include CT in the best way. Points that should be considered is: placement of CT reel and control unit for handling of the system. It should also be put efforts to include WL in a better way than the present design. These two tools are part of the solution for the industry, wishing to move more operations rig-less. To be able to conduct a full P&A operation it is also important that the unit is equipped with a large enough BOP to be able to cope with 13 3/8'' intermediate casing retrieval. Todays designed BOP is too small to handle casings of this size.

To be able to maintain the unit costs low, it has been discussed to cross train personnel on board to be able to handle the different equipment. The challenges by including much extra standard equipment on board a vessel is to maintain a low POB without retaining full capability and competence on board. Cross-training of people could be a reality with good communication between service providers and dedicated training programs. The operational impact would be a reduction in operational time for commonly performed sequences, due to increased efficiency through a seamless collaboration between the different crew and equipment. Cross training of personnel enables simultaneous operations, reducing campaign lifetimes and overhead expenses due to reduction of POB. With a better understanding of how the different equipment can be run together and its limits, the operation can be conducted with a high focus on safety with a rapid implementation of lessons learned [33].

To be able to introduce a unit such as DWP to the NCS, it is necessary for the company to ensure long-term contracts to be able to support the investment. In today's market, there are probably no single operator on the shelf that are prepared to hire a specialized unit for a long-term contract single-handed. The companies have single wells and platforms spread on the shelf that are ready to be P&A'ed, and cannot employ a unit single handed over a long period. Some operators have whole fields or platforms that will need to be P&A'd the next years in a campaign, where the unit would be well purposed for this job. In 2007, a company called Rig Management Norway (RMN) were established to facilitate consortium solutions for drilling rigs on the shelf. Several operators went together and hired rigs in a rig consortium. The objective was to share a long-term contract between several consortium members with options to use the rig for a certain period of time during the contract. This solution made it possible for rigs-owners to get long term stable drilling contracts, where the operators got access to both rig capacity and third party services for their operations. The initiators of RMN have today started a company called Advanced Petroleum Consultants (APC), and have ambitions to facilitate rig consortiums adapted for P&A operations. A problem with rig consortiums and J/U rigs it the mobility of the unit. J/U rigs are prone to weather during transportation. There have been cases where units have been waiting several weeks for a weather window to be able to settle to a platform. These scenarios occur most often during the winter season with more swell, waves and wind. To be able to ensure operations during the winter season, there could be a solution to keep the unit employed with a P&A campaign, without the need to transit between platforms. During the summer period, the unit can conduct P&A, workovers and interventions of single wells with significant better weather, and smaller probability for unproductivity during transit.

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10. Appendices
10.1. Appendix A

Equipment	***Capacity/figure***
Cantilever	
Longitudinal skidding	120 ft (36,5m)
Transverse skidding	+/- 18 ft (5,5m) from centre
Top Drive	
Max pull	250 MT
Max torque	32 kft/lbs.
Max RPM	200 rpm
Torque Wrench Makeup/Break out torque	80 kft/lbs.
Lifting height	17 meters free lifting height below elevator
Drillfloor equipment	
Utility Winch	6 t, 40m wire
Man rider Winch	150 kg capacity
Iron Roughneck	2 7/8" - 10", MU/BO torque 100kft/lbs
Cat Head	1x 140Nm
Back up posts	2 e.a for manual rig tongs
Mud bucket	Manual with flow line connection of returns
False rotary table size	49 ½” adapter ring to fit 37 ½” master bushing
Mud system	
Mud pit capacity	225 m3 total volume – Approx. Agitators, level transmitters included in all pits
Kill/Choke Standpipe manifold/poor boy degasser	345 Bar (5000 psi) system incl. cement manifold
Degasser	1500 gpm
Mud pumps	2 x 1300hp
Shale shakers	5500 l/m
Shaker pit	15m3
Swarf units	2 ea.
Trip Tank	10 m3
Trip tank pumps	2 ea.
Mix pump	1 ea.
Transfer pump	1 ea.
Supercharge pump	2 ea.
Mud Mix system	1 ea.
Pipe Handling	
Tripping speed	320 meters/hour (1050 ft. /hr.)
Pipe Handling crane	2 7/8" - 13 3/8" - 1,5MT capacity
Catwalk	2 7/8” – 14” 40-60 pipes/hours
Pipe deck storage	3200 meters of 5” Range 2 drill pipe, additional deck space on jack up deck if required (casing storage).

Table 14 - DWP equipment details

10.2. Appendix B

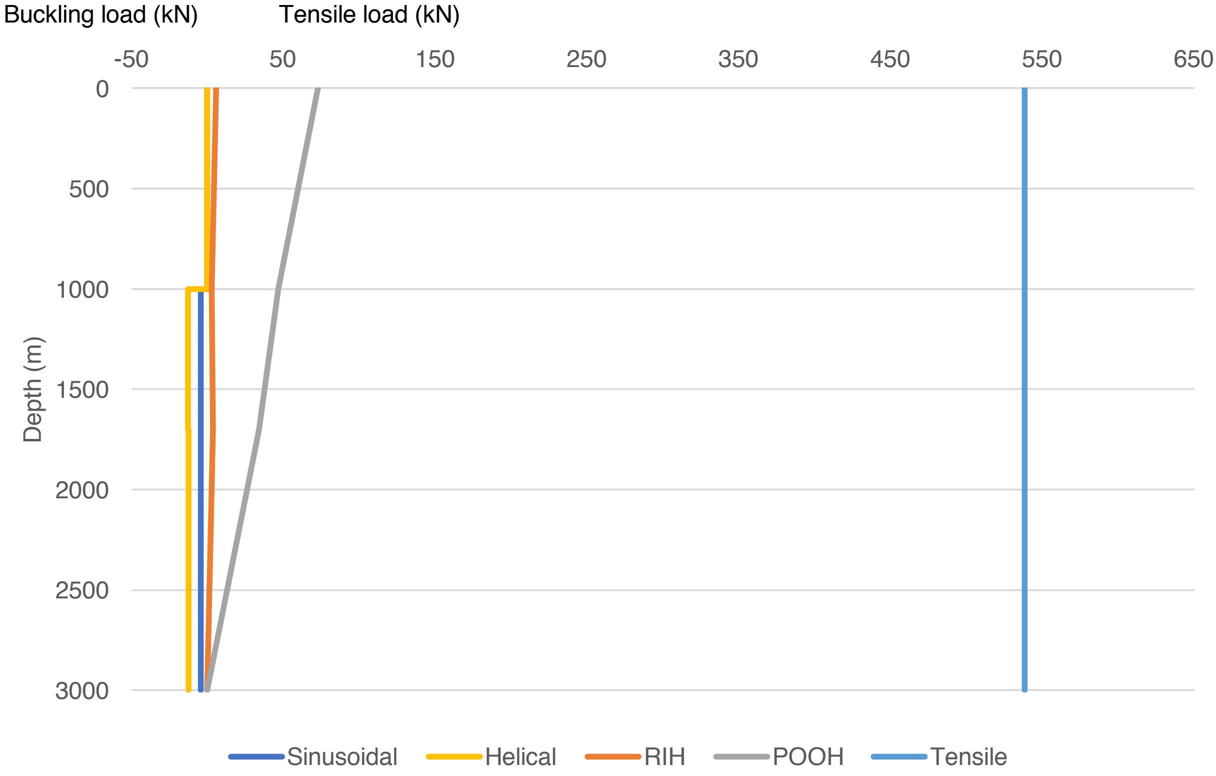

Figure 26 – Tension/buckling analysis - 2 3/8''CT

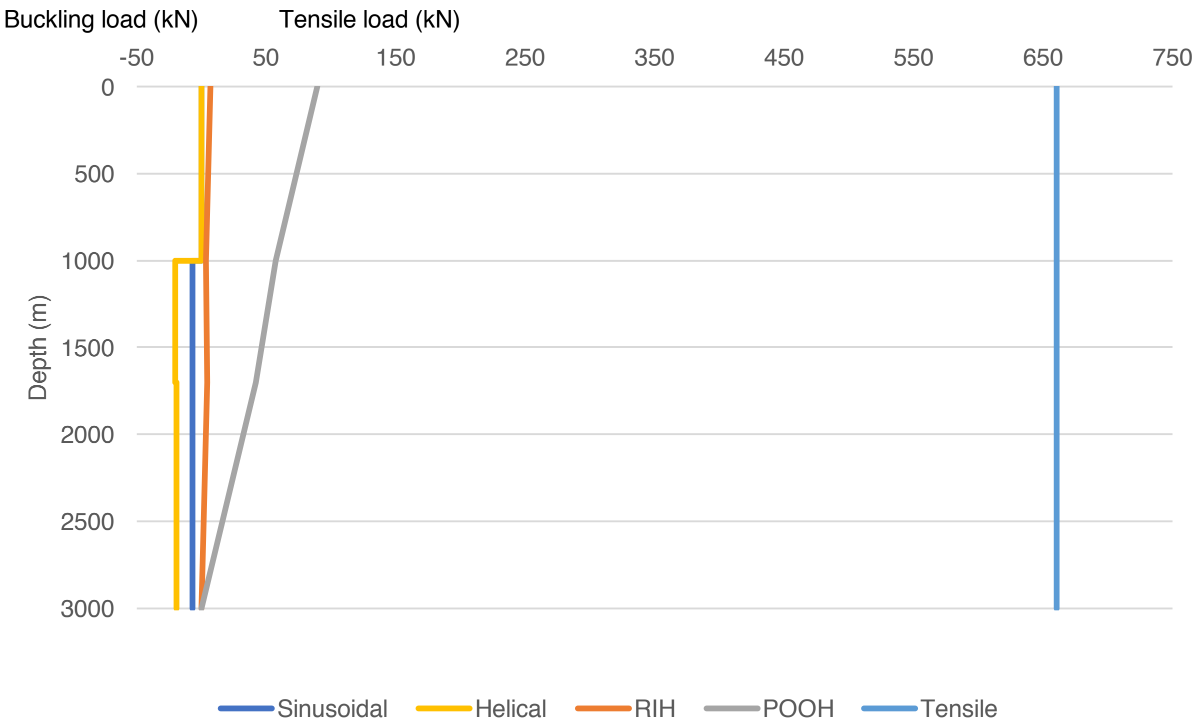

Figure 27 – Tension/buckling analysis - 2 7/8'' CT

10.3. Appendix C

Well 1					
Operation	**Duration [hrs]**	**Acc duration [days]**	**Operation**	**Duration [hrs]**	**Acc duration [days]**
			6 - Establish second PWC barrier	**98,0**	**4,1**
			M/U perforation guns and RIH	9,0	13,4
1 - Rig work	**56,1**	**2,3**	Perforate 50 m interval	2,0	13,5
Skid rig	10,5	0,4	POOH with perf guns and L/D	9,0	13,9
WOW due to strong winds	7,5	0,8	M/U second set of perf. guns and RIH	9,0	14,3
Continue to skid rig	8,3	1,1	Perforate 50 m interval	2,0	14,3
N/D XMT, set junk catcher	9,0	1,5	POOH with perf guns and L/D	9,0	14,7
N/U drilling BOP and riser, retrieve junk catcher, test BOP	20,8	2,3	M/U and RIH with HydraHemera tool	10,0	15,1
			Circulate and condition mud and wash cementing interval	15,0	15,8
			Displace spacer	1,0	15,8
			Perform cement job	1,0	15,8
2 - Pull tubing and clean well	**87,5**	**3,6**	POOH to TOC and circulate well clean	2,0	15,9
P/U and RIH with spear and pull tubing	37,5	3,9	WOC time: while waiting POOH w/HydraHemera & RIH with tagging BHA	19,0	16,7
RIH with 8 1/2'' BHA	3,9	4,1	Tag cement and POOH	10,0	17,1
Clean 9 5/8'' casing	23,6	5,0	Contingency: Cement plug failure - New HydraHemera job	0,0	17,1
Circulate and condition 1,20 sg WBM. POOH	22,5	6,0			
			7 - Retrieve C-section	**47,0**	**2,0**
			N/D BOP & riser	10,0	17,6
			N/D C-Section, N/U Riser & BOP	24,0	18,6
3 - Establish reservoir barrier	**53,7**	**2,2**	Test BOP	13,0	19,1
RIH with cement stinger. P/U 12 jnts of 1/2'' DP while RIH.	12,5	6,5			
Set +/- 200 m cement plug in 9 5/8'' casing top of deep set plug	6,8	6,8	**8 - Cut and pull 9 5/8'' casing**	**58,0**	**2,4**
WOC. Tag cement plug	13,8	7,4	RIH and cut 9 5⁄8" casing at 3200' , POOH	14,0	19,7
Displace well to SW and then to treated injection water	4,8	7,6	R/U casing equipment	4,0	19,8
POOH w/cmt stinger	15,8	8,2	Retrieve 9 5⁄8" casing down to 3200'	36,0	21,3
			R/D casing equipment	4,0	21,5
			9 - Retrieve B-section	**73,0**	**3,0**
4 - Set base for PWC barriers	**15,0**	**0,6**	N/D BOP, N/D B-section, N/U 21 1⁄4" BOP	72,0	24,5
M/U EZSV	1,0	8,3	Connection test BOP	1,0	24,6
RIH, set EZSV and POOH	13,0	8,8			
L/D EZSV RT	1,0	8,8	**10 - Cut and pull 13 3/8'' casing**	**52,0**	**2,2**
			RIH and cut 13 3⁄8" casing at 3000', POOH	8,0	24,9
			R/U casing equipment	4,0	25,1
			Retrieve 13 3⁄8" casing down to 3000'	36,0	26,6
5 - Establish first PWC barrier	**101,0**	**4,2**	R/D casing equipment	4,0	26,7
M/U Perforation guns and RIH	9,0	9,2			
Perforate 50 m interval	2,0	9,3	**11 - Establish open hole to surface barrier**	**55,0**	**2,3**
POOH with perf guns and L/D	9,0	9,7	Perform 20" casing clean-up run	8,0	27,1
M/U second set of perf. guns and RIH	9,0	10,1	M/U, RIH with 20" EZSV to approx 2300'	10,0	27,5
Perforate 50 m interval	2,0	10,1	Set 20" EZSV at approx 2300', tag / pressure test EZSV	5,0	27,7
POOH with perf guns and L/D	9,0	10,5	POOH and L/D 20" EZSV RT	4,0	27,8
M/U and RIH with HydraHemera tool	10,0	10,9	RIH with cement string to 2 300'	14,0	28,4
Circulate and condition mud and wash cementing interval	15,0	11,6	Set 50m cement plug in 20" casing	4,0	28,6
Displace spacer	1,0	11,6	POOH with cement string	10,0	29,0
Perform cement job	1,0	11,6			
POOH to TOC and circulate well clean	2,0	11,7	**12 - Finalizing operations**	**39,0**	**1,6**
POOH w/Hydrahemera	2,8	11,8	Displace well to sea water	10,0	29,4
WOC time: RIH with tagging BHA	17,2	12,6	N/D BOP, install cover	24,0	30,4
Dress off and tag cement (until 10ton) and POOH	12,0	13,1	Prepare to skid rig to next well	5,0	30,6
			Total	Acc hrs	Acc days
				735,3	**30,6**

Table 15 – Operational details – Well 1

10.4. Appendix D

Well 2					
Operation	**Duration [hrs]**	**Acc duration [days]**	**Operation**	**Duration [hrs]**	**Acc duration [days]**
			6 - Establish 13 3/8'' barrier	**105,0**	**4,4**
1 - Rig work	**50,0**	**2,1**	Perform 13 3⁄8" casing clean-up run	18,0	13,6
N/D flowline and instrumentation	10,0	0,4	R/U WL equipment	2,0	13,6
Skid rig	8,0	0,8	RIH with USIT/CBL	1,0	13,7
N/D XMT, set junk catcher	8,0	1,1	Log 13 3⁄8" casing	13,0	14,2
N/U drilling BOP and riser, retrieve junk catcher, test BOP	24,0	2,1	R/D WL equipment	2,0	14,3
			M/U, RIH with 13 3⁄8" EZSV to approx 5800'	16,0	15,0
			Set 13 3⁄8" EZSV at approx 5800', tag / pressure test EZSV	8,0	15,3
2 - Pull tubing and clean well	**93,3**	**3,9**	POOH and L/D 13 3⁄8" EZSV RT	5,0	15,5
P/U and RIH with spear and pull tubing	36,0	3,6	RIH with cement string to 5800'	20,0	16,3
Contingency: Cut and pull tubing	0,0	3,6	Set 50m cement plug in 13 3/8" casing	4,0	16,5
Perform casing clean-up run	30,0	4,8	POOH with cement string	16,0	17,2
R/U WL equipment	2,0	4,9	Contingency: Establish barrier across 13 3⁄8" casing	0,0	17,2
RIH with USIT/CBL	1,7	5,0			
Log 9 5/8" casing	21,7	5,9	**7 - Retrieve B-section**	**81,0**	**3,4**
R/D WL equipment	2,0	6,0	M/U, RIH and set 13 3⁄8" shallow plug to section	8,0	17,5
			N/D BOP, N/D B-section, N/U 21 1⁄4" BOP	72,0	20,5
			Connection test BOP	1,0	20,6
3 - Establish reservoir barrier	**50,0**	**2,1**			
RIH with 3 1⁄2" DP cement string to 10 000'	24,0	7,0	**8 - Cut and pull 13 3/8'' casing**	**58,0**	**2,4**
Set +/- 200 m cement plug in 7" liner on top EZSV	6,0	7,2	RIH with retrieving tool, POOH with 13 3⁄8" shallow set plug	6,0	20,8
POOH with cement string	20,0	8,1	RIH and cut 13 3⁄8" casing at 3000', POOH	8,0	21,1
Contingency: Establish barrier across 7" liner	0,0	8,1	R/U casing equipment	4,0	21,3
			Retrieve 13 3⁄8" casing down to 3000'	36,0	22,8
			R/D casing equipment	4,0	23,0
4 - Retrieve C-section	**33,0**	**1,4**	**9 - Establish open hole to surface barrier**	**55,0**	**2,3**
M/U, RIH and set 9 5⁄8" shallow set plug to N/D C-section	12,0	8,6	Perform 20" casing clean-up run	8,0	23,3
N/D BOP, N/D C-section, N/U BOP	20,0	9,4	M/U, RIH with 20" EZSV to approx 2300'	10,0	23,7
Connection test BOP to 300 bar	1,0	9,4	Set 20" EZSV at approx 2300', tag / pressure test EZSV	5,0	23,9
			POOH and L/D 20" EZSV RT	4,0	24,1
			RIH with cement string to 2 300'	14,0	24,7
			Set 50m cement plug in 20" casing	4,0	24,8
5 - Cut and pull 9 5/8'' casing	**81,0**	**3,4**	POOH with cement string	10,0	25,3
RIH with retriving tool, POOH with 9 5⁄8" shallow set plug	7,0	9,7			
RIH and cut 9 5⁄8" casing at 6000' , POOH	14,0	10,3	**10 - Finalizing operations**	**39,0**	**1,6**
R/U casing equipment	4,0	10,5	Displace well to sea water	10,0	25,7
Retrieve 9 5⁄8" casing down to 6000'	52,0	12,6	N/D BOP, install cover	24,0	26,7
R/D casing equipment	4,0	12,8	Prepare to skid rig to next well	5,0	26,9
			Total	Acc hrs	Acc days
				645,3	**26,9**

Table 16 - Operational details - Well 2