NTNU – Trondheim
Norwegian University of
Science and Technology

Subsea Well Intervention in the North Sea

Learning from Mistakes and Experience

Are Folkestad Kile

Earth Sciences and Petroleum Engineering
Submission date: June 2012
Supervisor: Sigbjørn Sangesland, IPT
Co-supervisor: Thore Bergsaker, BP Norge

Norwegian University of Science and Technology
Department of Petroleum Engineering and Applied Geophysics

TPG 4910

Master of Science Thesis

Subsea Well Intervention in the North Sea

Learning From Mistakes and Experience

Are Folkestad Kile

Trondheim - June 2012

Norwegian University of Science and Technology

Faculty of Engineering Science and Technology

Department of Petroleum Engineering and Applied Geophysics

NTNU
Norges Teknisk-Naturvitenskapelige Universitet
Norwegian University of Science and Technology
Studieprogram i Geofag og petroleumsteknologi
Study Programme in Earth Sciences and Petroleum Engineering

Fakultet for Ingeniørvitenskap og Teknologi
Faculty of Engineering and Technology

Institutt for Petroleumsteknologi og Anvendt Geofysikk
Department of Petroleum Engineering and Applied Geophysics

HOVEDOPPGAVE/DIPLOMA THESIS/MASTER OF SCIENCE THESIS

Kandidatens navn/The candidate's name:	*Are Folkestad Kile*
Oppgavens tittel, norsk/Title of Thesis, Norwegian:	*Undervanns brønnintervensjon i Nordsjøen – Læring fra feil og erfaring*
Oppgavens tittel, engelsk/Title of Thesis, English	*Subsea Well Intervention in the North Sea – Learning from Mistakes and Experience*

Utfyllende tekst/Extended text:

BP Norway is well versed in well intervention from fixed platforms. The present Skarv field development will however require future well interventions to take place from different floating vessels and rigs. In order to properly prepare the Well Intervention department and management system for the coming challenges, a broad definition of subsea intervention practices and experience needs to be developed and described. Subsea wells are expensive to intervene with conventional rigs so the more cost-efficient Light Well Intervention (LWI) alternative should be considered. Unplanned events causing delays or non-productive time (NPT) is sought to be reduced by analysing previous incidents and by applying risk management as a tool to increase the operational factor (uptime vs. downtime) and economics of subsea well intervention operations.

Task:

1) Describe subsea intervention practices, technology and experience.
2) Elaborate on LWI vessels and Riserless Light Well Intervention (RLWI) technology.
3) Group and analyse lessons learnt from the North Sea. Explain and show by example how risk management can be used as a tool to reduce unexpected downtime.

Supervisor	*Sigbjørn Sangesland*
Co-supervisor (BP)	*Thore Bergsaker*
Studieretning/Area of specialisation:	*Petroleum Engineering, Drilling Technology*
Fagområde/Combination of subject:	*Drilling*
Tidsrom/Time interval:	*January 16 – June 27, 2012*

……………………………
Sigbjørn Sangesland

Preface and acknowledgements

This diploma thesis has been written as a part of my Master of Science degree, and is the conclusion of my five year master's degree programme "Petroleum Geosciences and Engineering" at the Norwegian University of Science and Technology in Trondheim, Norway. The work was conducted in BP's offices in Stavanger during normal working hours and weekends the first half of 2012.

I would like to thank *BP Norway* for providing excellent framework conditions for my diploma thesis. The extent of BP data and information is vast, the professional environment is including and there is always somewhere to seek solutions to any technical challenge. In addition to this, BP provided a foundation outside of the office making me able to completely focus on the work.

I would also like to thank my BP supervisor *Thore Bergsaker* for inviting me into his team and for always keeping the door open to answer any question or offer guidance. Because of him, I were among other things able to travel to Aberdeen to meet thesis subject BP experts which facilitated the work tremendously and panned out to be a unique learning experience.

In Aberdeen I spent close to a week with BP expert *Jamie Lundie*, a truly knowledgeable and pleasant individual. I would like to thank him for all his help and especially for his patience during discussions and in dealing with all my questions and thoughts. I want to recognise *BP UK* for making this week possible.

Thank you to my University supervisor Professor Sigbjørn Sangesland for excellent academic guidance throughout the whole period. The meetings with him were always constructive and key to fulfill all requirements and University expectations. Although only briefly referenced to in this thesis, studying the lecture material from the "Subsea Production Systems" subject he teaches gave me a good basis for the thesis work.

I offer my deepest gratitude to my father and respected industry professional *Hogne Jakob Kile*. With what seems like endless wisdom, creativity and patience he is always willing to help. Our countless discussions during this period have led way for new sections in the thesis text, and his input has been greatly appreciated. He is a good motivator when needed and an exceptional role model in general, both professionally and in life.

Are Folkestad Kile
Stavanger, June 2012

Executive Summary

BP Norway is well versed in well intervention from fixed platforms. The present Skarv field development will however require future subsea well interventions to take place from different floating vessels. BP has extensive experience from subsea fields outside of Norway, and it is necessary to ensure that the planning and preparations for such activities in Norway are fully up to speed with company competence. This thesis seeks to act as reference work for anyone interested in learning about subsea well intervention in BP Norway, but should not be mistaken for purely theoretical work. The overall goal is to assess how future subsea well intervention operations on Skarv can be performed, optimised and incorporate all BP learning from previous operations in the North Sea, thus contribute to increased hydrocarbon recovery from the Norwegian continental shelf.

In order to properly prepare the well intervention department and management systems for the coming challenges, a broad definition of subsea intervention practices, technology and experience have been described. Subsea wells are expensive to intervene with conventional rigs so the more cost-effective Light Well Intervention (LWI) alternative has been selected as a focus area. Even LWI vessels are expensive machinery so malpractices during operational execution may compromise the good economics of well interventions.

The in depth study is focused on experienced unplanned events causing delays or non-productive time (NPT) during operations and thereby reducing operational efficiency. A powerful tool to increase the operation factor (uptime vs. downtime) and economics of subsea interventions is to proactively apply risk management techniques, hence this subject is also incorporated in the in depth study. The thesis is operationally orientated and a wide range of real data has been analysed, including but not limited to operational daily reports, end of well reports, after action reviews, risk assessments, operational guidelines, procedures, practices and investigation reports. The BP advisory team was consistently involved in the process and in addition to analysing documents, expert interviews were conducted.

The analysis is by reasoning of the above concentrated on all operations conducted from the three LWI vessels BP had in operation in the North Sea in the time period 2009-2011. One of the most important findings is that around 80 % of all lessons learnt stems from “Planning”, “Equipment” or “Operations”, suggesting this should be the main arena for organisational learning focus and future improvement efforts. Among a number of comparable reports, the following example from the LWI vessel Island Constructor operating on the Devenick field in 2011 has helped in narrowing down one of the key causes behind the high number of incidents within the “Equipment” and “Operations” categories to interface clashes: “Unable to land off tree running tool on the subsea tree due to interface issues between the hydraulic couplers. Various attempts to land the tree running tool anyway lead to wear on equipment and 3 coupler shrouds came free.”

Several similar underlying causes have been identified based on commonalities found when cross referencing all the subsea intervention operational lessons for different phases including “Planning”, “Rig Up”, “Personnel”, “Communication” and “Miscellaneous” in addition to the above mentioned categories. Some of the documented lessons learnt are repeated at other vessels later in time, questioning the ability to actually benefit from recording these lessons.

A recommended risk assessment template has been established in order to assist focus for future planning of similar operations in Norwegian waters. Implementation of the template will improve operational efficiency, reduce unwanted downtime and make BP among the "best in class" when it comes to practical risk management and organisational learning within subsea LWI operations.

Further work should be done to include an even more comprehensive data study to uncover trends that might have gone under the radar. Further work should also focus on providing an effective permanent organisational learning platform to ensure unwanted events do not repeat themselves and that all relevant lessons learnt are indeed incorporated in future operations to be able to take full advantage of previous successes and failures. All BP experience should be gathered and processed to get a total experience and risk data bank for these operations. Recommended measures from the risk register should be transformed to updated programmes and procedures.

Further work should also seek implementation of the new recommended risk register approach proposed in this thesis for subsea well interventions in the BP organisation.

Sammendrag (Executive Summary in Norwegian)

BP Norge har lang erfaring fra brønnintervensjoner utført på forskjellige plattformer. Utbyggingen av Skarvfeltet vil imidlertid føre til at fremtidige undervanns brønnintervensjoner må utføres fra forskjellige flytende fartøy. BP har lang erfaring fra undervanns brønnintervensjon utenfor Norge, og det er nødvendig å sikre at planleggingen og forberedelsene til slike aktiviteter i Norge er fullt på høyde med selskapets globale kompetanse. Denne diplomoppgaven søker å fungere som et oppslagsverk for de som er interessert i å lære om undervanns brønnintervensjon i BP Norge, men bør ikke anses som et rent litterært verk. Hovedmålsettingen er å evaluere hvordan fremtidige undervanns brønnintervensjoner på Skarv kan bli utført, optimalisert og inkorporere all BP lærdom fra tidligere operasjoner i Nordsjøen, og dermed bidra til økt utnyttelsesgrad av hydrokarboner på norsk sokkel.

For å forberede brønnintervensjonsavdelingen og styringssystemene skikkelig på de kommende utfordringene, har en bred definisjon av undervannsintervensjons praksiser, teknologi og erfaringer blitt beskrevet. Undervannsbrønner er dyre å intervenere med konvensjonelle rigger, så det mer kostnadseffektive alternativet «Lett Brønnintervensjon» har blitt valgt som et fokusområde. Lette brønnintervensjonsfartøy er også dyre i drift så feilgrep under operasjonell utførelse kan få økonomiske konsekvenser som undergraver hele formålet med brønnintervensjonen.

Dybdestudiet er fokusert på erfarte ikke planlagte hendelser som førte til forsinkelser eller ikke produktiv tid og dermed redusert operasjonell effektivitet. Et sterkt våpen for å øke den operasjonelle faktoren (oppetid vs. nedetid) og økonomien til undervanns brønnintervensjoner er proaktiv bruk av risikostyringsteknikker, så dette temaet er derfor også tatt med i dybdestudien. Diplomoppgaven er operasjonelt fokusert og et bredt spekter av bakgrunnsdokumentasjon har blitt analysert inkludert men ikke begrenset til daglige operasjonsrapporter, sluttrapporter, etter-aksjon rapporter, risikovurderinger, operasjonelle retningslinjer, prosedyrer, praksiser og etterforskningsrapporter. Rådgivningsteamet fra BP var til enhver tid involvert i prosessen og i tillegg til å analysere dokumenter, ble det utført ekspertintervjuer.

Analysen er med bakgrunn i det overstående konsentrert rundt alle operasjoner utført fra de tre lett brønnintervensjonsfartøyene BP hadde i operasjon i Nordsjøen i tidsperioden 2009-2011. Et av de viktigste funnene er at rundt 80 % av all læring kom fra «Planlegging», «Utstyr», eller «Operasjon», noe som indikerer at dette bør være hovedfokusområdet for organisatorisk læring og fremtidig forbedringsarbeid. Blant mange av rapportene som omhandlet det samme emnet, har følgende eksempel fra fartøyets «Island Constructor» operasjon på Devenickfeltet i 2011 bidratt til å identifisere en av nøkkelårsakene til det høye antallet hendelser innen «Utstyr» og «Operasjon» kategoriene som grenseflateinkompatibilitet: «Ute av stand til å lande treløfteutstyret på undervannstreet på grunn av grenseflateproblemer mellom de hydrauliske koblingene. Flere forsøk på å lande utstyret uansett førte til slitasje på utstyret og 3 koblingshylser løsnet.»

Flere lignende underliggende årsaker har blitt identifisert basert på likheter som er funnet ved kryssreferering av all operasjonell læring fra forskjellige faser inkludert «Planlegging», «Opprigging», «Personell», «Kommunikasjon» og «Blandet» i tillegg til de tidligere nevnte kategoriene.

Deler av tidligere dokumentert negativ læring har blitt gjentatt senere på andre fartøy, noe som stiller spørsmålstegn ved evnen av å dra nytte av registrerte lærdommer.

En anbefalt risikovurderingsmal har blitt opprettet for å assistere fokus for fremtidig planlegging av lignende operasjoner i norske farvann. Implementering av denne malen vil forbedre den operasjonelle effektiviteten, redusere uønsket nedetid og gjøre BP blant de «beste i klassen» når det kommer til praktisk risikostyring og organisatorisk læring innen undervanns lett brønnintervensjonsoperasjoner.

Videre arbeid bør inneholde enda mer data for å avdekke trender som kanskje ikke har blitt identifisert her. Videre arbeid bør også fokusere på å utarbeide en effektiv og permanent organisatorisk læringsplattform for å sikre at uønskede hendelser ikke gjentar seg og at all relevant læring er inkorporert i fremtidige operasjoner for å utnytte tidligere suksesser og nedturer fullstendig. All BP erfaring bør bli samlet og prosessert for å utarbeide en total erfarings- og risikodatabase for undervanns brønnintervensjonsoperasjoner. Anbefalte forholdsregler fra risikoregisteret bør inkluderes i programmer og prosedyrer.

Videre arbeid bør søke å implementere den nye risikovurderingsmalen som er foreslått i denne diplomoppgaven for bruk i undervanns brønnintervensjonsoperasjoner i BP organisasjonen.

Contents

List of Figures

List of Tables

1.0 Introduction

The first subsea wells were completed in the 1960s and today more than four thousand are found worldwide with numbers quickly rising. The value created by these wells account for billions of dollars and the subsea sphere has by some been announced as conquered territory. Yet, subsea wells keep underperforming dry tree (platform) wells substantially and with increasing water depths, new challenges continually keep piling up. Hydrocarbon recovery rates from subsea developments are consistently lower than on fixed platforms, sometimes rendering difference in ultimate recovery factor from the reservoir as high as 35%. The foremost reason for this discrepancy is the lack of regular intervention work performed on subsea wells. While it is cheaper to access a well with the wellhead (WH) and Christmas tree (XMT) located on a platform deck, the cost related to accessing a subsea well sky rockets by comparison. Historically, well interventions on subsea wells have been done by conventional drilling rigs such as semi-submersibles or jack ups. The large cost of mobilising such rigs has led to many wells being left unattended for too long, low-producing or merely shut in due to integrity concerns. They are simply de-prioritised. The cost of intervention has been high and other tasks such as drilling new wells or restoring integrity have had priority. The latter receiving much more attention lately.

Oil production is declining and it is the production of gas that keeps the number of oil equivalents from the Norwegian Continental Shelf (NCS) relatively stable. The cost related to offshore activity has increased much more than inflation on mainland Norway. The key to maintain the current production level on the NCS is to secure and increase the recovery from existing fields while opening new fields and exploration areas for production.

Well intervention operations will be one of the central contributors in realising the hydrocarbon potential and aiming for maximum value creation. Well intervention normally leads to more production immediately, and enables planning of cheaper and less complicated completions, possibly avoiding redundant capital expenditure (capex) in the completion phase. Given the important role of well intervention it is essential for oil companies to focus on effective intervention work with minimum trouble time and efficient uptime.

Since 2007, Light Well Intervention (LWI) vessels have finally started to gain ground as specialised vessels for subsea intervention. After numerous years as a concept, LWI has proven its viability following several successful subsea interventions in the North Sea. The daily rate of a LWI vessel is between half and a third of the cost of a conventional rig. If subsea interventions can be made cheaper by increasing operational efficiency, operators will be able to perform a larger number of interventions per year. The LWI step change can make this a reality.

BP aspires to make more and more use of LWI vessels to reduce the use of expensive rigs. These vessels will be used on most of the wells in the North Sea during the next years and it is necessary to prepare BP Norway for this subsea transition. Another benefit of contracting LWI vessels is freeing up rigs to focus on drilling, completion and heavier workover projects. A drilling rig can perform all work on wells, but due to future development aspirations and cost saving the focus in this thesis will be on the light well intervention alternative, although all other alternatives will be mentioned.

The BP story began in 1909 when it was founded as the Anglo-Persian Oil Company. The company got its first taste of deep water when Shell sold a 28.5% share of their Mars prospect in the Gulf of Mexico (GoM) in 1988 and became one of the largest offshore players on the globe after the acquisition of Amoco. Prior to this, BP had gained offshore experience while developing its first subsea field in shallower waters in the hostile North Sea (1981). The 5-well Buchan was tied back to a floating rig and deemed successful. Several developments followed through the 80's and 90's including Seillean, Magnus, Don, Andrew, Machar, Foinaven and Scheihallion fields [1].

In 2007 BP realised it was not doing enough to develop its subsea well stock. It was estimated that the value of 1% increase in Recovery Factor (RF) from the area West of Shetland alone would represent 30 million barrels of oil. This led management to enhance focus on improved delivery from the current assets in the North Sea.

West of Shetland the weather conditions are horrendous. This means that any intervention work has to take place during summer months (present policy), and BP has estimated this window to 90 days per year. This means that access to appropriate vessels in this period is essential. Everyone wants to do subsea work during the summer and consequently the vessel rates peak during the summer season. Efficient year-round capability could improve economics further.

Today BP has over 275 subsea wells all over the world and rivals Statoil as the most experienced subsea well operator. BP is not just any other major oil company in this respect being the most experienced LWI subsea intervention company on a global scale chastised only by Statoil. The amount of data BP has is overwhelming. With this backdrop the study of lessons learnt and experience becomes even more relevant.

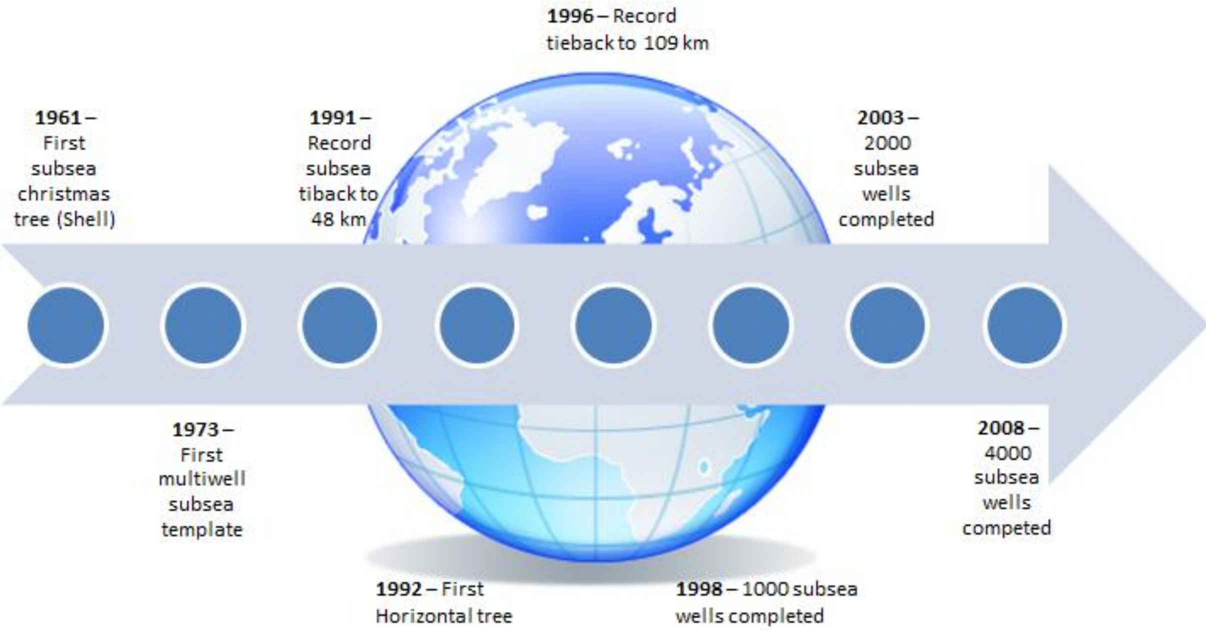


Figure 1: Historical development of subsea wells in the world [2].

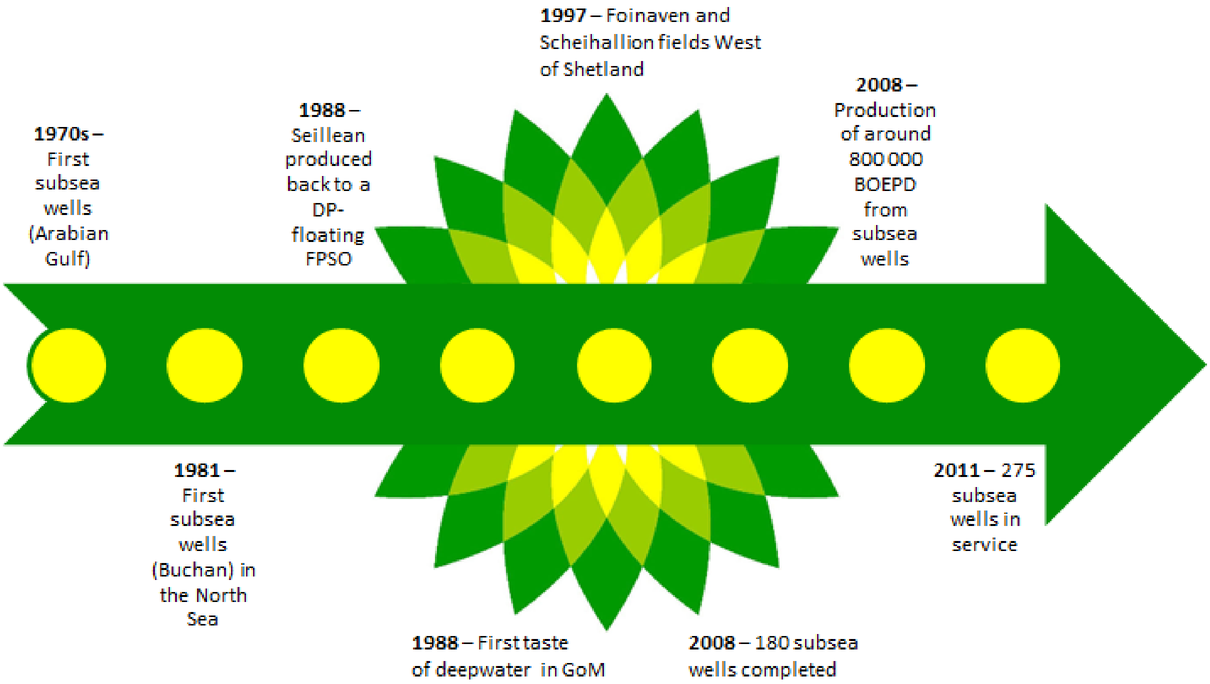


Figure 2: Historical development of subsea wells in BP [1].

1.1 Why write this thesis?

The intention of this thesis is to make it possible for BP to increase their operational subsea well intervention efficiency by active organisational learning (using previous BP operations as basis) and by practicing a proactive risk mitigation approach. The thesis is intended to prepare BP Norway for soon-to-come subsea well interventions, but since all operational data and lessons learnt are provided by BP UK, the results may very well be of assistance for BP UK campaigns and future reference for anyone undertaking LWI operations as well.

Or in short: To improve efficiency and value creation for BP Norway's Future Subsea Light Well Intervention Operations.

The overall breakdown structure and improvement connections of the thesis are illustrated below. For clarification it is noted that the bottom arrow is meant to illustrate that the whole thesis work will contribute to achieve the final objectives.

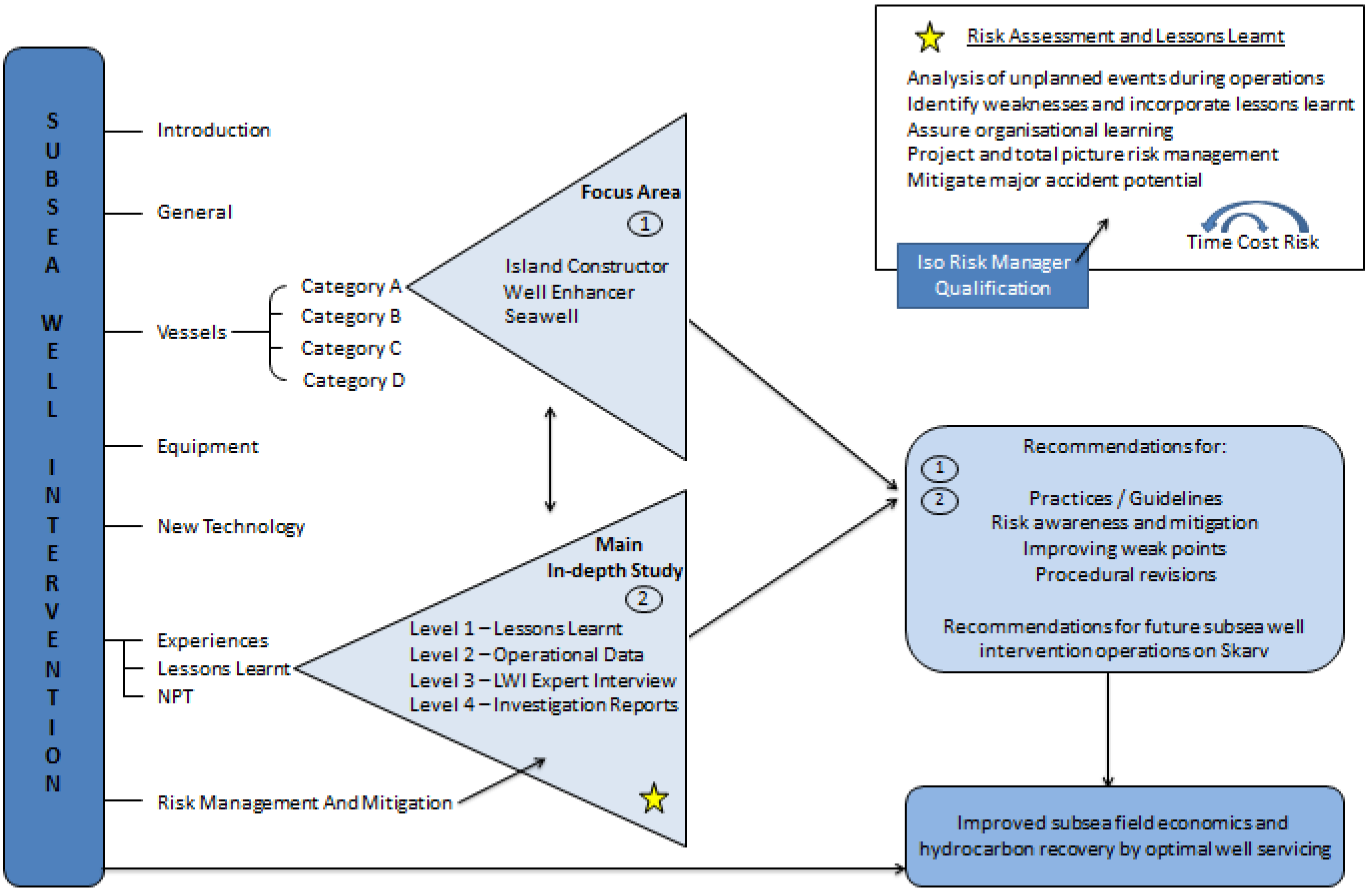


Figure 3: Basic breakdown of thesis structure.

1.2 Plan for workflow

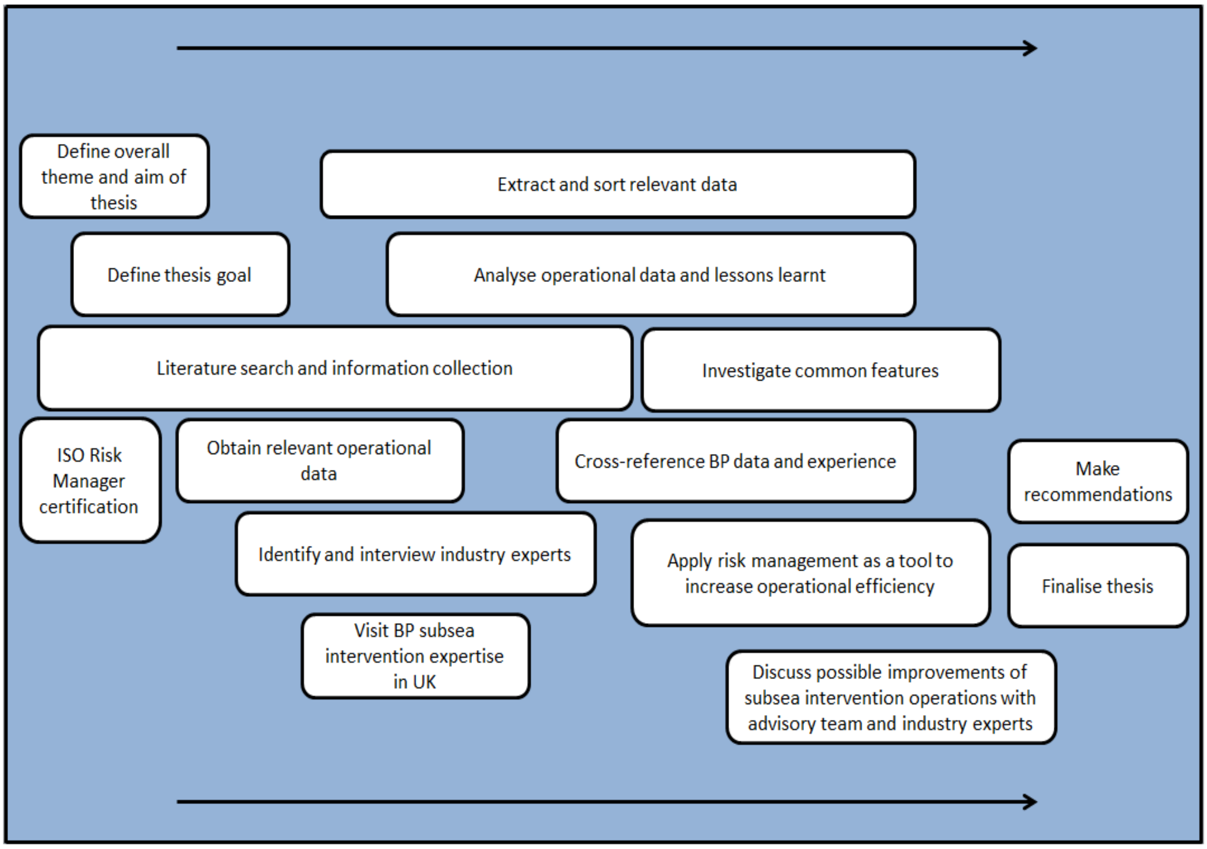


Figure 4: Progression plan.

A complete detailed plan can be found in appendix A.

2.0 Subsea Well Intervention Definition

Subsea well intervention is describing the activities around going onto and into subsea wells with the intention of maintenance, well evaluation, value generation, repair, plug setting or performing pumping operations. Well intervention does not normally cover the ability to perform full drilling operations or workovers with pulling of completions and installing new ones.

The subsea well intervention scheme for a year is normally decided by assessing all possible intervention candidates, their integrity status and production history. Are there wells that cannot be left as they are? An expert team rigorously reviews the wells suggested for intervention along with rig and vessel schedules to determine the potential value creation impact for each well. From this a complete plan for the year is made to streamline the projects and fit them into available slots.

2.1 Skarv Field Development

Figure 5: Skarv Field Location [3]

The Skarv field was discovered in 1998 and is located in the Norwegian Sea about 200 km West of Sandnessjøen, between the Statoil operated Norne field (35 km to the North) and Heidrun field (45 km to the South). It is located in water depths of 350 to 450 m with its focal point, the Floating Production Storage and Offloading (FPSO) vessel, located at a water depth of about 368 m. The Skarv field development comprises the Skarv and Idun fields which are located in blocks 6507/5, 6507/6 and part of block 6507/2 and 6507/3 [3]. The development is operated by BP which has a 24 % interest. Statoil is the biggest owner (34 %) while Shell (28 %) and ExxonMobil (14 %) also have a piece of the pie.

The Skarv project is currently one of BP Norway's largest projects with production start now expected in Q4 2012 (one year delayed). The reservoir development plan includes 17 wells. 13 producers (7 of which oil producers) and 4 gas injectors. These wells will be drilled from 5 templates placed in three drilling centers (Idun, Skarv A / Tilje and Skarv B/C) as can be seen in the development outline below. The production strategy is to produce oil and gas simultaneously from the Skarv and Idun fields as they share a common aquifer. The oil will be produced using pressure support from gas injection to maximise oil recovery and the horizontal oil production wells will be kept on stream for as long as they continue to produce. Once gas injection is stopped, the gas injectors and oil producers will be used to back-produce the gas caps.

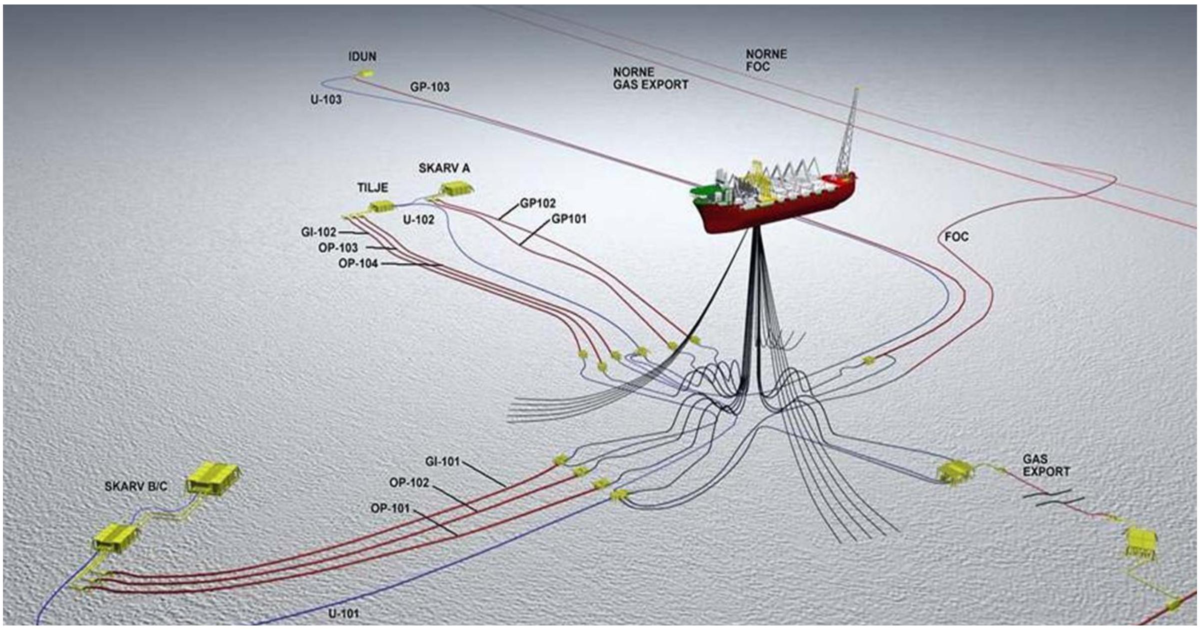


Figure 6: Skarv Field Development Overview [4].
U = Umbilical, GI/GP = Gas Injector/Producer, OP = Oil Producer, FOC = Fibre Optic Cable

3.0 Subsea Well Interventions

Subsea developments are usually tied back to a fixed platform and infrastructure or built as standalone structures i.e. with a FPSO facility handling production either by using tankers to shuttle the hydrocarbons to refineries or by exporting it through pipelines. Standalone installations are usual for remote developments, too far away from existing infrastructure, while some subsea wells produce directly to onshore facilities (Snøhvit). Subsea wells are drilled by Mobile Offshore Drilling Units (MODUs) which can be dynamically positioned or anchored to the seabed (mooring usually only used by semi-submersible, mono-hull drilling units and FPSOs) or jacked-up above the wells. When the wellbore has been completed, these MODUs usually move on to their next location to drill new wells. As the cost of drilling units is very high this provides a need for smaller vessels to do lighter well work and subsea intervention operations.

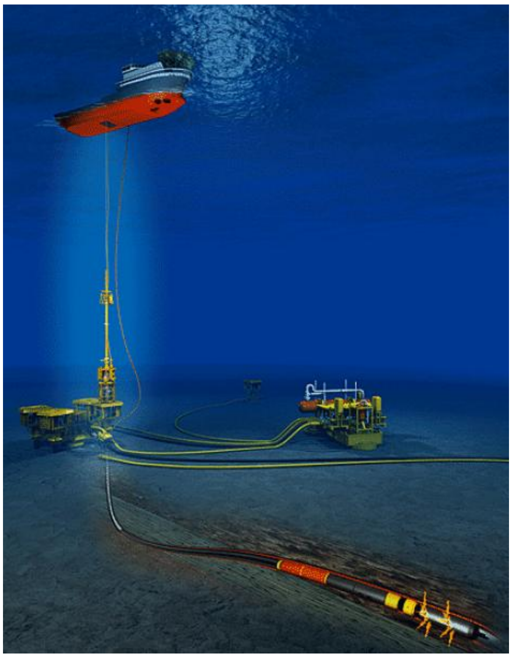
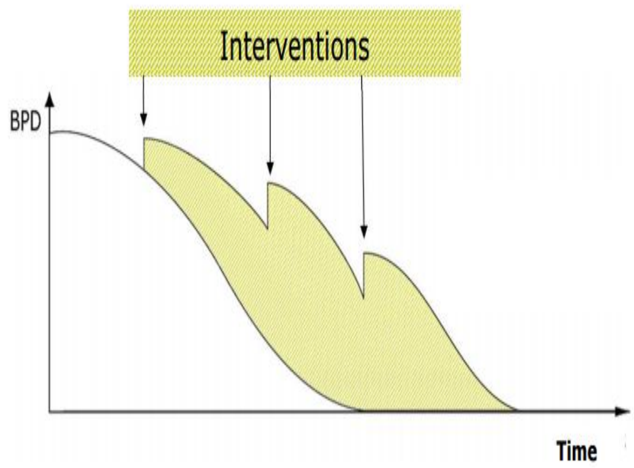


Figure 7: Logging operation from a LWI vessel [5]

As mentioned, the main motivation for well intervention is increased hydrocarbon (HC) production and recovery or handling of integrity related problems (such as missing or questionable well barriers). When time passes, water cut increase, the gas-oil ratio (GOR) rises and corrosion, scaling and mechanical problems occurs. Many producing wells are a lot older than they were originally designed for, so there are many "skeletons in the closet" even on the NCS. The life of these wells has been extended partly due to new improved oil recovery (IOR) technology making it possible to extract bigger volumes of HC than was imagined during the initial design phase. In some cases, well integrity is becoming questionable, and several close calls on the NCS have led authorities to tighten the follow up on barrier health and requirements. Operators on the NCS have to keep and provide integrity status of all wells at all times. Solid well integrity (barriers need to be intact and operational) is crucial and will be covered in a later chapter.

There are currently three main intervention techniques available to intervene on subsea trees. These are applying rigs, riser systems from various vessels or the riserless wire through water technology. This thesis will focus on the third option - Riserless Light Well Intervention (RLWI). Some other new technology for possible future use will also be mentioned.

There are many reasons and drivers to intervene in a well. Intervention operations can for instance investigate unexpected performance, diagnose the well or re-instate barriers. A complete overview will be provided in a following section but whatever the purpose of an intervention, periodical and ad hoc intervention is by itself the biggest contributor to maintaining high production. Some (such as supporters of intelligent completions) might claim that intervention has a short-lived or limited effect on wells, and it is a statement that occasionally will be accurate. Intervention work is often underappreciated due to its apparent simplicity (compared to drilling and completion operations), price-tag and sometimes limited long term effect in relation to how much value is in fact added by this group. However, most well interventions have a relatively short pay-back time and excellent economics. Cost-benefit and net present value calculations are performed to establish economics of intervention work. Today, BP's North Sea subsea wells are responsible for more than 30% of the company's total production in the region, emphasising the importance of keeping these wells flowing.



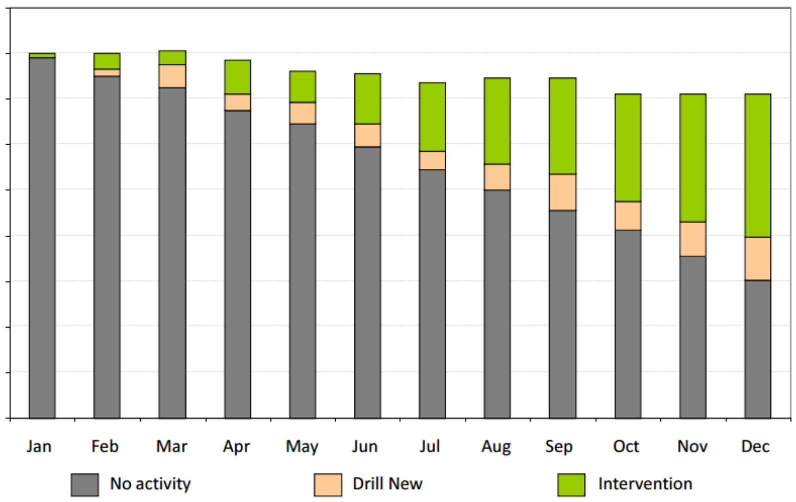


Figure 8: Graphs clearly illustrating value creation and increase in ultimate recovery factor by intervention [6].

3.1 Well Integrity

Well integrity is defined in the NORSOK (NORsk Sokkels Konkurranseposisjon) D-010 standard [7] as "application of technical, operational and organisational solutions to reduce risk of uncontrolled release of formation fluids throughout the life cycle of a well."

Continuous well integrity is the most important criteria in any intervention operation, and often the need for intervention is integrity related in itself. Pressure control equipment for the different phases - i.e. integrity during rig up, entry, operation and exit needs to be in place and dynamic barrier envelopes need to be under control at all times.

A well-known integrity challenge is sustained casing pressure (SCP). This is often caused by leaks, and the leaks are normally caused by erosion (mechanical process) and corrosion (chemical process). Video and acoustic tools can help discover leaks. Integrity related interventions may also consist of repair and inspection of wells and subsea hardware such as trees, manifolds and pipelines. The caliper tool is one of the main integrity indicators for integrity diagnostics purposes.

Well integrity requirements are covered by NORSOK D-010 "Well Integrity in Drilling and Well Operations", with integrity and pressure envelopes playing a central role in this standard. These envelopes usually consist of two independent well barriers, and are often portrayed in well barrier schematics. Integrity priority is a given due to company safety requirements and government restrictions. The operators are responsible of handling all leaks or serious integrity issues immediately.

3.2 Subsea Well Intervention Requirements

Hydrocarbon exploitation can be a risky business and the potential for disasters is ever present. Huge material damage, negative environmental impact or in the worst case loss of lives can and has been the result of careless risk and quality management in the oil industry. Due to the potential consequences related to this type of activity, there is naturally a wide range of rules, requirements and regulations that needs to be adhered to. These can be divided into four principal areas:

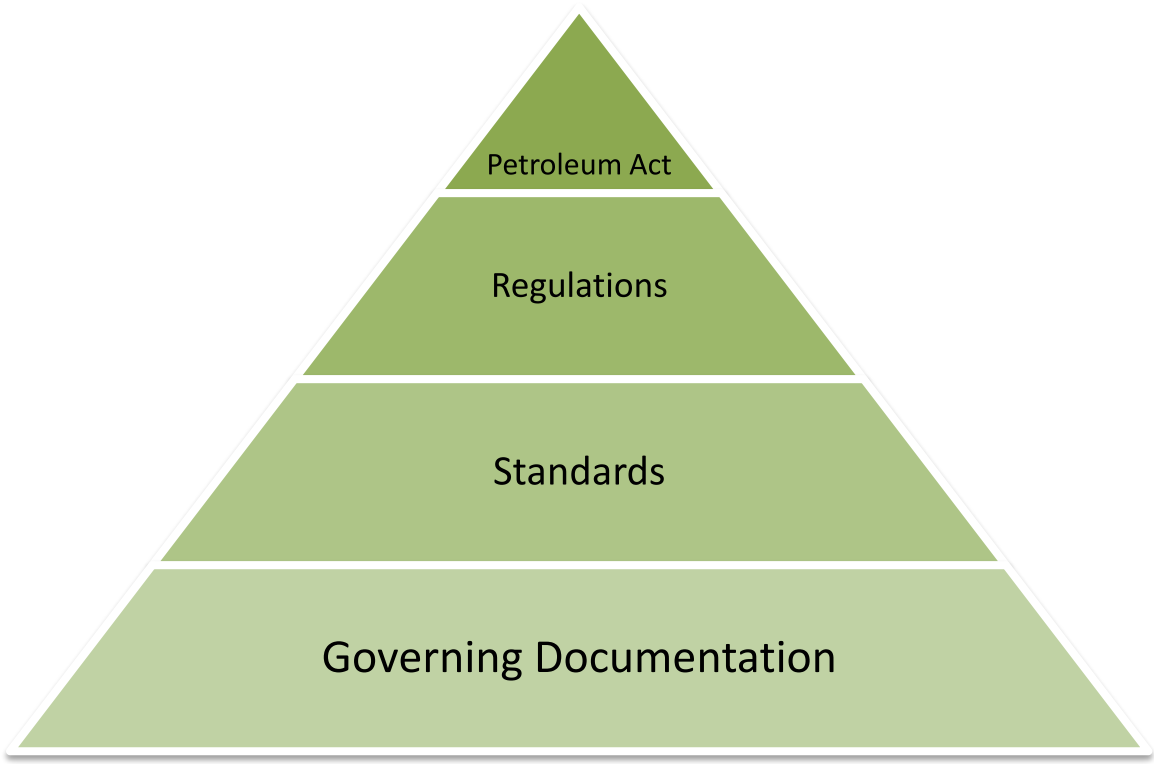


Figure 9: Requirement Pyramid

3.2.1 Petroleum Act

The “Petroleum Act” (petroleumsloven) is the ultimate legal document that must be followed by everyone operating on the NCS. This category includes the statutory requirements imposed by the Norwegian Petroleum Directorate (NPD), Oil and Energy Department, Police or the European Union (EU requirements). If an operator does not comply with these rules and regulations, legal action could result in consequences such as fines, loss of license to operate or with responsible individuals sentenced to jail time.

The 1st of January 2004 the Petroleum Safety Authority (PSA)(Petroleumstilsynet, Ptil) was formed as an independent governmental health, safety and environment (HSE) regulator [8]. The PSA is subordinate to the Ministry of Labour and is the regulator for technical and operational safety, including emergency preparedness and for the working environment in all phases of the petroleum activity. This includes planning, design, construction, use and possible later removal. Before 2004 the NPD had this responsibility as part of its total offshore authority.

The Skarv FPSO is operating under two regulatory regimes; The Maritime Directorate (Sjøfartsdirektoratet) and the Petroleum Safety Authority. This is also true for LWI vessels and thus requires good coordination, particularly with respect to risk analysis and emergency preparedness. It is mandatory for any vessel performing well intervention activities on the NCS to have an Acknowledgement of Compliance (AoC, SamsvarsUTtalelse (SUT)). This expresses the authorities' confidence that petroleum activities can be carried out using the facility within the framework of the regulations [9].

According to the international Maritime Organisation (IMO), the shipping company (vessel owner) and each ship are responsible to comply with the International Ship and Port Facility Security Code (ISPS Code). The Maritime Directorate performs inspections and audits to ensure this is adhered to and overall compliance with the Norwegian maritime legislation.

3.2.2 Regulations

There are many regulations that are normative for well intervention and subsea operations on the NCS and have been made to ensure compliance with the petroleum act. These regulations include but are not limited to:

- Framework HSE
- Management
- Technical and Operational
- Facilities
- Activities

There is a wide range of more specific regulations such as for personal protection equipment (PPE) or electrical equipment. All of the regulations that operators have to be in compliance with can be found on the PSA and NPD websites.

Most of the conditions stated in regulations by the PSA refer to NORSOK standards.

3.2.3 Standards

The guidelines to the regulations often refer to recognised standards as a way to fulfill the functional requirements in the regulations. The PSA regulations refer to, among others, the following standards:

- The Norwegian Standards Association (EN (European Standard)-, NS (Norwegian Standard)-, ISO (International Organisation for Standardisation)- and IEC (International Electrotechnical Commission)-standards)
- NORSOK
- Det norske Veritas (DnV)
- The Norwegian Oil Industry Association (OLF)
- American Petroleum Institute (API)
- International Maritime Organisation (IMO)
- American Gas Association (AGA)

There are several regulations and guidelines to take into account prior to performing any intervention operation. The NORSOK standards are the Norwegian oil industry's own standards and not authority documents as such. The NORSOK standards are defining requirements that help companies to operate safely and hopefully cost effective. These standards may be omitted if an equally good or better compliance solution is proposed by the operator. If the BP standard creates a higher obligation than NORSOK, it shall be followed (in Norway) as long as this also achieves full compliance with the NORSOK standard.

The NORSOK standards are one of the strictest standards in the world, and the BP standards are basically the NORSOK standards elaborated and specified. NORSOK D-010 specifies necessary barriers. The NORSOK D-010 standard is again based on recognised international standards from ISO, API, ASTM (American Society for Testing and Materials) and OLF guidelines. These are meant to cover the broad need for the oil industry operating on the NCS [10]. Revision 4 is underway and will probably be published the 1st of May 2013 [11], 10 months delayed.

Other standards worth mentioning are the ISO 14001 (Environmental management system) and EMAS (Eco-Management and Audit Scheme) which were publicised by EU in 1993 and audited in 1995. These standards are voluntarily for establishing systems for environmental registration and improvement.

North Sea Region requirements include but are not limited to:

- D-002 Describes the design, installation, requirements for well intervention equipment and their systems.

- API 6A – Specification for Wellhead and X-mas tree equipment

- NS5814 – Establishes recommended requirements to risk management of operations

- D-010 – Well integrity in drilling and well operations
- API 14A – Specification for subsurface safety valve equipment
- API RP 14B – Design, Installation, Repair and Operation of Subsurface

3.2.4 Governing Documentation

All operator companies have their own governing documentation that has to be adhered to. There are several governing documents that need to be adhered to when operating on behalf of the BP organisation. These include but are not limited to:

- BP Group requirements
- BP Norway Governing documents

There are also many company practices and procedures. These include but are not limited to:

- Well Intervention Operation Practices
- Drilling and Well Operations Practices (DWOP)
- Well Intervention Operation Guidelines (WIOG, includes subsea guidelines)
- Group practices (Scope of the group practice is to provide company requirements, unity on a global scale and recommendations to ensure safe operations.

The most commonly used Group Practices (GP) in the BP Norway well intervention department are:

- GP 10-10 – "Well Control"
- GP 10-35 – "Well Operations"
- GP 10-36 – "Breaking Containment"
- GP 10-45 – "Working with Pressure"
- GP 10-60 – "Zonal Isolation Requirements"
- GP 10-65 – "Rig Positioning"
- GDP 3.1-001: Assessment, prioritisation and management of risk

Intervention responsibilities are always clearly communicated in pre-operation meetings and in BP guidelines. The process is extremely important and an auditable trail has to be chosen when taking over responsibility for wells in operation, and similarly when handing maintained wells back to production. Acceptance criteria are technical and operational requirements that must be fulfilled and documented to qualify.

When changing a programme or procedure, a Management of Change (MoC) is required. One of the important drivers for major accidents is change, so one of the most important aspects of any change is the good risk management surrounding it.

MOC Number	Reason For MOC
WOUK/MOC/11070/ June2010/001	Tubing pressure for punch run
WOUK/MOC/11070/ June2010/002	Well Entry & Well Exit Tests
WOUK/MOC/11070/ June2010/004	Change Well Exit Procedure
WOUK/MOC/11070/ June2010/005	Additional Tool string
WOUK/MOC/11070/ June 2010/021	Drift Annulus and Set Annulus Plug & Prong PN01 & PN04

Table 1: MoC examples from the 2010 Don/Magnus Campaign [12]

3.3 Vessel Alternatives

There are several alternatives and manufacturers of well work and drilling vessels and the vessels come in a wide range of different sizes, specifications and capabilities. The current rig market on the NCS is characterised by limited supply with increasing rig and vessel rates translating into a need of using available capacity in an optimal way.

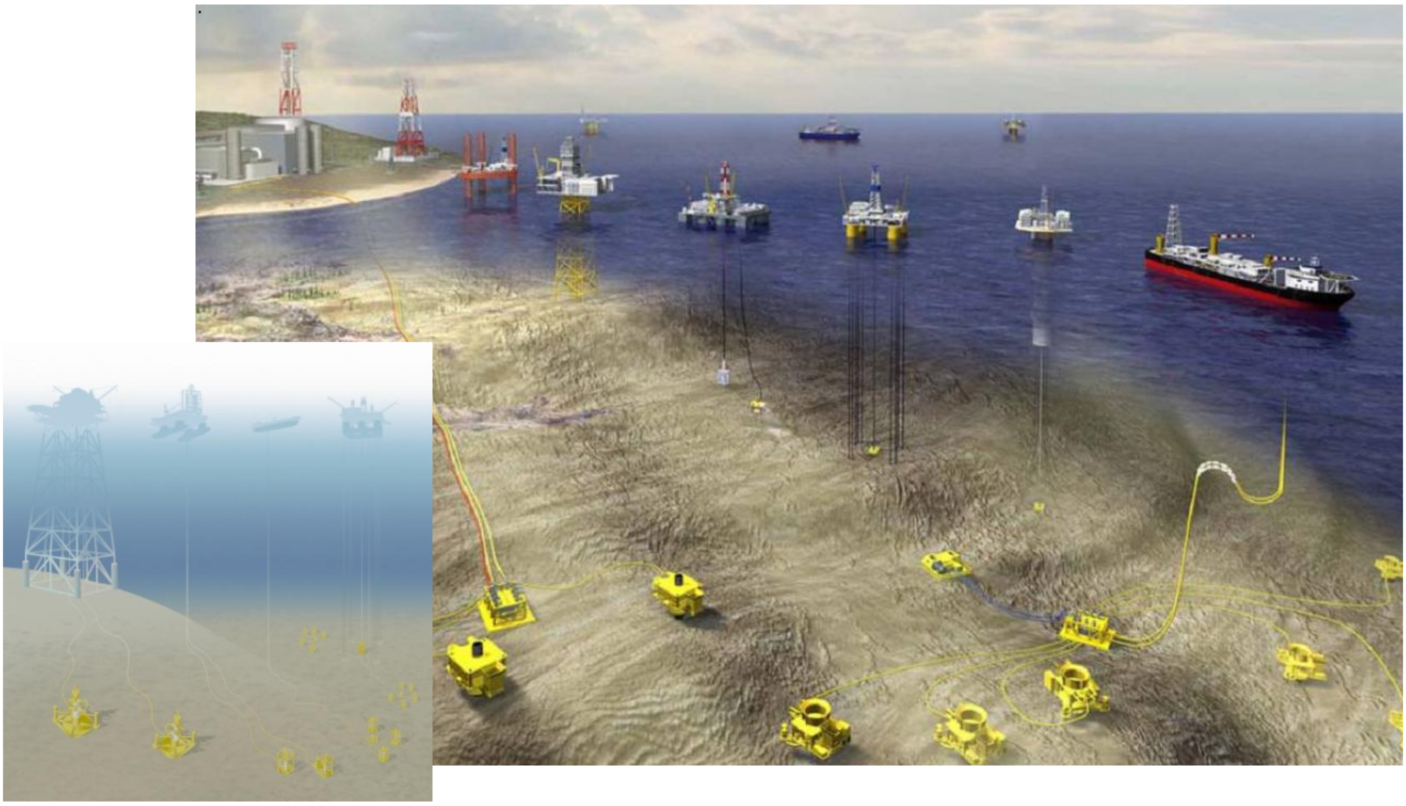


Figure 10: The subsea and surface support landscape [2, 13]

It has become common practice in the industry to describe different rigs and vessels in categories to immediately know the normal work scope and capability of the vessel in question. Which category (CAT) is chosen for intervention work depends primarily on the ability to execute the operation safely and the probability of getting the work done. A combination of categories is often used; LWI to prepare and finalise while rigs come in to do the heavy well work. Category selection depends secondarily on economy, risk and availability.

There is no universal, international or standardised categorisation system, so different companies may have made their own specific categorisation criteria. In theory this means that CAT A for BP, might be different from CAT A in Statoil. In practice categories A, B and C normally have common demarcations and are used similarly between oil companies. This is not true for BP that operates with a different vessel type categorisation. CAT A and B are the same as in the table below but C is heavy intervention while CAT D is for drilling [14]. Statoil is currently developing a new type of production drilling rig they have called category D.

In this thesis the four main categories of intervention vessels are defined as:

Category A	Light vessel able to perform mostly wireline operations, subsea inspection and repairs.
Category B	Vessel able to perform workover (pulling and running tubing) and riser operations with coiled tubing (CT) ability.
Category C	Conventional drilling rigs capable of performing all well operations through marine riser and BOP. Heavy intervention capability.
Category D	Production Drilling, with focus on completion and intervention needs.

Table 2: Vessel Category Definitions

It is mentioned that Statoil also operates with a Category J: Jack Up Rigs specially designed to operate in 70-150m water depth, normally with BOP on surface and high-pressure riser to seabed systems. Category J will not be further addressed in this thesis.

More conventional supply vessels may also be modified to perform simple well surveillance and intervention capabilities like ROV inspections, subsea module change-outs, pumping and valve operations.

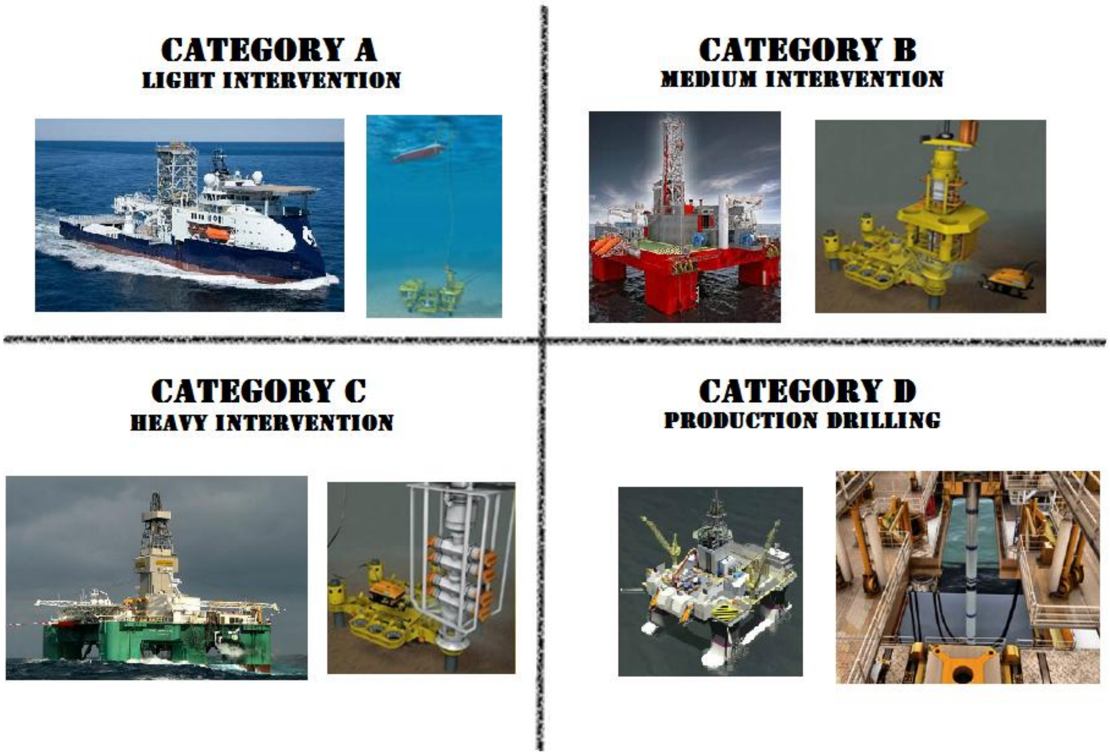


Figure 11: Rig and vessel categories [15-20]

3.3.1 Category A – Light Vessels

Category A is often called Light Well Intervention (LWI) and is the category that demands least resources and personnel of the four. There are many variations of category A vessels and they can have different lay-out, equipment and specialisation. Because of its lower cost, this is the solution operators want to use to perform as many well intervention operations as possible. Statoil has two vessels working year-round (Island Wellserver and Island Frontier) on the NCS. They have recently also contracted Island Constructor for well work from 2012 and onwards.

Today LWI is mostly used for wireline operations with the "Wire Through Water" (WTW) approach via a subsea stack (lubricator package) which is lowered down and latched on to the XMT, an operation also called Riserless Light Well Intervention [21]. Coiled tubing is not yet possible to perform from LWI vessels unless a riser is connected. Shell has applied a successful CT operation from the Seawell LWI vessel, to prove that it is possible. This operation type has not caught on yet in the industry and many technical, operational and safety issues remain, so in this thesis LWI is associated with the RLWI technology.

Remotely Operated Vehicles (ROVs) are crucial to manage and secure access to the wells. They attach the guide wires on the wellhead frame and running tools are connected to these wires. LWI vessels have to be approved by the Norwegian Petroleum Safety Authority before they can operate on the NCS. As for normal drilling rigs, the LWI vessels require a compliance statement (AoC) from the PSA as mentioned earlier in order to be approved for well related operations on the NCS.

The biggest drawback for Category A vessels in relation to their capabilities is weather vulnerability. The North Sea hosts a harsh environment and vessel limitations prohibits operation large fractions of the year. Work West of Shetland i.e. has to be planned for summer months with the LWI vessels completely absent during winter months. 8.7 % of the downtime (mean for 2009-2011) has been due to wait on weather [section 4.6], even under the summertime only philosophy. When weather is bad, helicopters might not be able to land on the vessel and the vessel may have to transit to shore for crew changes stretching operational downtime further. The relevant limitations of the LWI vessels include heave, weather, Personnel On Board (POB), fluids capacity, logistics, crane capacity, Hydraulic Horsepower (HHP) and station keeping. There are also weight and lifting limitations to take into account, particularly when landing equipment on subsea wellheads. Other LWI limitations are:

- No marine riser hence no circulation path (except small diameter hose)
- Pull strength, unable to pull completion tubing or casing strings (unless cut into short (10 meter) segments)
- Limited to wireline, and simple repairs. Potentially coiled tubing but is not yet a proven standard.
- No/limited/minimum rotation capabilities
- No subsea dedicated BOP for overall well control, only intervention controls (well control package)

A floating body at sea (such as a LWI vessel) has six degrees of freedom [13]:

1. Heave - Moving up and down
2. Sway – Moving port and starboard
3. Surge – Moving forward and aft
4. Pitch – Tilting forward and backward
5. Yaw – Turning left and right
6. Roll – Tilting side to side

To sum up this is a lot of movement freedom well engineers do not like!

The station keeping Dynamic Positioning (DP) system controls only three degrees of freedom (horizontal plane), surge, sway and yaw. Vessel control includes thrusters control, anchor system (not common for CAT A vessels), bilge and ballast control, fire and gas system, emergency shutdown and communication.

The CAT A vessels can typically perform any job performed on wireline (WL):

- Pull and set plugs
- Well monitoring, Run wireline (logs)
- Make well diagnosis
- Perforating/re-perforating
- Subsea equipment repair
- XMT exchange

3.3.2 Category B – "The well intervention machine"

This category fills the gap between light and heavy intervention, and is less limited by weather whilst cheaper and more specific than a conventional rig. CAT B emerged after realising the need for maintenance on damaged and underperforming wells to be able to increase ultimate subsea well recovery rates. CAT B is therefore also called the "Increased Oil Recovery Machine". It is made for mid-water operations and is capable of operating across the entire NCS.

Currently there is no alternative service presently able to perform coiled tubing operations and through tubing rotary drilling (TTRD) efficiently in subsea wells. Fit for purpose intervention equipment such as CT, TTRD stack and WL is integrated in the CAT B rig. Lessons from CAT A and C have also led to CAT B implementing a skidding system to minimise number of lifts and diminish related risk in rough weather.

Statoil awarded Aker Solutions with a contract for Category B intervention specific rig in April 2012. Their reasoning strategy is based on tailor-made rigs and vessels for different operations to achieve sustainable cost levels. The rig can perform all traditional intervention operations, including workovers and trough tubing drilling and is expected to reduce the operational cost of well intervention up to 45% [22]. Statoil operated fields have reached more than 50% recovery which is considerable in international comparison. The rig is scheduled for service in 2015.

The "medium" intervention category term often refers to operations with a riser between seabed and surface, a high pressure riser is established between the subsea X-mas tree and vessel cellar deck [21].

CAT B offers extensive maintenance capability. In addition to CT and TTRD, the rig performs wireline, well testing, ROV- and pumping services (cementing). It will be very interesting to observe operational data versus CAT B objectives and expectations when the rig comes into action.

3.3.3 Category C – "Old fashioned" drilling rigs

This category basically consists of conventional drilling rigs capable of any drilling and well operation including heavy intervention such as workovers. It has a subsea BOP with a low-pressure riser.

The drilling rigs are made for different applications such as deep water, ultra deep water or arctic environments. Floaters are used in water depths above 150 m; below this the jack up often represents a more cost efficient solution.

The category also includes drillships. For this thesis the normal CAT C will not be assessed further. They can basically do anything we want, but are expensive and often represent capacity overkill in relation to well intervention needs. If a Category A vessel leaves the well in worse condition instead of fixing the problem, the CAT C rigs will be deployed to repair the damage.

3.3.4 Category D – An area dedicated workhorse rig

Category D is a brand new category initiated by Statoil in 2011.

While CAT B is tailor-made for intervention work, CAT D is tailor-made for production drilling with focus on completion and intervention needs within certain water and well depth limitations. The focus is reflected in all the deck space available for such operations. Safety in offshore logistics is another keyword for this category.

Statoil issued a desire of a tailor-made rig made for drilling the mature fields in mid-water (100-500m) at the NCS [19]. The motivation for this was the belief that the age of major elephant discoveries was over (something which has already been disproved by the Johan Sverdrup field) and the need to focus on smaller reservoirs with less hydrocarbons. Ensuring modern rig capacity in itself is also an important motivation. Common business logic denotes that less pay warrants less investments, hence the cost needs to be reduced for marginal fields to become commercially attractive. This led to the concept of category D rigs, and specifically to a rig made for production drilling (as opposed to exploration drilling) in cold climatic, mid-water range on marginal and mature fields on the NCS. It will be used for infill drilling, completion, heavy intervention, and be part of the aggressive approach to drill as many wells as needed to increase ultimate reservoir recovery. With many wells planned, a specialised MODU will save money. Statoil also hopes that their CAT D Rig can perform 20% more efficient production drilling and completion activities on the existing mature fields compared with the present rig fleet. This is an expectation that will be interesting to measure against real performance when entering into operations. In order to establish an excellent production drilling concept for the NCS, the following has been added to CAT D [18]:

- Large available deck areas and increased crane coverage for completion/intervention logistic.
- Excellent motion characteristics,- reducing unproductive time related to Waiting on Weather.
- “1.5” Derrick, - simultaneous drilling and building stands.
- Moonpool trip saver, - hanging off BOP and Riser in the moonpool while running XMT.
- Separate Completion and Drilling fluid system, - converting directly from drilling fluid to completion fluid mode without having to clean up the system.
- Offline service deck flush with drill floor, - enabling all completion and intervention equipment interface with drill floor to be handled off critical line (operational time line).
- BOP, riser tension and compensation systems designed for existing well head templates with focus on well head fatigue life (less loading than 5th and 6th generation rigs).
- High level of redundancy with respect to material handling, crane coverage and pipe handling to drill floor.

Other motivation for the new specialised rigs is the fact that the present rig fleet is aging. Statoil has developed CAT D specifically for the NCS with a drilling depth capability of 8500 m and a water depth limitation of 1300 m. As it is a semi-submersible rig, it can easily be converted to operate in deep water, High Pressure High Temperature (HPHT) and arctic regions, adding to fleet flexibility.

For this thesis the CAT D will not be assessed further. The workhorse rig can basically do anything (as described above) but are expensive and as CAT C often represent capacity overkill.

3.4 BP Light Well Intervention Vessels

BP has made use of three light well intervention vessels in the North Sea. These have been operated by BP UK performing work in the North Sea on the UK Continental Shelf and West of the Shetland Islands. The three vessels are “Island Constructor”, “Well Enhancer” and “Seawell”. Although they are all with the same broad category A, their capabilities and specialisation vary from vessel to vessel. A complete outline of the three BP vessels is provided below.

3.4.1 Island Constructor

Figure 12: The Island Constructor [23]

Island Constructor was built for the marine company Island Offshore by Ulstein Verft AS and delivered in 2008. BP has chartered the purpose built multifunctional LWI vessel for 90 days a year until 2013, and it is the only LWI vessel in BP North Sea’s portfolio that can be used to operate in the water depths West of Shetland on the Clair, Foinaven, Loyal and Schiehallion fields. The vessel is presently capable of performing the following operations:

- RLWI with subsea lubricator system (described in a later chapter)
- Subsea construction and equipment installation
- Subsea inspection, repair and maintenance
- General ROV services

For a single operation there are normally several specialist suppliers: Oceaneering provides ROV support, FMC Technologies provide the subsea intervention package and Aker Q-serv provides wireline service. In addition there will always be even more specialised sub-contractors for tools and special operations.

Regarding technical aspects [24] the first obvious difference between the Island Constructor and other conventional LWI vessels is its Ulstein famous “X-bow” design, claimed (by Ulstein) to reduce drag and increase stability. It has a fully redundant dynamic positioning system and is certified to DP Class 3, the highest and most reliable station keeping capability available. There are two azimuth thrusters at the aft, two tunnel thrusters in the forward part and two retractable azimuth thrusters (one at each end). It has its Module Handling Tower (MHT) or “derrick” centered above the 8x8 m moon pool. The MHT is rated for a maximum of 300 t SWL (Safe Working Load), while the main winch is rated for 100 t Active Heave Compensated (AHC) and can operate to water depth of up to 1100 m. In addition to active heave compensation, the MHT can offer constant load tension lifting. The operational work is concentrated around the MHT since all equipment is lowered down the moon pool. Apart from the main winch we can find a work basket, cherry picker (boom lift) and 4 guide wire winches in the MHT. The guide wires are used for subsea alignment purposes. A skidding system is used on deck to assure safe handling of heavy equipment and driven by two hydraulic skid units. There is one main skid leading into the moon pool, and several “side-skids” to park pallets. The cranes are as a general rule never used at sea as long as it is avoidable.

The derrick control room is overlooking the moon pool area and has three operational chairs in charge of:

1. Work Over Control System (WOCS), which controls all pressure control equipment
2. Derrick Control, which controls the main winch and guide wires
3. Remotely controlled wireline services

In addition there are two operations offices, one overlooking the entire operation and one for logging, tractor and wireline personnel.

The vessel is capable of carrying 199 m^3 of methanol in 4 tanks. There are two kill pumps and appurtenant reels for the hoses and umbilical, stock tanks and mixing systems at the aft end.

3.4.2 Well Enhancer

The Well Enhancer is a state of the art well intervention and saturation diving support vessel. It was built by the Helix Energy Solutions Group at Merwede shipyard in Rotterdam for their subsidiary “Well Ops” [25]. The vessel was developed after analysing how the “Seawell”, its predecessor, coped with the North Sea environment. The new additions include SIL (Subsea Intervention Lubricator), skidding system, provision for future coiled tubing operations and communication redundancy to avoid downtime due to communication breakdown. The Well Enhancer has 1100m2 of main deck space facilitating logistics, and is capable of performing a broad range of well intervention work such as:

- Subsea construction and equipment installation
- Subsea inspection, repair and maintenance
- General ROV services
- Saturation diving activities

Figure 13: The Well Enhancer [26]

The Well Enhancer came into service in 2009, and is along with Island Constructor significantly more modern than the Seawell. The two have different focus areas though; while Island Constructor can operate at 1100 m of water depth [27], the Well Enhancer has focused on dive operations with a dive bell rated to 300 m. The ship has a capability of having 18 divers in saturation, sufficient for continuous diving capability. This along with the ROVs provides full inspection, repair and maintenance ability including subsea tie-back, spool installation and diver habitat operations [28]. The Well Enhancer has many of the same features as the Island constructor, but can only operate down to a maximum of 600 m of water depth and is more focused on subsea equipment work capability than any well related work.

3.4.3 Seawell

The Seawell pioneered the subsea well intervention market and has been operating as a LWI vessel since 1987. During its 25 year history, the vessel has entered more than 650 wells, decommissioning over 150 live and suspended wells and 15 subsea fields – a track record second to none in the North Sea. It is a custom designed, dynamically positioned (DP2 class) LWI and saturation diving vessel.

Figure 14: The Seawell [29]

The vessel features a 7 x 5 m moonpool and a travelling block rated to 80 t capacity. The derrick is equipped with guide line tensioners, a subsea wireline lubricator winch, riser handling capability and associated equipment. The twin main cranes are a special feature and can provide a combined load capacity of 130 t [30].

Seawell can accommodate 18 divers in saturation, and common practice during operations has been to keep 6 divers in saturation to assist if necessary. Divers are on a shift pattern and each Supervisor runs "his" dive. Divers have been on the vessel for a number of years so they are familiar with the well operations and equipment used. A ROV monitors the divers at work and the diving system is rated to 300 m.

A well stimulation plant provides full chemical treatment capability, including acid wash. It is also capable of flowing wells back to the surface for clean-up operations and can also be adapted to perform well stimulation tasks (bullheading).

3.4.4 Vessel Comparison

A technical comparison is shown below.

Capacity	[Unit]	Island Constructor	Well Enhancer	Seawell
Operating depth	m	1100	600	400
Main deck space	m^2	1380	1100	900
Length	m	120,2	132	114
Gross tonnage	t	9100	9200	9158
Draft	m	7,00	6,25	7,30
Personnel		90	120	122
Diver capability		0	18	18
DP class		3	3	2
Moonpool area	m x m	8,10 x 8,10	7,02 x 7,32	7 x 5
Vessel speed	knots	15,3	13	14
Derrick lift capacity	t	300	150	80
Bulk fluid tanks	m^3	708	340	240

Table 3: Vessel Technical Comparison [24, 27, 30]

Vessel logistics limitations include [31]:

- Pump capacity
- Bulk capacity
- Mixing capacity
- Solids control equipment

There is no immediate correct answer as to which vessel is the best. The best vessel for the job depends entirely on the type and depth of the subsea well intervention. If diving capability is desirable, the Island Constructor cannot be chosen. The Skarv field lies between 350-450 m of water depth, which will rule out the Seawell for interventions planned deeper than 400 m. An evaluation as to which of these vessels will be appropriate for subsea well interventions on Skarv, will be part of the future recommendation scope later in this thesis.

3.5 Subsea operation and equipment

Accessing a well left on the bottom of the sea can be a challenging task. On the deck of a platform, rig-up and well access to a dry tree well (even though still time consuming) is routine with everything within eye-sight and hand-reach.

Monitoring and verification of subsea interfaces must be done continuously on anchored or DP vessels. Equipment design constraints and disconnect times in relation to vessel offset are important elements to consider. If tools are run in the well, the operational constraint imposed by the string must also be considered.

This section will focus on the conventional ways to rig up on a subsea well since this is most likely the procedure that will be used at Skarv based on BP experience in doing so. The method in itself is well known and proven and a typical subsea intervention normally stretches over 20-30 days.

Three lifts are required just to gain access to the well [32]. Two of the lifts are heavy lifts (loads over 5t), and require heavy lift procedures. The production from the well and any nearby wells (within a possible heavy lift drop zone) has to be shut down while the heavy lifts are taking place. The first lift is the tree debris cap. The second lift is lowering of the Well Control Package (WCP). Finally the Lubricator Section (with the Pressure Control Head (PCH)) is lowered onto the well.

When retrieving the tree cap to the vessel deck, the cap and all wireline toolstrings must be checked for Low Specific Activity (LSA) scale. LSA is a Naturally Occurring Radioactive Material (NORM) [33], and is most often found in process equipment. The LSA Scale is typically formed from the radioactive elements strontium and barium, which ends up being deposited as scale (sulphate) on the inside of pipework and production equipment but can also be found in safety valves or on the wellhead. Oil production mainly produces LSA scale composed of calcium carbonate or barium sulphate (barite). Calcium, barium and strontium are in themselves not radioactive, but radium (Ra) is co-precipitated with them, and the activity of the LSA scale depends on how much Ra is deposited [34]. The Ra content depends on rock type and its content of uranium and thorium. The salts are dissolved in the reservoir in a mixture of formation water and injected sea water. The deposition can also be initiated by formation water contact with drilling mud. The important mechanism is that the formation water chemistry is altered. This is brought to surface when the well starts producing. When pressure and temperature drops, the salts are deposited.

Scale in wells normally has to be removed mechanically but can sometimes be fought with chemicals after deposition or preventative by scale inhibition squeezing. Scale squeeze refers to coating the inside of the pipe with a scale resistant chemical layer with the objective to delay deposition of scale. There are special requirements for disposing of radioactive material and the radioactive material is repository stored at different bases along the Norwegian coast.

If the subsea well is tied back to a platform, the platform has to issue a well handover certificate to the intervention vessel before the vessel can commence work and take electric and hydraulic control of the well. Approval is also necessary when the vessel wants to enter the 500 m radius safety zone. Consent is granted when the platform has carried out integrity tests on the XMT valves. The subsea equipment is always tested prior to arrival on well site.

All equipment should also be function tested at surface before run in the well if possible, and pressure containing equipment has to be pressure tested. The test area should be sealed off. It is important to be vigilant of umbilical, hydraulic hoses and guide wires when handling such equipment and when skidding on deck. Communication is a crucial and very important component of the operation. Before any operation is started the following communication equipment is tested [35]:

- Clear-com system (primary communication system, fixed cable on board the vessel)
- Ultra High Frequency (UHF) radio (secondary communication system)
- DP Alert System
- Public Address (PA) System
- Satellite and/or mobile phone (to platform CCR (Central Control Room))
- Very High Frequency (VHF) Radio

Another important precaution is the “Tool Box Talk” (TBT). This refers to a meeting between the central parties (supervisors) and contractors relevant for the next operational step. It is important to discuss the programme requirements, review permit requirements and relevant risk assessments. SJA (Safe Job Analysis) is a common tool offshore in the North Sea and it is expected that anyone that feels uncomfortable or have seen something that is a potential risk calls a “Time Out For Safety” (TOFS). It is also necessary to address any special circumstance i.e. weather, well conditions, safety issues, contingency procedures and equipment readiness. In addition it is usual to address lessons learnt from nearby wells, pressure ratings of equipment, max operating pressure (MOP) and MAASP (Maximum Allowable Annular Surface Pressure). Making sure everyone knows their specific duties and responsibilities is vital.

Other fundamental considerations that have to be done before commencing operations are to ensure that the weather window is sufficient and that currents are within acceptance criteria to perform the planned operation safely. There is also a special need for metallurgy that can withstand long periods under water. Examples are 13% chrome steel, stainless steel and nickel steels. Corrosion is very important to combat, protect against and monitor.

Highest and lowest astronomical tide (HAT and LAT) are determined by inspecting predicted sea levels over a number of years thus does not denote the extremes. It is common to denote water depth in meters LAT referring to the lowest levels that can be expected under average meteorological conditions and under any combination of astronomical conditions [36]. Actual conditions are closely related to these measurements. The importance of depth control during all subsea operations cannot be expressed enough.

A simplified overview of a general subsea intervention operational procedure:

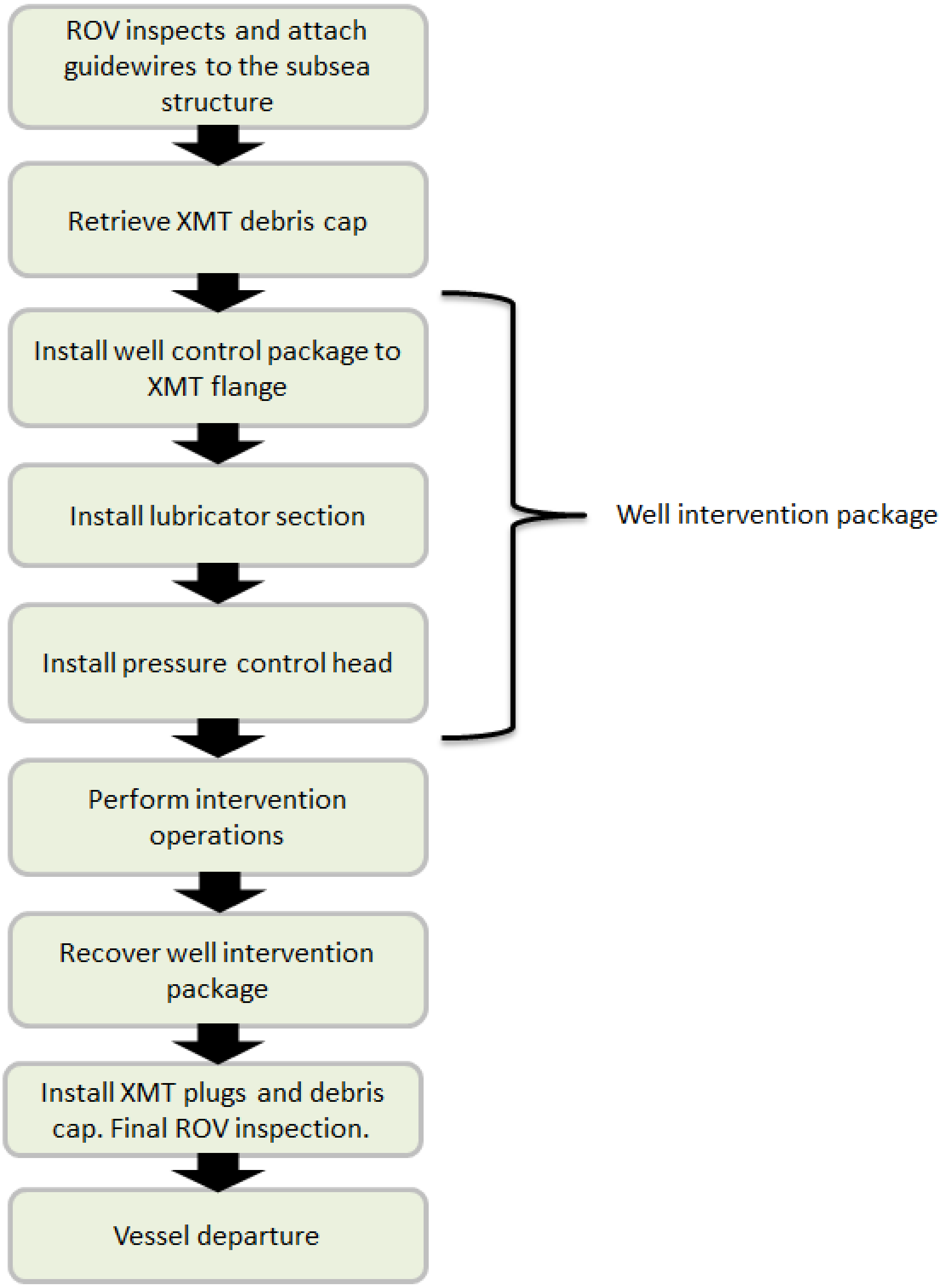


Figure 15: Major components of a subsea intervention procedure.

A typical pressure and equipment flushing procedure can be found in appendix E.

3.5.1 Set up and deployment systems

3.5.1.1 Module Handling Tower

The module handling tower (MHT) or derrick is the focal point for operations and is situated directly above the moon pool. It is made up of a work basket, cranes, different kinds of wires, tuggers and a main winch which are used in various combinations to allow for various rig-ups. The subsea well intervention package is deployed through the moon pool, after opening the hatches. The safe working load for the MHT varies with the vessel. It can lift with heave compensation or with constant tension. On modern vessels the MHT is equipped with guiding frames. The upper frame guides the main hoist hook while the lower frame is used for protection and controlled deployment of equipment through the splash zone (= in and out of water motion due to heave and waves). The tower control room overlooks the moon pool and MHT area, and functions as the central control room for the subsea intervention operation.

Figure 17: Module Handling Tower [23]

Figure 16: Derrick with SIL and TRT (Tree Running Tool) installed awaiting deployment [37]

3.5.1.2 Moon pool

The moon pool is a vertical opening in the hull and is used to lower equipment down to the well. The moon pool hatches are normally closed but opened when needed. The moon pool provides some protection from the open seaways but the water inside the moon pool system can oscillate up and down, and in special resonance situations cause amplitude build up. This can flood the deck or cause unacceptable loading. This obviously affects the possibility of launching and retrieving any equipment in rough weather conditions.

The fluid motion in the moon pool can with some reasonable assumptions (incompressible fluid, vertical acceleration component only, neglect viscous forces) be described by the Bernoulli equation. By reducing the Laplace equation it can be showed that water in the moonpool will act as a mass spring system [38]. This derivation is considered to be outside the scope and focus of the thesis.

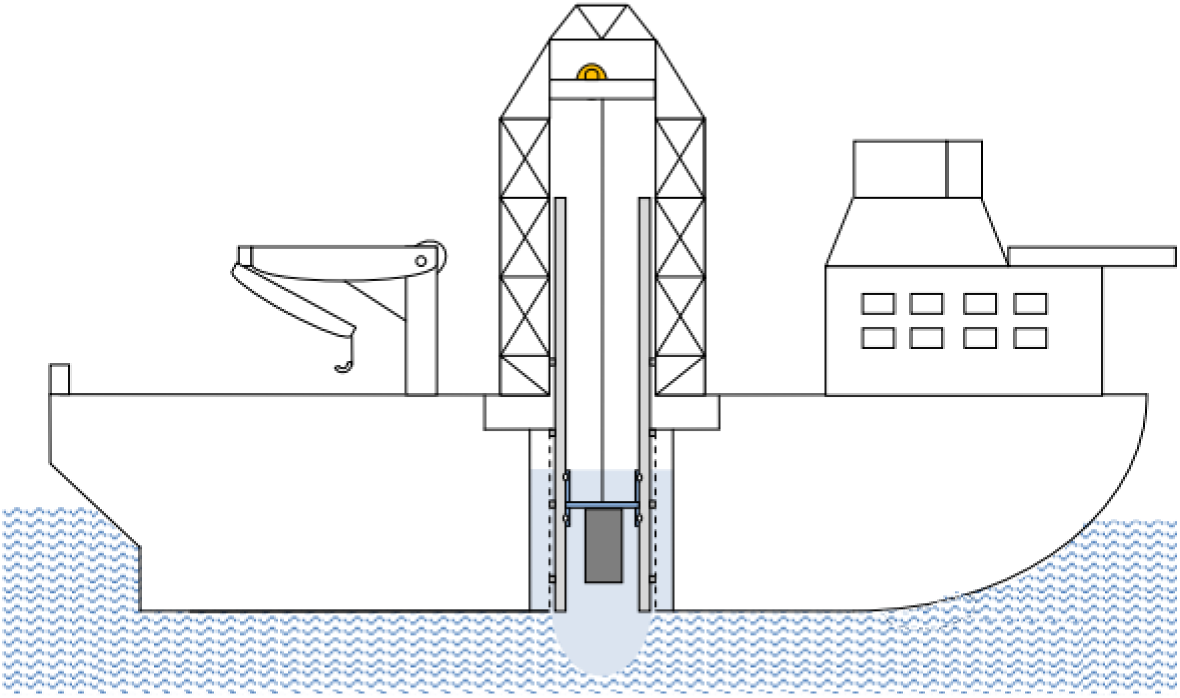


Figure 18: Moonpool Concept [38]

3.5.1.3 Skidding system

A skidding system is used on deck to ensure safe handling of heavy equipment and is driven by two hydraulic skid units. There is one main skid leading into the moon pool, and several “side-skids” to park pallets.

Figure 19: Skidding System Layout [39]

3.5.1.4 Umbilical

The umbilical (or control cable) supplies power and signals to control the subsea unit. It is important to be cautious when skidding and running equipment with umbilical and hydraulic hoses into position not to trap and rupture them. The umbilical has an umbilical termination head (UTH) and needs reels on the vessel for handling of the long lines. The umbilical is also heave compensated while in operation. There might be several lines in the water at the same time during operation and umbilical management in itself is critical in such phases. The control umbilical is the only line that is deployed with the subsea intervention lubricator except during pumping jobs when a pumping hose or kill line is run in addition. It contains all the necessary connections between hydraulic lines, flush lines, return lines and fibre optic control cables. The umbilical termination head is connected to the WCP by ROVs but can be disconnected hydraulically in case of emergency. The termination head also converts fibreoptic signals to electric signals. A chemical injection line is also included in the umbilical and kill hoses can be connected if deemed necessary.

Figure 20: Cross-Section of Aker Composite Umbilical [40]

3.5.1.5 Hot Stab

Hot stabs are BOP tools and can be used by ROVs or divers to access the well if main valves are damaged or in some way obstructed. Hot stabs are used to power hydraulic tools, transfer fluid, operate actuators, perform chemical injections and to monitor pressure [41]. The system is made up by male and female mating halves. The female receptacle is permanently mounted to the subsea system, while the male stab is connected via a flexible hydraulic hose normally inserted by a ROV [42]. It is noted that FES International has developed a hot stab that can be hydraulically operated which the company claim eliminates the need for divers to provide the connection [43].

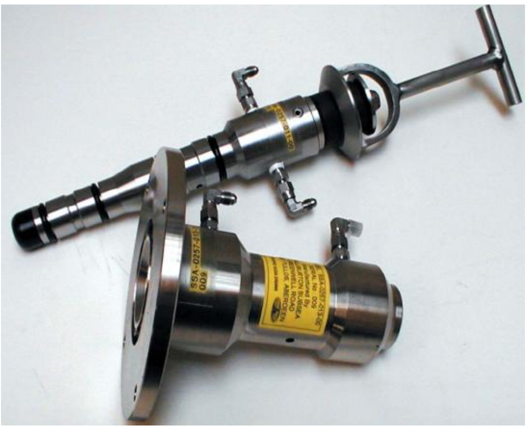


Figure 21: Dual Port Hotstab

3.5.1.6 Tree running tool

The tree running tool is used as a lifting device to lift the subsea tree in place or retrieve it back to the vessel if the tree is to be repaired or exchanged.

3.5.1.7 Kill line

A kill line (2") is deployed when needed for pressure testing and pumping operations. It is a high-pressure pipe leading from an outlet on the BOP stack to the high pressure rig pumps, and is used if the drillpipe is inaccessible for kill operations or simply as a redundancy. In floating operations, the choke and kill lines exit the subsea BOP stack and run along the outside off the riser or wire to the surface.

3.5.2 Well Access and Pressure Control

3.5.2.1 Wellhead

The wellhead (WH) structure has several functions. It provides the structural foundation for the XMT and well intervention systems and it is also part of the barrier envelope containing pressure from the well below. In addition to this it acts as a suspension point for well tubular. To be able to access the well, one has to pass through the subsea XMT which sits on top of the WH. Wellhead fatigue has recently become a focus area, gaining RLWI another advantage due to its low WH load impact.

3.5.2.2 Christmas Trees

A XMT is the set of valves (valve stack), spools and fittings connected to the top of a well to isolate, direct and control the flow of wellbore fluids. Alternatively it can be defined as the control valves, pressure gauges and chokes assembled at the top of a well to control the flow of oil and gas after the well has been drilled and completed while integrating with the wellhead as the well is prepared for service (production or injection) [44].

Vertical XMT (the original):

Any intervention has to pass through the master and swab gate valves (traditionally 7" inner diameter), limiting the tool string size. The wellhead is installed first followed by the tubing hanger, the subsea tree and finally the tree cap on top.

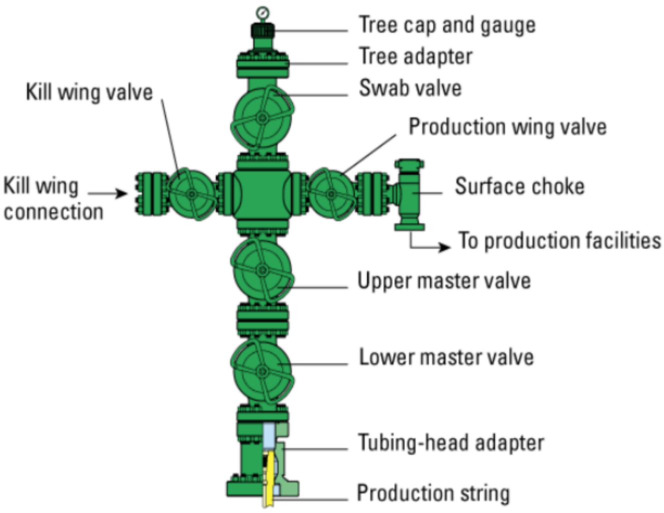


Figure 22: Component Overview of a Vertical XMT [44]

Horizontal XMT (the modern version):

The horizontal subsea tree concept evolved from early through bore tree concepts as a means to be able to retrieve production tubing and downhole equipment “through the bore” of the subsea tree in an effort to simplify equipment and workover operation in troublesome wells where frequent workovers are necessary. A horizontal tree also makes it possible to drill the last hole section with the tree installed below the BOP.

The functions are the same for both trees (vertical and horizontal) but the valves are in other positions. Swab valves are made redundant by the tubing plug in the tubing hanger and the sealing tree cap. The tree cap provides the second pressure barrier behind the tubing hanger and backing up the tubing hanger annulus seals [45]. The horizontal arrangement means that it is possible to mix different production tubing sizes (full bore capability), bore spacing and downhole interfaces without affecting tree valve and flowline equipment configurations. A considerable downside with this layout is that damage to the seals during intervention may result in having to kill the well.

The horizontal XMT makes use of an internal tree cap or an extended tubing hanger. Crown plugs (also called isolation plugs) are installed as barriers (upper and lower). These are usually rated to 10 000 psi, or what is needed by the design. Large bore configuration allows operators to access the well easier. Vertical access to downhole equipment through a conventional marine drilling riser and subsea BOP is made possible. Flowlines and umbilicals can be left alone, handled separately. If main components of the tree fail, one would have to pull the completion to replace the tree. Minor components are often (ROV or running tool) replaceable without having to pull the entire tree. The tree is installed directly on the wellhead, and the tubing hanger and tree cap is installed afterwards.

Figure 23: Horizontal XMT [46]

3.5.2.3 Subsea intervention lubricator system

There are various names and versions of the subsea components supplied by various vendors and used to connect to the well, but the concept can be described by the following general illustration:

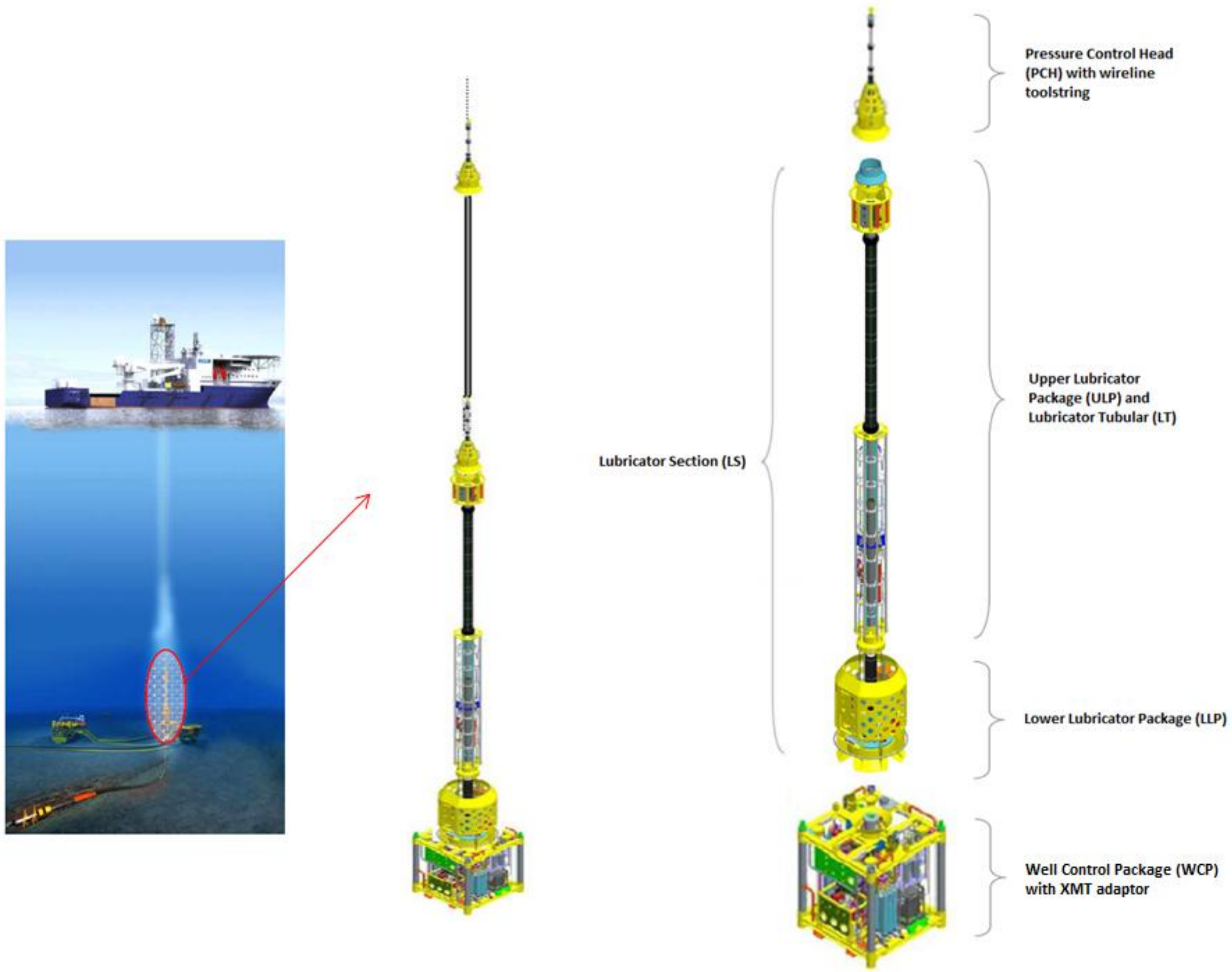


Figure 24: Complete Subsea Intervention Lubricator System [47]

3.5.2.4 Well Control Package

The WCP is the main safety barrier during the intervention operation in case of well control or drift off emergencies. It serves several functions [23]:

- Shear / Seal Ram cuts wireline, CT and wireline tool string and seals off the well
- It enables flushing of hydrocarbons back into the well
- It provides local hydraulic pressure from a pressure supply bank as well as communication to the XMT functions.

The well control valves such as shear ram, blind ram, gate valves and ball valves are located here. The gate valve can also be used as a barrier during entry or exit when using short toolstrings. The ball check valve may be used to cut wire in an emergency, and can also be used as a barrier in emergency situations due to its sealing capability.

3.5.2.5 Lubricator section

The Lubricator Section (LS) or SIL consists of three main elements:

1. Upper Lubricator Package (ULP)
2. Lubricator Tubular (LT)
3. Lower Lubricator Package (LLP)

When a toolstring is deployed with the PCH, the tool string is stabbed into the subsea lubricator section. The length of the LT decides and restricts the length of the tool string that may be used. Grease is then injected from the reservoir unit contained in the lower part of the LT to the PCH to provide a liquid seal around the wire [23]. A steady differential pressure between the WHP and grease pressure is maintained for precise flow and pressure control. The lubricator section makes up the connection between the WCP and the PCH.

The main function of the ULP is to provide a barrier element during well intervention. Inside the ULP there is normally also a ball cutting valve (ball check valve, section 3.5.2.8) that can cut the wire in an emergency situation. It also has an upper circulation valve which allows subsea flushing of hydrocarbons from the lubricator to the well.

The SIL is used for well control when connecting to a well. It is also necessary for equalising the pressure to be able to enter the well safely.

The LLP includes a safety joint which is designed to be able to bend if the subsea stack is subject to excessive lateral forces. In addition to this it contains subsea control modules (SCMs), electrical power supply, power, accumulators and Hydraulic Power Units (HPUs) to support all LS functions.

3.5.2.6 Pressure Control Head

The main functions of the PCH (also called grease injection head or liquid seal head) are [23]:

- Pressure barrier toward the well by a liquid seal around a moving or stationary wireline during well intervention
- Final interface barrier between the well and the sea water environment

- Grease injection point for pressure control
- Toolcatcher function to prevent loss of tool string
- Mono-Ethylene Glycol (MEG) injection (hydrate inhibitor) capability to prevent hydrate formation

Grease is injected in between the pack off sections in a similar manner to a surface braided line (described later in the wireline section) pressure control rig up. The PCH has a dedicated running tool and is guided by two guide wires when run. The toolcatcher has a dual function; one as mentioned to prevent loss of the toolstring into the well but it is also used to latch onto the rope socket of the toolstring during wireline exit and entry pressure testing. The assembly is lowered in sequence starting with the lower part that will connect to the subsea structures first.

The Chemical Injection Unit (CIU) is used to flush the lubricator section during well entry and exit and methanol hydrate inhibitor is used to avoid hydrates formation during operation.

3.5.2.7 Toolcatcher

The toolcatcher is a safety device located under the dual stuffing box or PCH and above the lubricator section. Its purpose is to prevent a possible fishing job should the toolstring be inadvertently pulled into the top end of the lubricator. When the tool is pulled up into the toolcatcher it latches into a collet assembly where it is held safely until the catcher is hydraulically activated to open.

3.5.2.8 Ball Check Valve

A ball check valve is a secondary safety feature located inside the toolcatcher between the piston carrier and the piston spacer. When the cable is threaded through the valve, the ball is forced to one side of the housing. If the cable is removed, the velocity of any escaping gas pushes the ball upwards and inwards to seal on the ball seat. This effectively stops all flow from the well. The well pressure will then keep the ball seated, the greater the well pressure, the tighter the seal. The ball check valve in the toolcatcher will only be deployed if there is no wire running through the toolcatcher, thus it does not provide cutting capability (as it does in the WCP).

3.5.2.9 Shut down procedures

Emergency Shutdown *(*ESD*)* entails a controlled shutdown of the subsea system in a managed sequence to ensure proper functioning of the various valves. The wireline will normally be cut by the Cutting Ball Valve (CBV) or the Shear Seal Ram (SSR). The ESD shutdown initiation starts two independent sequences. Valves are closed in in a pre-programmed sequence and ensuring that all barrier valves go to safe mode in the case of loss of communication or power.

The Emergency Quick Disconnect (EQD) is needed in case of loss of Position (Drive Off and/or Drift Off). There are pre-defined DP circles with green, yellow and red status where red requires EQD activation to ensure systems and well integrity.

3.5.3 DP Systems

Dynamic Positioning (DP) refers to systems for control of position and heading (station keeping) of a floating unit by means of active thrust.

The first things the vessel do when approaching the 500 m zone is to carry out DP trials and system checks.

The dynamic positioning system is divided into three classes [13]

Class 1: Single point failure will cause loss of vessel position

Class 2: Single point failure will not cause loss of position

Class 3: Single point failure plus risk of fire and flood without loss of position is considered in the design phase of the unit.

Class 3 includes two separate engine rooms, two separate electrical switchboards, and the unit must survive a complete compartment loss through fire or flood and still be able to perform necessary station keeping.

We remember that the DP system only controls three of the six degrees of freedom (horizontal plane). These are surge, sway and yaw. The movement in the vertical plane is handled by compensation systems. The last two are just monitored and not controlled.

The following are the limits set for a typical CAT A DP3 vessels to ensure safe well operations. Any vessel contracted by BP need to be able to operate up to these limits:

Minimum Intact DP Capability	Category A
	Monohull Unit
Wind	40 knots
Significant wave height (Hs)	5.9m
Wind direction sector	+/- 30 degrees around head
Resultant current (sum of surface and subsea)	1.6 knots
Current direction sector	+/- 30 degrees around head

Table 4: Category A Vessel Limitation and Specification Criterion [14]

+/- 30 degrees around head: The vessel have to be able to maintain its bow within this heading.

3.5.4 Heave Compensating Systems

Heave is the vertical motion taken by a vessel at sea. This is the most critical as it directly affects the position of the tool string and subsea equipment being lowered towards the well. There are three main types of compensation systems [48]:

1. Passive system (pneumatic)

The principle for passive heave compensation system is to function as a pneumatic spring. This is achieved by suspending the load from large hydraulic cylinders that are connected to an accumulator. The heave/load is compensated passively by compressing air in a piston-like manner.

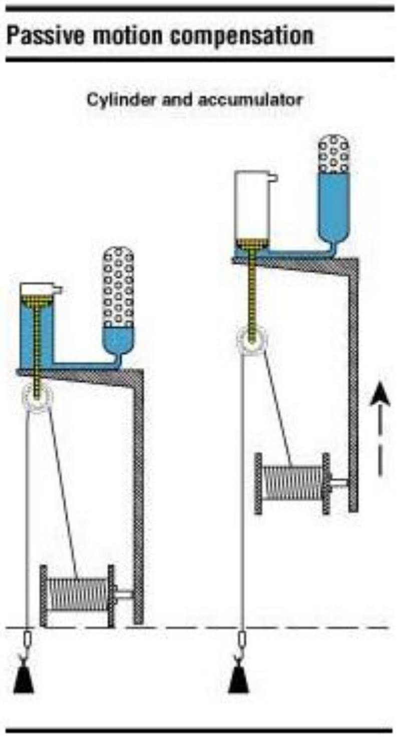


Figure 25: Passive Motion Compensation [49]

2. Active system (hydraulic)

Active systems are powered directly by a large hydraulic power supply. The system is continuously adjusted to keep the load as steady as possible.

The conventional compensation systems have been built with an accelerometer package that measures the vertical motion. The outputs are integrated twice (since the derivative of distance yields velocity and the derivative of velocity denotes acceleration) to determine vessel heave displacement, and the result of the calculation determines if cylinder strokes are to be retracted or extended. The cylinder moves opposite to ship heave.

There are other ways of operating compensation systems on the market (offered by several vendors in various styles); Schlumberger for instance has an electro-hydraulic winch, supporting piston sensors with electronics and software to regulate cable slack. Tower Crown Mounted Compensators (CMC) is the standard system, but several compensation systems are available depending on application. Over the whole range of oil tool equipment and systems, service companies are always trying to develop improved solutions.

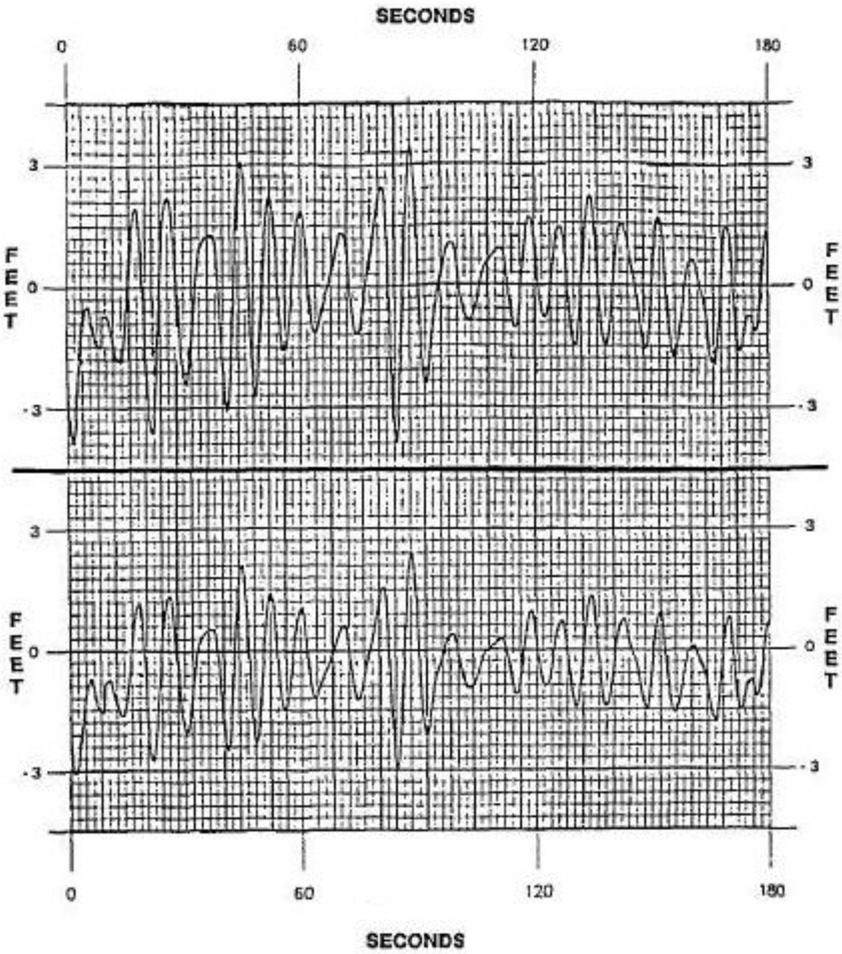


Figure 27: Active Motion Compensation Function. Top graph shows accelerometer calculated heave and the bottom one shows traveling sheave position [50]

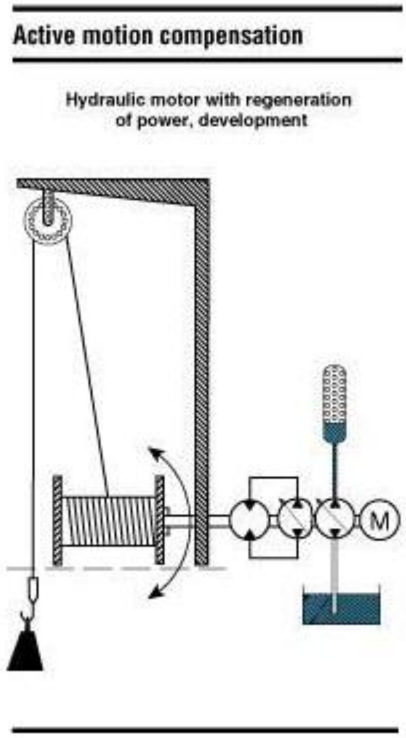


Figure 26: Active Motion Compensation [49]

3. Semi-active system (mix of pneumatic and hydraulic)

This system is primarily passive, but hydraulic power is applied to the system to neutralise friction losses. The system saves a lot of energy compared to a fully active system. The compensation system is also limited by its total stroke capability (usually 6 meters, 3 in each direction), and limits set to stay within safe operating conditions in relation to this.

Lowering speed while connecting subsea equipment onto the well is extremely restricted with speed not permitted to exceed 0.1 m/s for the WCP and 0.5 m/s for the LS.

3.5.5 Remotely Operated Vehicles (ROVs)

ROVs play a central role in a successful subsea LWI operation. Before the well is touched, an observation ROV goes down to carry out an inspection of the well and the immediate surrounding area (a so-called “As Found” survey). This survey often includes jet cleaning of organic material (marine growth) from the tree hub and performing inspection of possible well leaks.

ROVs are also needed to guide and connect guide wires to the well structure at the sea bed to make it possible to land equipment safely and with position control. If a ROV does not have a specific task it is often used for surveillance purposes and as such being online for the entire operation.

A LARS system (Launch and Recover System) is used to launch the ROVs, and is powered and connected to the LWI vessel by a dedicated umbilical [23]. The ROV can be used to pick up and manipulate objects such as debris caps, umbilical and hose management and such by use of its mechanical arms (manipulators). Torque handles must be set up so the ROV does not damage any of the tree valves when applying forces. Other equipment available for ROV services are sonar, gyros, video camera, cleaning and cutting tools.

There are three main types of ROVs:

- Work ROV
- Observation ROV
- SSTV ROV (smaller and simpler observation ROV)

If ROVs are unable to perform a task, stand-by divers are called to assist if water depth permits the use of divers. Diving is still done to some degree (especially in the UK) in spite of a troubled North Sea divers history. Since diving operations are expensive and puts divers at risk, most operating companies focus on development of subsea systems to make installation and intervention totally independent of divers.

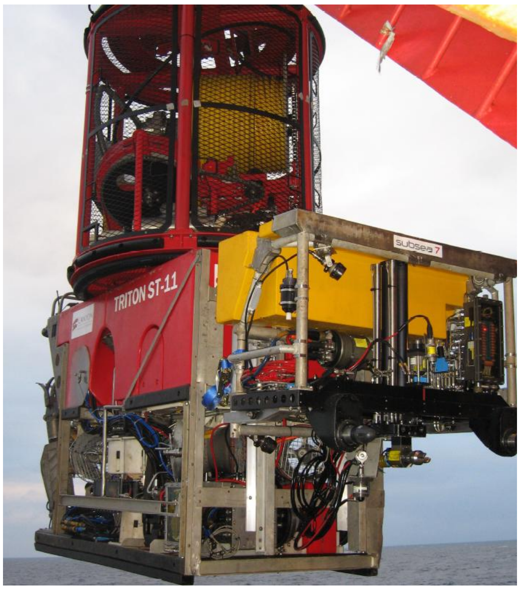


Figure 28: Work ROV Launched From the Seawell [37]

3.6 Intervention Work Capabilities

The complete well intervention scope is quite large. The figure below gives a broad overview:

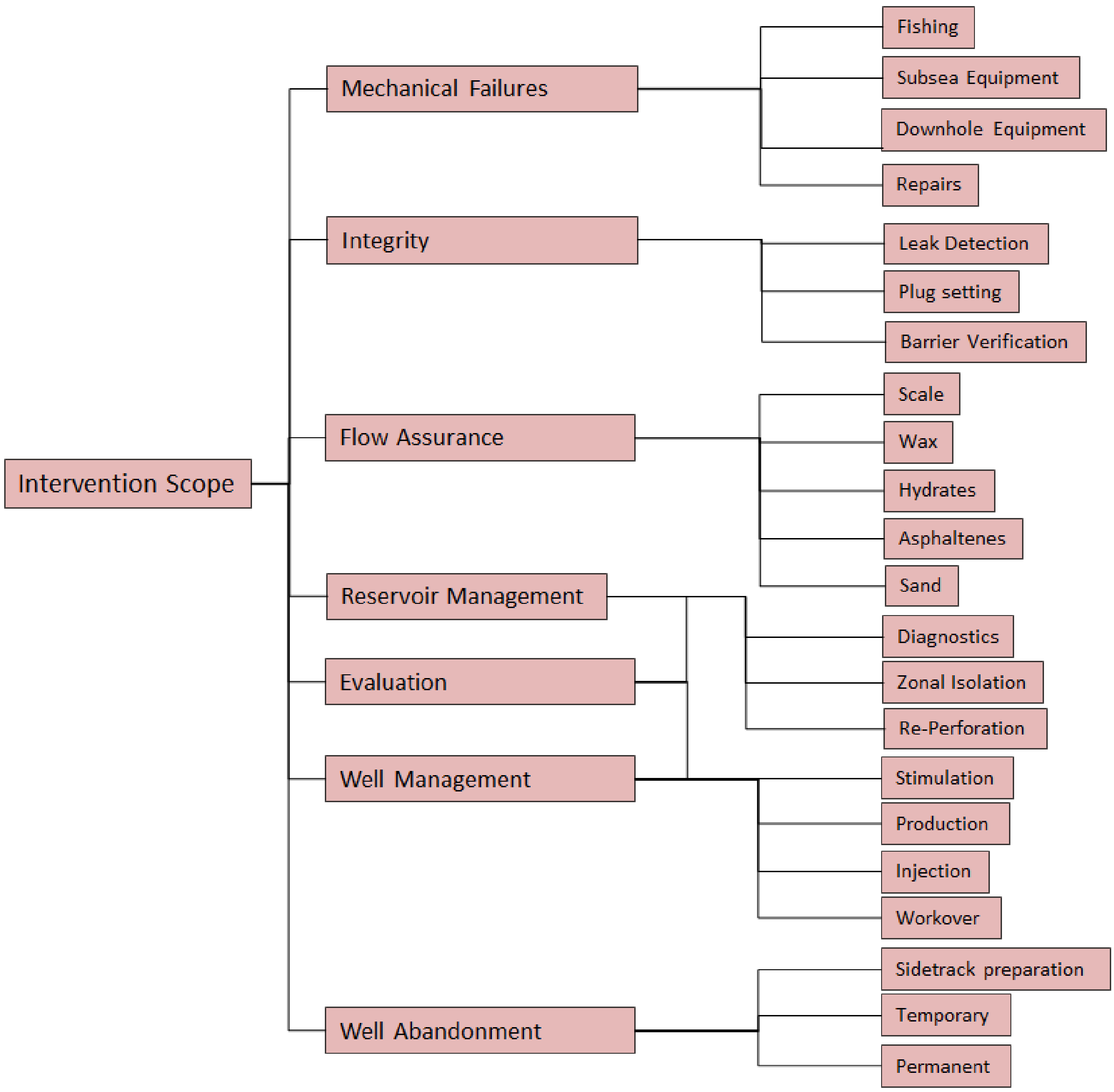


Figure 29: Intervention work scope.

In addition to the above figure, intervention jobs also include removing of severe blockages and restrictions, installing packers, fishing obstructions, control of unwanted water and gas influx, spotting (placing) screens, restoring production in watered-out wellbores, camera inspections, well killing, obstruction milling, tubing cutting, tubing punching, installing or servicing subsurface surface-control valves, changing gas lift valves or change of other downhole jewelry [51]. Intervention may also be conducted to improve dynamic understanding of the reservoir sections.

Intervention work usually follows the well management loop:

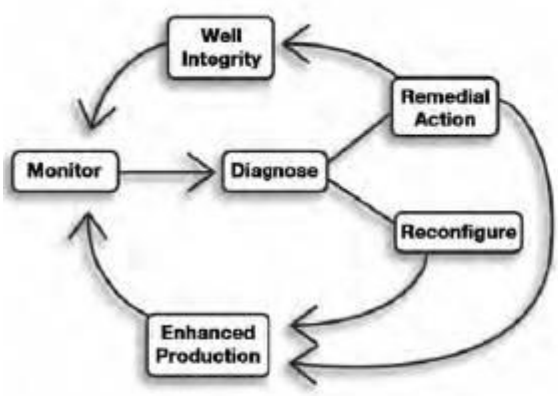


Figure 30: Well management loop [52]

Since CT is not presently part of the RLWI capability, the well workscope is limited to pumping and wireline operations including plugging, perforation, logging, milling of debris or scale and subsea operations like pulling and setting XMT, tubing punching, circulate, leak detection and bailing (remove) debris.

3.6.1 Plug and Abandonment of wells

The plug and abandonment operations for the Tommeliten subsea field (which was Statoil's first discovery) [53] were partly performed by light well intervention vessels. CAT A vessels are now increasingly being used to prepare and finalise wells for abandonment (by running plugs, pulling Christmas trees, etc). A rig is still needed to cut and pull casings and completion strings before final plugging and cementing the hole. In other parts of the world (Africa), LWI vessels are performing total well abandonment campaigns but under very different and relaxed sets of regulations and inadequate company requirements.

3.6.2 Intelligent completions

Intelligent completions are sometimes claimed to create interventionless wells. There is so far no conclusive evidence that supports the interventionless well concept. All well needs some sort of intervening sooner or later. Experience shows that something mechanical fails or that wells start depositing scale or hydrates. Dry gas wells are maybe the closest to maintenance free wells but far between in reality. The logic of maintenance free wells is complicated by the fact that more equipment downhole often equals more malfunctions. Subsea completions come into plat when reservoirs are no longer reachable with seabed set platforms and pay zone reservoirs are too small to justify building an expensive platform. Hydraulics or electric power is needed to manipulate completions and valves. In general intelligent completions are frequently considered less robust and with too many expensive components. These skepticisms have to be over-won by smart completion believers before intelligent completions can become the preferred approach by the major oil companies.

3.7 Conveyance Methods

In the following a description of the different intervention conveyance technologies will be provided. There are four central conveyance methods. These are

- Pumping
- Wireline
- Coiled Tubing
- Tubing Conveyed

Tubing conveyed intervention is done from rigs with pipe handling and torque capability, and is not part of the LWI scope. Coiled tubing is a possibility through use of different riser systems, but the two main conveyance methods for LWI vessels are wireline and pumping operations. These do not require riser systems, and have proven to be effective for their application area. It is obvious that this limits the LWI capabilities in relation to a workhorse rig.

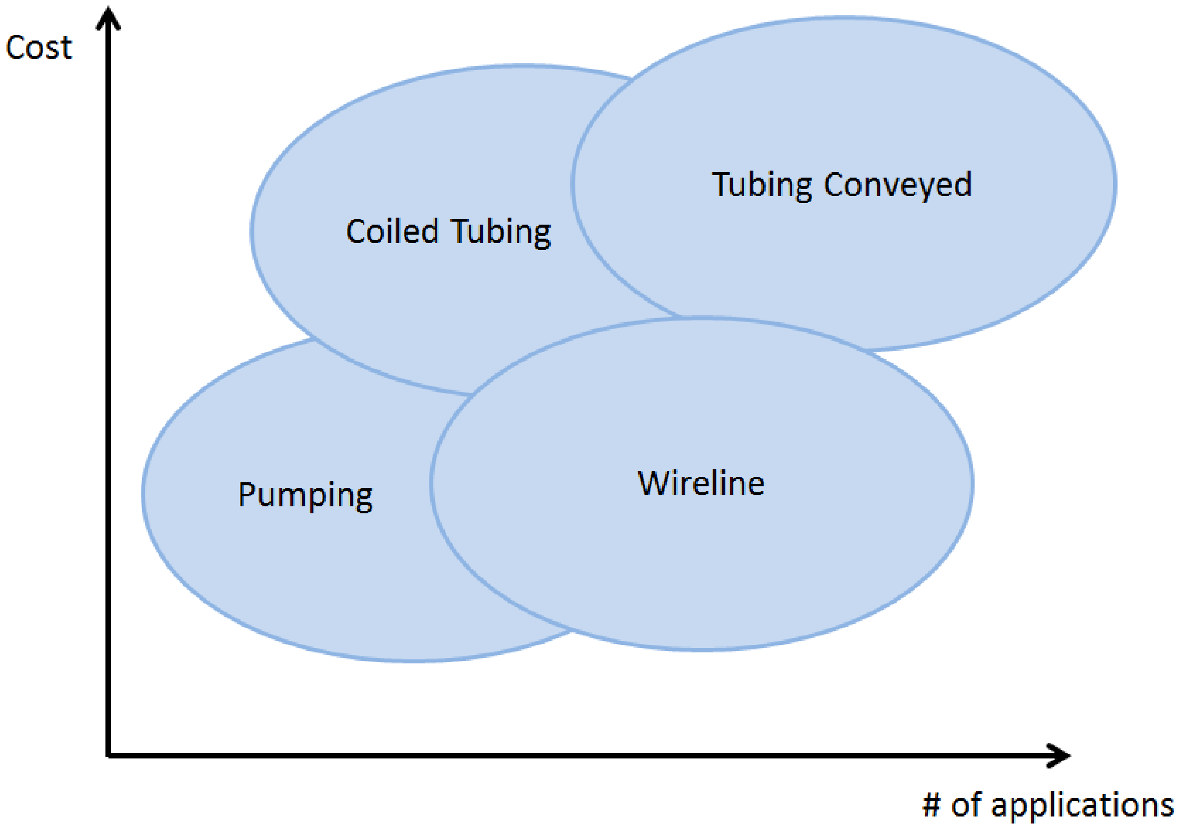


Figure 31: Relation between Cost and Number of Applications for Different Conveyance Methods

3.7.1 Pumping

Pumping jobs are most often performed as bullheading jobs since LWI subsea well interventions normally do not allow for circulation in and out return passages. One should not be fooled by the apparent simplicity of pumping operations, as application of excessive hydraulic pressure can lead to formation breakdown, mud losses and a subsequent blowout. It is essential to never violate fluid rate and pressure limitations. Pumping operations provides a wide range of applications:

- Diagnostics (i.e. LOT and XLOT)
- Scale Squeeze
- Stimulation
- Tracer Injection
- Washing / Cleaning
- Water management
- Formation damage
- Combined treatments
- Kill capability

Jetting action can also be used to clean and cut the pipe. During pumping operations an additional line (kill line) is normally rigged up to the lubricator section. This allows any fluid to be pumped into the well by an independent high pressure pump. The vessel require a set-up of hoses, valves, tanks and pumps to perform pump operations.

3.7.2 Wireline

Wireline refers to cabling technology where operators attach tools at the end of a cable or wire and then lower them down the well through a stuffing box by an electro-hydraulic, diesel powered or fully electric driven winch. There are three types of cable technology:

1. Slickline
2. Braided line
3. Electric line (E-line).

Slickline tools operate with mechanical action (such as jars). The slickline toolstring consists of a rope socket, stem (weights) or roller stem, jar and different tools that can be attached at the bottom. The main pressure control is the stuffing box that consists of rubber packers that seals around the line. Well pressure forces the packers together, but extra hydraulic pressure can be applied if leakages occur. The stuffing box is the primary barrier.

The higher the well pressure, the more weight is needed to get tools down the well. A lubricator is used to equalise the pressure on both sides of the BOP so it can be opened and the tool run in hole. This means that the length of the toolstring is limited by the length of the lubricator as described earlier. A wide range of tools and equipment can be attached at the end of a slickline [54]:

- Running tools
- Pulling tools
- Gauge cutter
- Lead Impression Block (LIB)
- Bailer
- Go devil wire cutter
- Wireline finder
- Broach

A weight indicator is used to monitor the string. Varying weight can be caused by restrictions, change in fluid density, high amount of cables in the well or a combination of these. Careful follow up is needed.

The braided line is stronger than slickline. To ensure pressure control the braided wire runs through a grease head. E-line is a braided wire with electrical cable inside that can transmit signals giving real time capability or power to a tractor. Cable line operations are always carried out with two barriers. The braided cable has a weak point just above the rope socket so it can be easily fished.

The main difference between slick and braided lines is tensile rating and surface pressure control equipment.

Typical wireline jobs include:

- Logging

Different type of logging tools are dedicated to uncover the fundamental characteristics of the reservoir such as porosity, permeability, resistivity, gamma ray, SP. Production Logging Tool (PLT) logs, consists of a fan that rotates (flow velocity). The overall objective of production logging is production optimisation. From the logging tools we generate different types of logs which are spinner log, density log, pressure and temperature log. The caliper log can for example tell us something about corrosion, tubing wear and deformation, scale, holes, cracks and splits, perforation mapping and 3D visualisation. All logs are combined and analysed to give us valuable information about the reservoir and well condition.

- Plugging

Plugging can be used to isolate zones (i.e. if water cut has become too high) or to temporarily seal off the well and function as barriers.

- Re-perforating

To improve well production rates, the well can be re-perforated.

- Drift runs

Drift runs are made to check if there are obstructions in the wellbore, and is a preparation step before running a toolstring in the hole.

* Bailing sand and debris

If debris is found in the hole, it can be bailed out in multiple runs.

Other jobs include but are not limited to:

* Setting and pulling mechanical components
* Open and close sliding sleeves
* Fishing
* Remove scale
* Patching

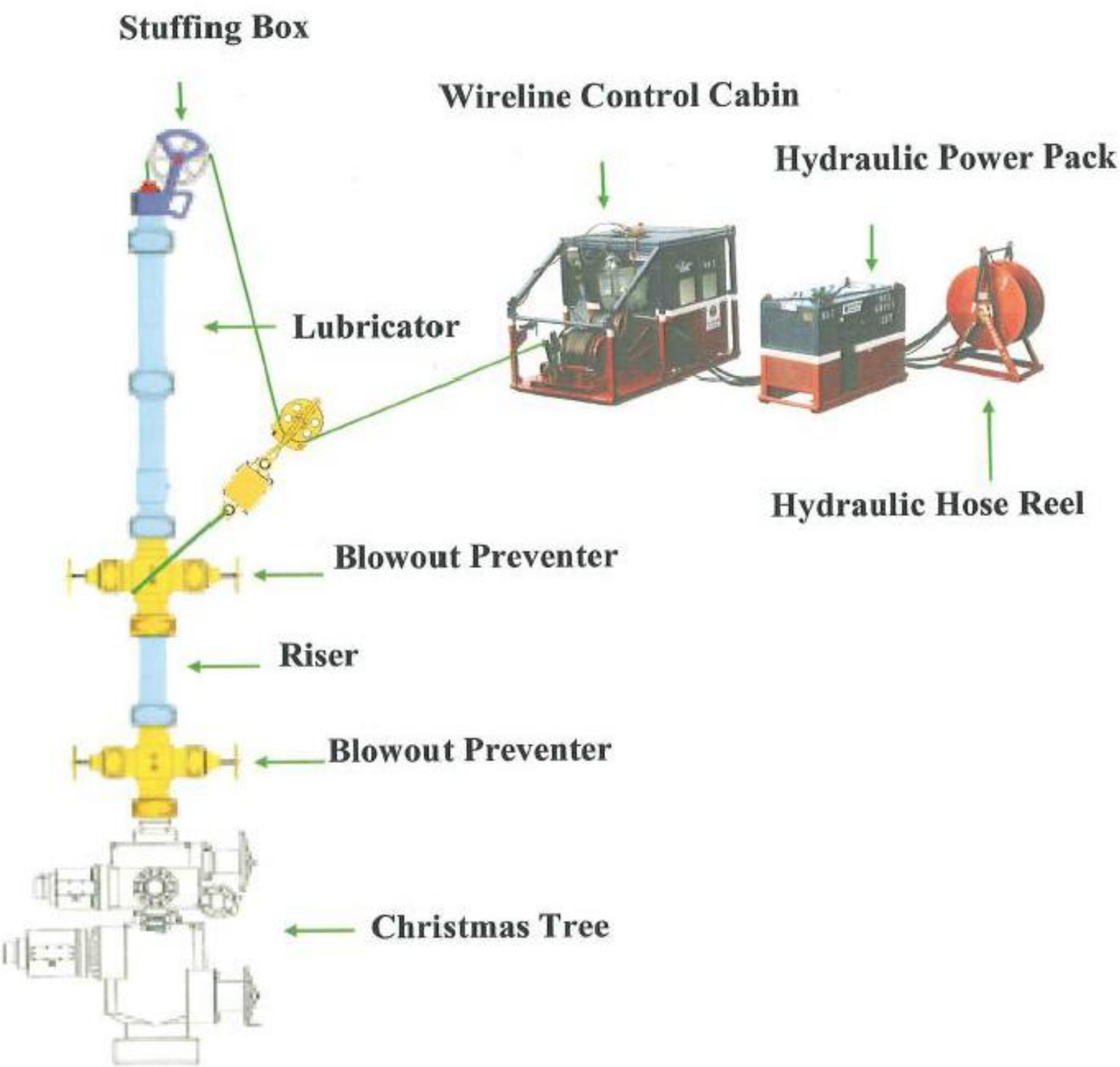


Figure 32: Surface Wireline Set Up [54]

3.7.3 Coiled Tubing

Coiled tubing is a continuous tubing string that is coiled around big reels and with no need to make connections. The tubing diameter is smaller and weaker than conventional drill pipe. It is possible to circulate fluids at relatively slow rates but the tubing itself cannot rotate or tolerate much torque. This challenge can be overcome by installing motors at the bottom of the coil to enable rotation of tools by pumping fluid. The coiled tubing needs an injector head to move in or out of the wellbore in order to properly push and retrieve the tubing [55].

The BP Drilling and Well Operations Practice states that "all snubbing unit hydraulic function shall not exceed the maximum operating tension loads of 80% and operating compression loads of 70% of minimum yield strengths for tubing string used". This is to make sure the coiled tubing is handled within its operating limits. Buckling tendencies and well friction also makes it difficult to reach far out in the well. This can be partly overcome by use of CT tractors.

The main challenge consists of fatigue of the tubing itself [56], and the coil has a limited lifespan. The bend cycle fatigue is increased in offshore operations from floating vessels with heave compensating systems. The mechanical damage consists of:

- Bend cycle fatigue
- Internal pressure loading
- Compressive axial forces
- Corrosion
- Torsional Forces
- Mechanical damage

Oil and service companies have long experience with conventional coiled tubing operations. The coiled tubing unit is heavy and requires considerable deck space. Practical reasons such as transport, weight, lifting and well depth issues induce the need divide the coil into smaller units and to re-splice the tubing later. This is done by connection devices (i.e. Duralink from BJ Services or ReelCONNECT from SLB).

Pressure control is achieved by the stuffing box assembly (strippers) and BOP contingencies. The strippers are classified as primary barriers. The upper is active under operation while the lower is used as a backup.

Applications and typical jobs include:

- Cleanout (remove sand, fill and proppant)
- Perforating
- Logging under tough conditions
- Spotting of fluids (acidizing / stimulation)
- Unloading (nitrogen injection to kick start a well)
- Cementing
- Coiled tubing drilling (not typical, but becoming increasingly popular)

Coiled tubing operations from LWI vessels are possible but can presently not be done commercially. A CT operation was performed from the Seawell (same vessel as BP is currently using) for Shell on the Gannet field in 1997 [57, 58]. The work was carried out by deploying a special riser. Although the operation was claimed to be successful, little public information exist and CT operations from CAT A vessels have not been performed (regularly) since. There are probably too many challenges to overcome, and Seawell owners only carefully advertise CT capability suggesting the same. Total revived a similar project according to rumors where the company tried to perform coiled tubing operation from a LWI but the plug got pulled due to high cost and operational difficulties. Helix Well Ops have picked up the ball and claim to have eliminated some of the issues. Until this is proven the reality is that category B, C and D are the only vessels presently capable of running CT commercially.

The coiled tubing rig up consists of the reel with the coiled tubing. A guide arch is needed to bend the tubing down hole with minimal fatigue load. The lay out is fairly simple and can be seen underneath.

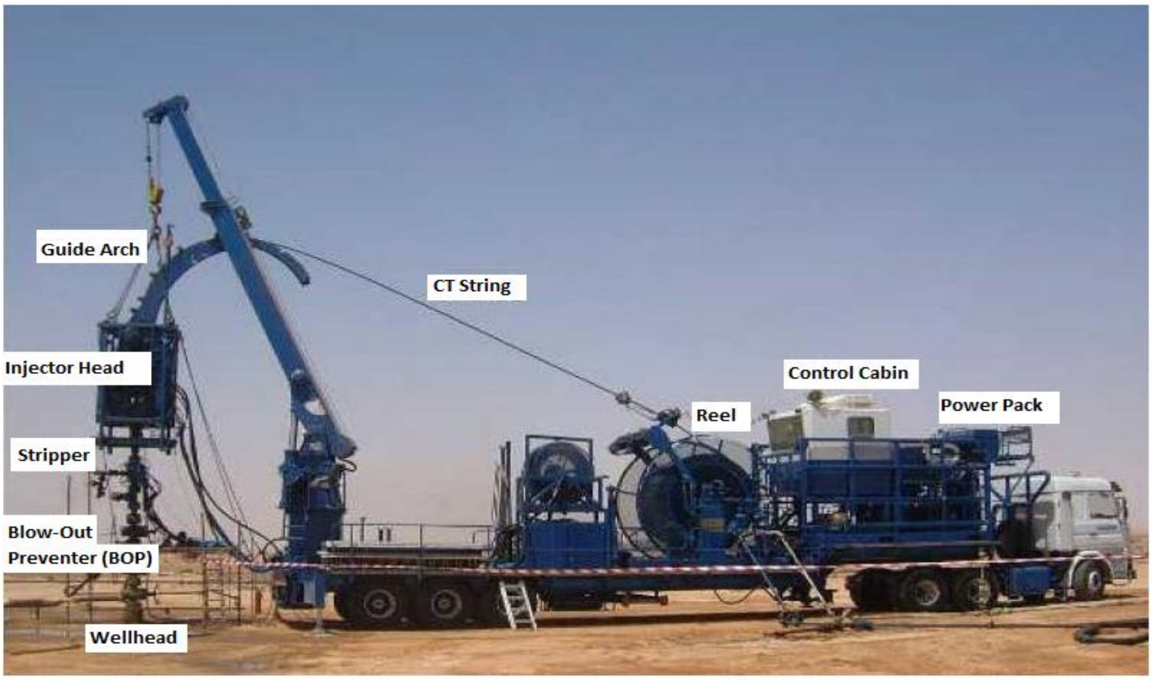


Figure 33: Coiled Tubing Set Up [55]

Figure 34: CT Operation Offshore [55]

3.7.4 Tubing Conveyed Intervention

This type of work usually belongs to workover and re-completion type operations and is not normally designated to well intervention. All work is usually done with a platform, drilling rig full derrick or equivalent.

This category C (and D) option is capable of doing all types of intervention and workover work. It is usually not desirable that full scale drilling rigs takes on simple intervention jobs that could have been done by a light well intervention vessel. The reason for this is the cost of the rig and that it could have been used for drilling instead. If simultaneous operations (simops) are possible, intervention work can be executed while the main derrick is drilling. This requires a complete simultaneous operations risk assessment to ensure safe operation. The CAT C rigs are made with drilling in mind and are not optimised for well intervention purposes.

Figure 35: Aker Barents – a State of the Art 6th Generation Semi-Submersible Drilling Rig [59]

3.8 New Technology

3.8.1 Expro AX-S

The AX-S system is a deepwater (up to 10 000 feet [60]), fully integrated subsea system. It is a technologically impressive piece of machinery and the concept can potentially save the industry large amounts of money by providing quick well access of subsea wells, also in deepwater environments.

The AX-S system emerges as a competitor to the wire through water technology. It operates with a closed pressure envelope with no exposure to water, different from WTW technology. Expro claims this makes the system completely safe with regard to hydrocarbon leaks [52]. After installation it can be left on sea bottom meaning that only connection of a control umbilical would be necessary to access the well. The tower consists of a fluid management package, wireline winch package, tool storage package and a well control package. There are eight working toolstrings contained in the tool storage package that are interchanged at seabed. The idea is to have “everything you need” sitting ready on top of the well.

Among the biggest concerns are the complex nature of the system and the mere height of the subsea stack. Nevertheless, the potential upsides outweigh the downsides.

The solution is still under development, and remains to be field tested but Expro has according to their newsletter [61] signed a long-term (unspecified) frame agreement with Total and will apply this technology on a Total North Sea UK Well in 2012. With the Elegin blowout it can be imagined that this will be pushed back on the priority list. With blowouts both on the UKCS and in the Nigerian Obite field in Q2 2012, well control response has been on top of Total priorities.

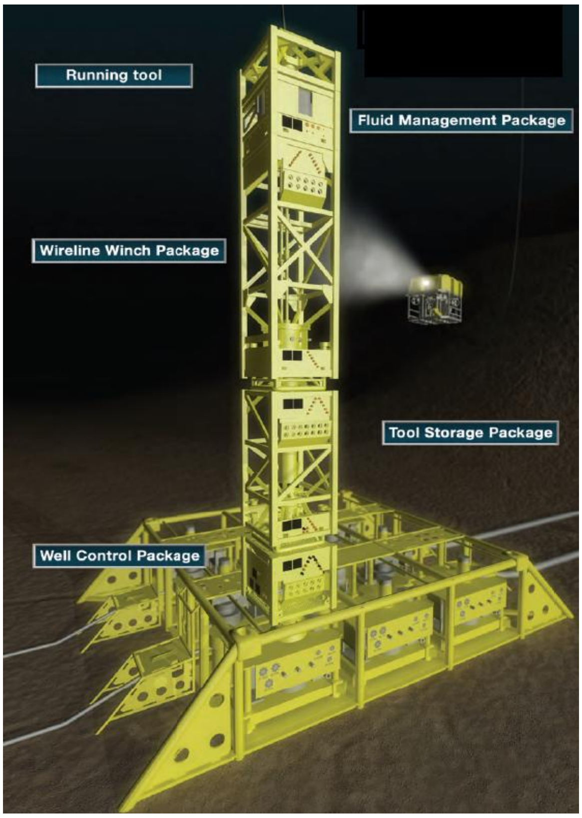


Figure 36: Expro AX-S System [52]

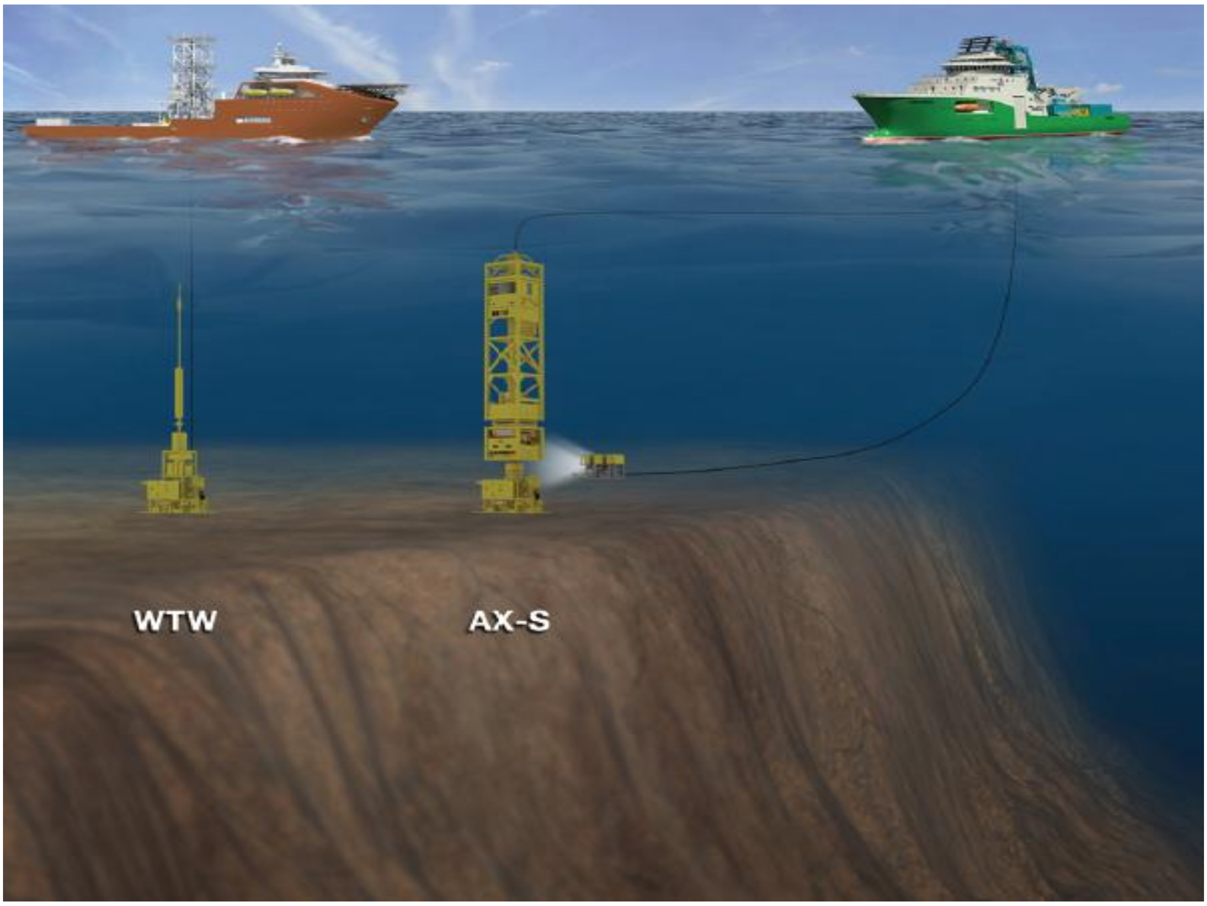


Figure 37: Wire Through Water (WTW) and AX-S System Field Operations [52]

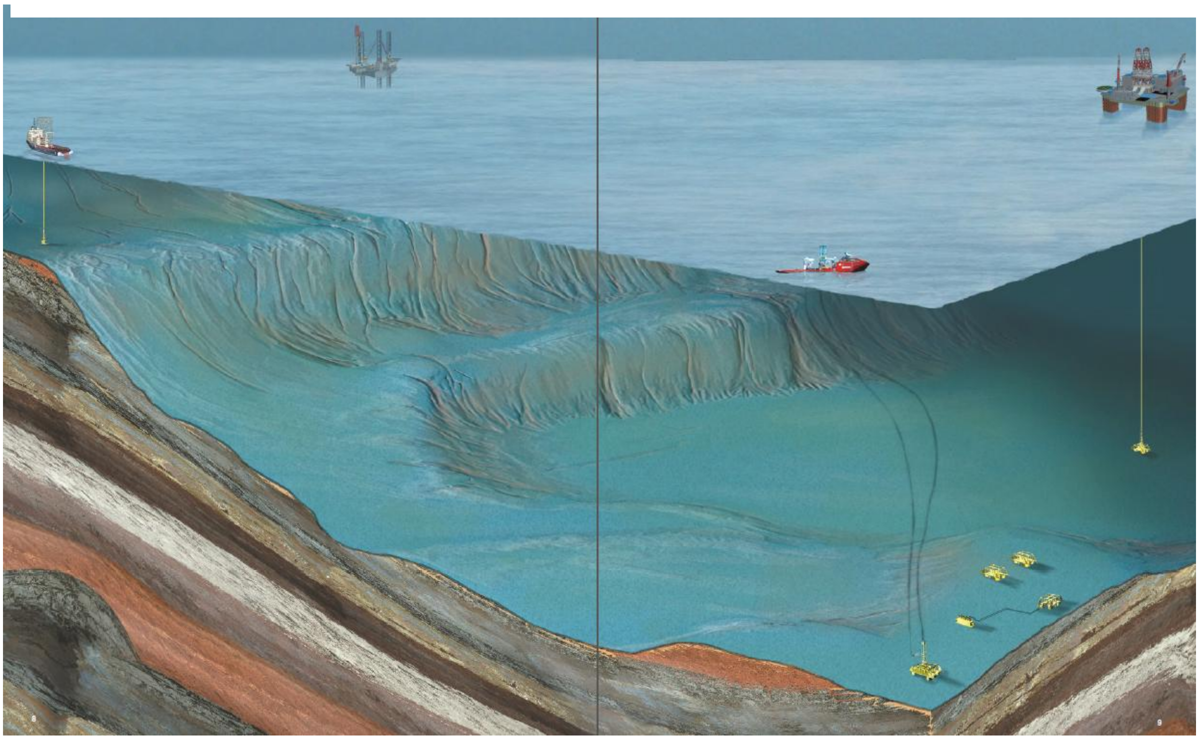


Figure 38: The Expro AX-S System will have Deepwater Capability [60]

3.8.2 Ziebel's Ziplog Tool – A Next Generation Intervention Tool

Ziebel is a technology company that was founded in Stavanger in 2006 [62]. Ziebel's main focus is their "Z-system - Ziplog tool". This logging technology has been studied in detail and the author of this thesis has had several meetings with Ziebel representatives, including a presentation meeting at Ziebel's offices to observe the Ziplog tool up close. Due to a later change in thesis focus, only a short presentation of the system is provided here.

The idea behind the Z-system is to park a 15 mm semi-stiff, self-straightening carbon composite rod into the well to log the wellbore while keeping the rod static (picture below). The idea to perform static logging operations is innovative and while the rod is kept stationary, it can detect any anomaly anywhere in the well during use or manipulation of the well. This is clearly its main advantage, since conventional logging tools require the tool to be in the right place at the right time to discover i.e. a leak. Also, since the logging tool is kept stationary, it does not create noise by moving as conventional logging tools. The Ziplog tool is able to measure DTS and DAS (Distributed Temperature System and Distributed Acoustic System) along the complete length of the rod while point pressure, temperature and vibration is measured by the "bullnose" bottom hole assembly (BHA). This gives the Ziplog a range of applications including well integrity diagnostics (leak detection) and well performance (by monitoring fracture flow, stimulation activities and production profile) [63].

The system resembles coiled tubing in rig up and is currently field tested on dry trees on the NCS. It was run on the Ekofisk field for ConocoPhillips in April 2011 (pictures below on the right), and is scheduled to be tested on the Valhall platform by BP in June 2012. The system will not be ready for subsea deployment in the foreseeable future however, as the company still struggle to convince operators of Ziplog's reliability and value impact. Some concerns have been raised with regard to carbon being a brittle material, and the general operational limits for the rod. The tool is included in this thesis as it has the potential to become a step change in intervention technology. It will be interesting to follow the results from the field tests on Valhall over the summer.

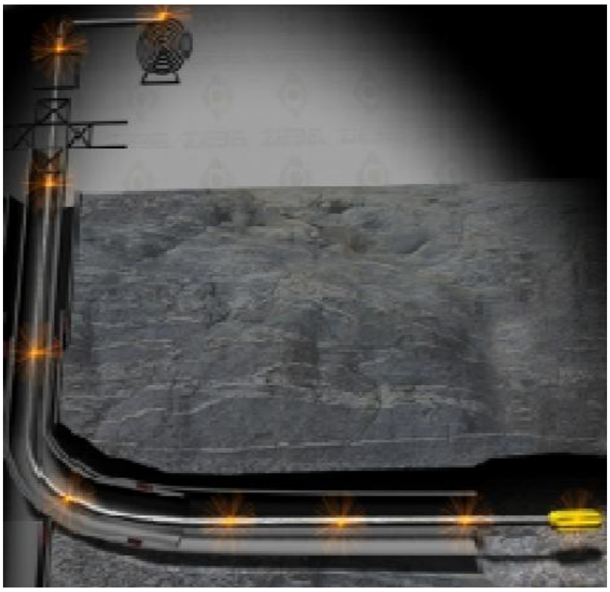


Figure 40: Z-System Stationary Concept [62]

Figure 39: Z-System on Ekofisk [62]

3.8.3 Future Subsea Well Intervention Opportunities and Desires

The future for LWI seems bright and a lot of resources are spent on LWI research by all the major oil companies. The strongest desire is currently to overcome the final challenges related to coiled tubing operations from LWI vessels. This has already been achieved with rigid riser systems, and such a system would also allow high volume pumping. All modern LWI vessels are prepared for CT capability, and the commercialisation breakthrough is felt to be "just around the corner".

Multi-tool seafloor storage could potentially save the industry time and money. This desire is incorporated in the Expro AX-S system. It is obvious that a 10 000 feet capability vs. ~2000 feet of today's WTW will represent a huge leap forward. There have however been raised major concerns with regard to metallurgy when going deeper and especially embrittlement of metals at subsea temperatures and pressures cause failures. Further research into metallurgy and how to cope with increasing water depth has to be sustained.

The operators on the NCS have huge challenges related to Permanent Plug and Abandonment (PP & A) and 2000 wells have to be PP & A on the NCS by 2040 [11]. The vast extent of the coming P&A campaigns that is bound to happen (the PP & A wave is expected from 2015 [11]), and the fact that P&A of wells does not create any revenue, makes it important to perform the numerous P&A operations as cheap as possible. The desire is that monohull vessels will be able to perform larger parts of P&A operations and possibly deliver a total subsea well plug and abandonment operation package. This might be possible by making use of a jack up system to cut tubing in segments and from there be able to hoist and cement. Creative well cross-section plugging methods and materials are expected to enter the market soon. Soon is a relative term, especially in the oil industry where soon either means days or years.

4.0 Learning from History: In depth study of BP Operational Data and Lessons Learnt

4.1 Field Trip to Aberdeen, UK

From February 26 to 1st of March, a field trip to Aberdeen, UK, was arranged to collect lessons learnt and conduct in depth interviews with subsea intervention experts and an experienced well site leader (in charge of the entire specific subsea intervention operation) with numerous LWI operations behind them. The trip proved extremely useful and provided huge amounts of data for the assignment which have been assessed and integrated throughout this thesis.

Figure 41: BP North Sea Headquarters, Aberdeen. 27.02.12-01.03.12 Private Photo, Are Folkestad Kile

4.2 BP Developments in the North Sea

BP has several subsea wells in the North Sea but all of these wells are located on the UK Continental Shelf (UKCS). The Skarv development will comprise the first subsea wells operated by BP Norway. The complete subsea tree population for BP North Sea Region can be found in appendix F.

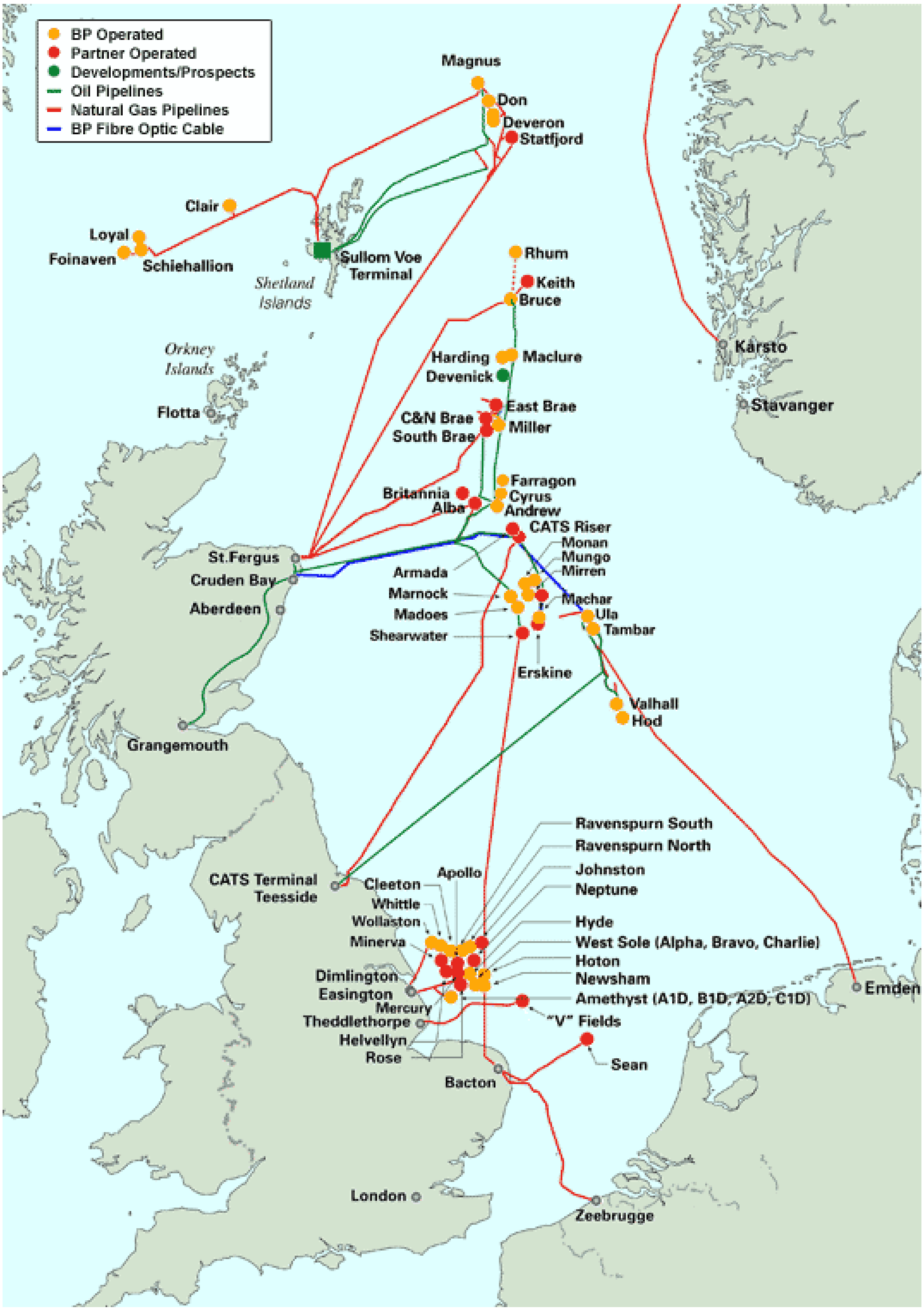


Figure 42: BP Developments in the North Sea [64]

4.3 Rushmore Reviews / OREDA Database

The Rushmore Reviews has just recently started (2011) logging well intervention data and will soon become a very useful database to host operational data and to pick up trends. There is no data qualified and available yet, but for the future the Rushmore Reviews database for well interventions will be a key international experience exchange base for technical issues, problems experienced and time and cost estimations.

OREDA (Offshore Reliability Data) is another project organisation sponsored by eight international oil and gas companies with the main purpose of collecting and sharing reliability data among the companies and act as a forum for subsea equipment and systems [65]. This database is also an important source for reliability data for future risk assessment for subsea well intervention operations. The data in OREDA has not been a source for this thesis.

4.4 BP North Sea Lessons Learnt (2009-2011)

BP UK has extensive experience in LWI operations on the UK shelf and West of Shetland. These operations have generated lessons learnt from unplanned events and incidents. The lessons have not been jointly addressed, cross-referenced and compared until now. There are also positive lessons learnt, but unless they concretely contribute to improved efficiency the thesis will place focus on the unwanted ones. As it is not known which vessel will possibly be used on Skarv, lessons learnt focus will be on general shortcomings that can be used to improve efficiency across different vessels, and summarised to a level with interest for all LWI vessels.

All the BP UK lessons learnt that have been assessed and analysed in this section. This uncovered a need for further risk management focus and will possibly make BP able to avoid or reduce the probability of recurring problems or perhaps incite modifications in routines or practices. The lessons learnt gathered are from the following fields (refer to map in the section 4.2):

- **Don**

The Don field is located in block 211/18a, north-east of Shetland and very close to the NCS border. It was discovered in 1976 and first oil was produced in 1989 overcoming 160m of water depth. There are seven wells at the site, but the oil and water pipelines have been out of service since 2003 and attempts to bullhead have been unsuccessful. There have also been integrity concerns with some of the tree valves. Due to this the field has been shut in since 2003, and a decommissioning project was launched to plug and abandon the field in 2009.

- **Magnus**

The Magnus field is located in block 211/12, at 186 m water depth about 160 km north-east of Shetland and is the Don Field’s neighbor to the north actually making up the northernmost field on the UK Continental Shelf. It was discovered in 1974 [66] and named after the Viking Saint of Orkney. Oil production started in 1983 and has been recovered through 14 deviated platform wells and seven subsea producers [67]. Due to depletion, an enhanced oil recovery (EOR) project was launched in 2003, bringing gas from the fields West of Shetland to the Magnus platform. EOR efforts have assured production from the field throughout 2014, but Magnus is undeniably reaching the end of its productive life after close to 30 years in service.

- **Minerva**

The Minerva field consist of an unmanned platform located in block 47/4b approximately 40 km east of Humberside in England [68]. It receives production from two platform wells, one subsea well and two Apollo (neighboring field) subsea wells, and sends gas to the Easington Catchment Area (ECA). ECA is the focal point for many of the small fields in the area. BP acquired complete control of Minerva and other similar fields from the BG Group in 2008, but agreed to sell the southern North Sea cluster (including fields such as Whittle, Ravenspurn, Hyde, Minerva and many more) to Perenco in a $400 million deal [69]. The deal took place in March 2012 and Minerva is no longer BP operated.

- **Schiehallion**

The Schiehallion oil field is located 175 km West of Shetland, spread over block 204/20 and 204/25 on the Atlantic Margin. After twenty years of effort and over 100 exploration wells the first commercially viable discovery (Foinaven) in the UK sector of the Faroes / Shetland was drilled in 1992 [70]. The Foinaven field discovery led to the find of Schiehallion and Loyal fields. Due to the water depths of 400 m, the Schiehallion field had to be developed with advanced subsea technology and a specially designed FPSO to handle the rough conditions thrown at it by the Atlantic Ocean. Today there are 46 wells in five clusters spread across the seabed. Some wells have horizontal sections of up to 1500 m making well intervention work very challenging.

- **Bruce**

The Bruce oil and gas field is a complex structure of three reservoirs consisting of several separate accumulations. It is located 340 km north-east of Aberdeen bordering blocks 9/8a and 9/9b. The field was discovered in 1974 but did not start production before 1993 [71]. The development includes three platforms which recover hydrocarbons by 20 platform wells and six subsea wells sitting in 121 m of water depth. The field is currently on plateau production.

- **Devenick**

The Devenick field is located in UKCS blocks 9/24a, 9/24b and 9/29a in the northern North Sea approximately 180 km south-east of Shetland and 3 km from the UK/Norway median line [72]. The

Devenick development is a gas condensate reservoir consisting of two subsea wells and a manifold structure at 114 m of water depth tied back to the Marathon operated East Brae facility. The field was discovered in 1983, but development did not start before 2010. The field has an estimated lifespan of 20 years and is expected to come online during summer 2012.

- **Machar and Madoes**

The Machar field is located in block 23/26a about 240 km east of Aberdeen in the central North Sea. It was discovered in 1976 with production starting in summer 1998. Machar is part of the Eastern Through Area Project (ETAP) which has a Central Processing Facility (CPF) that receives hydrocarbons from nine different reservoirs, differing ownership and operatorship. Machar is produced via a subsea tieback to the CPF 36 km away. The field has nine wells and two water injectors. Gas is also routed to Machar to gas lift oil from the depleted reservoir. Madoes is one of the other subsea fields connected to the CPF. It is tied back via a 10” production line, a 6” gas lift line and an umbilical.

4.4.1 Lessons Learnt Grouping

Lessons learnt from these fields have been grouped into broader categories, based on what happened and why. More than 400 lessons learnt reports have been studied in this thesis.

Lessons Learnt Grouping						
Planning / Mobilisation	Rig Up	Operations	Equipment	Personnel	Communication	Other

Figure 43: Lessons Learnt Grouping

Rig Up refers to any rig up and hook up activity on the vessel deck. Any subsea activity such as rigging up WCP on the XMT falls under “Operations” category. The remaining categories should be reasonably self-explanatory.

The background for why the well intervention was carried out will only be mentioned if deemed relevant for learning aspects, otherwise they will be presented individually and “out of operational context” to highlight learning for that specific category largely independent of which operation were underway. The level of recommendations made is where the recommendation is decided to be of value to other RLWI operations, and not 100 % specific to the operation or vessel where the experience occurred.

The following table establishes the foundational background for the next sections. Lessons learnt have been identified, grouped and counted to provide an overview over which phases of the operation are more critical than others with regard to negative experience and lessons learnt.

Field	Year	Vessel	Lessons Learnt Grouping							
			Planning / Mobilisation	Rig Up	Operations	Equipment	Personnel	Communication	Other	Sum
Don										
	2009	Seawell	17	7	8	28	3	2	11	76
	2010	Seawell	12	0	3	10	1	2	3	31
	2011	Well Enhancer	19	1	10	5	0	2	1	38
	Don Total		48	8	21	43	4	6	15	145
	In %		33,1 %	5,5 %	14,5 %	29,7 %	2,8 %	4,1 %	10,3 %	100,0 %
Magnus										
	2011	Well Enhancer	2	0	3	6	0	1	0	12
	In %		16,7 %	0,0 %	25,0 %	50,0 %	0,0 %	8,3 %	0,0 %	100,0 %
Minerva										
	2010	Seawell	1	2	6	7	1	0	1	18
	In %		5,6 %	11,1 %	33,3 %	38,9 %	5,6 %	0,0 %	5,6 %	100,0 %
Schiehallion										
	2009	Island Constructor	29	1	18	53	3	9	1	114
	In %		25,4 %	0,9 %	15,8 %	46,5 %	2,6 %	7,9 %	0,9 %	100,0 %
Bruce										
	2010	Island Constructor	13	1	15	5	5	1	1	41
	In %		31,7 %	2,4 %	36,6 %	12,2 %	12,2 %	2,4 %	2,4 %	100,0 %
Devenick										
	2011	Island Constructor	19	0	23	7	1	2	6	58
	In %		32,8 %	0,0 %	39,7 %	12,1 %	1,7 %	3,4 %	10,3 %	100,0 %
Machar										
	2010	Island Constructor	8	2	13	14	5	2	4	48
	In %		16,7 %	4,2 %	27,1 %	29,2 %	10,4 %	4,2 %	8,3 %	100,0 %
Total for all lessons learnt			120	14	99	135	19	21	28	436
In %			27,5 %	3,2 %	22,7 %	31,0 %	4,4 %	4,8 %	6,4 %	100,0 %

Figure 44: Lessons Learnt from BP LWI Operations in the North Sea 2009-2011

There are 120 lessons learnt from “planning / mobilisation” category and 135 for “Equipment”. In total there are 436 lessons captured by BP UK for the subsea intervention operations the last three years (2009-2011). All these lessons have been analysed and the most important recurrences are highlighted in the following sections. Some “end of well” reports have also been analysed in this thesis and taken into account. These reports sum up how the operation went and what could have been done differently.

4.4.2 Planning and Mobilisation Commonalities

Findings	
Recurring challenge	**Recommendation**
Various procedures have too many Management of Change (MoC) documents making the operation logic hard to follow. Incorrect information or missing documents and incorrect dimensional drawings.	Send ONLY ONE dedicated programme procedure out with the vessel. Decide which procedure to use or make up a combination in one document. The practice of indicating where to find the next step and in which procedure is too cumbersome and not satisfactory. Improve clarity in procedures and update procedures from operation in order to contain all relevant MoCs according to end-of-well reports and subsequent post-operation assessments. Quality check and verify all documents and drawings sent offshore, important documents may need signatures to flag their criticality status (e.g. barrier drawings).
Contractor not trained in other contractor's equipment and handling of such (i.e. SLB supervisor not trained to handle Petrowell plugs and packers).	The best alternative for clear accountability is to send out a representative for each company that has specialised equipment on the vessel. Prepare and pre-teach contractors that are going onboard for the operation in all equipment that is planned on being used and contingency equipment.

Lack of spares (contingencies, re-dress kits).	Identify spare requirement according to risk assessments prior to mobilisation. Contractors to provide critical spares review list of all contractor equipment based on reliability experience for BP assessment.

4.4.3 Rig Up Commonalities

Findings	
Recurring challenge	**Recommendation**
Markings on lines, hoses and outlets.	Provide clear markings on lines and outlets. To be part of vessel and system pre-operation check and inspections. Contractual requirement – HSE impact.
Interface clashes.	Contractual obligation for service companies to ensure interface match to planned application. It is necessary to make sure that various equipment from different suppliers work together before leaving port.

4.4.4 Operations Commonalities

Findings	
Recurring challenge	**Recommendation**
Various issues when "Between-well-testing". This activity is a time thief!	Be alert, optimise and plan thoroughly what is to be done and what needs to be tested. Jump wells if possible to avoid between-well-testing.
Line management. Lines become damaged under the ship's hull and entangle with other equipment passed through the moonpool.	Re-design all relevant sharp edges in moon pool and fit rollers to hatches. Use umbilical clamps if appropriate. Camera in the moonpool area will aid in deployment and equipment surveillance.
Interface clashes.	Interface compatibility has to be verified also after small modifications and adjustments.
Tree valve status and operability.	Implement a status board for tree valves during operations. Verify that potentially needed tree valves may be operated.

4.4.5 Equipment Commonalities

Findings	
Recurring challenge	**Recommendation**
Difficulties for ROV handling dummy stabs in ROV panel on subsea trees	Re-design dummy stabs to eliminate problem. Keep diver redundancy when handling of dummy stabs can be a potential problem.
Various issues with the Umbilical Termination Head and Well Control Package.	The equipment is mentioned due to creating more trouble time in relation to the other equipment. No specific recommendation provided apart from maintaining focus when operating this critical equipment.
Connection and locking difficulties with the Tree Running Tool and Tree Cap Running Tool	Test onshore prior to deploying the running tools offshore. Special emphasis on avoiding interface clashes.

4.4.6 Personnel Commonalities

Findings	
Recurring challenge	**Recommendation**
Ensure that the combined personnel on board have all relevant certifications. There have i.e. been conducted operations with no personnel certified for backloading of radioactive LSA when this could have been needed.	Make sure contracts cover the needed qualifications and certifications for relevant services, and make contractor responsible for ensuring compliance.
No “Meet and Greet” (M&G) for oncoming personnel.	Be strict on necessity to perform “M&G” for all oncoming personnel. Provide update on operations, any recent incidents and coming focus areas and risks.

4.4.7 Communication Commonalities

Findings	
Recurring challenge	**Recommendation**
Slow or non-responsive BP online systems.	Upgrade net communication speed. Review and establish contingency solutions in case of communication system failures.
System and Hard Drive Access.	Create one distinct folder for each well or operation and give all participants full access to this specific folder. Require every participant to include any needed documentation in this specific folder. This will guarantee everyone knows where to locate up to date and correct information. Simultaneously this will ensure that 3^{rd} parties do not gain access to other BP sensitive material. BP onshore WIE (Well Intervention Engineer) and only one person WSL (Well Site Leader) offshore able to update this folder. The WSL checklist made by Jamie Lundie (appendix G) and the WIOG could be a good starting point in ensuring all relevant information is included in the folder. This list should be included in governing documents guideline section.

4.4.8 Miscellaneous

Findings	
Recurring challenge	**Recommendation**
Unknown fluid weights and fluid paths in annuli when punching tubing.	Proper risk assessment, and preparation for annuli over- or underbalance. MEG coloring has shown to be advantageous to locate leaks, and needs to be assessed as a contingency material.
Varying participation with regards to safety reporting.	Designate and rotate different members of the team to lead TBT's (Tool-Box-Talks, final safety preparation before operation. A kind of safe job analysis)

4.4.9 Lessons Learnt Summary Comments

It is obvious (not too shocking) that many of the bad experience and lessons learnt incidents could have been avoided if the troubled operations were planned and risk assessed better. Many lessons learnt from other categories than “Planning / Mobilisation” could have been eluded if sufficient planning and risk management had been implemented to predict and mitigate possible operational problems and clashes.

There are numerous examples of hardware interface clashes and this should be highlighted as one of the largest reasons for downtime. An example from Island Constructor operating on the Devenick field in 2011 shows that interface clashes can create additional problems: “unable to land off Cameron Tree Running Tool on XMT due to interface issues between the hydraulic couplers. Various attempts to land the TRT anyway lead to wear on equipment and 3 coupler shrouds came free.” Accountability for interfaces and typical risk focus towards interfaces will help clarify this issue and to lower the probability for occurrence as well.

There are also numerous cases of missing procedures for different known and contingency operational needs. One lesson learnt e.g. reported “no procedure for removing bridging plate on XMT and installing Tree running tool umbilical flying plate”. Many similar lessons are reported, and the overall challenge is to gain full control and coverage for all equipment and operations. Procedural interfaces should be checked as well.

It is noted that several lessons learnt with regard to handling equipment through the moonpool calls for procedural update taking into account lessons learnt from all vessels. Lessons learnt only comments the operational problem with regard to this particular problem, not solutions. The problems are mainly captured as hard edges, guiding frame and splash zone problems. No vessel will probably be called back to base for re-welding, although the winter months could potentially be used to accommodate vessel improvements.

The lessons learnt amongst the operations and equipment categories comingle to a certain degree. This has contributed to lessons being placed in the wrong category, and some of the equipment lessons could might as well have been placed within the operations category. An example here is the dummy stab lessons from section 4.4.4. There is a problem operating it, but the main challenge lies in its design. In summary it is therefore the equipment that is the problem, thus it is placed in the equipment category. Looking for commonalities in the “Equipment” category is still a challenge. Root causes and which equipment is affected are very different, and it is difficult to identify one single action to combat equipment failures. Recommendations are therefore routed to the equipment category (UTH, TRT and WCP) with the highest amount of lessons learnt, to impose strict focus when handling this equipment. Not all equipment failures are carried to the “investigation level”, and real root causes may still be uncertain.

4.5 Case assessment: Investigation of the unplanned shearing of braided line on Madoes Field

Another arena for organisational learning and risk awareness is the study of investigation reports.

This recent incident is elaborated to illustrate how lessons learnt are obtained and how the operation could have been done differently. The incident took place on the Madoes field (block 22/23b-A1) in November 2011 during operations with the Well Enhancer. Section 4.5 is based on reference [73].

Background

The Madoes field has suffered a significant decline in production performance since 2009, ranging up towards 50 % deterioration. The three most probable causes for this decline have been narrowed down to calcium carbonate scale, gas blocking around the wells or sand (or other fine particles). As a result of the declining production, a well intervention was planned using the LWI vessel Well Enhancer in October 2011. The objectives were to:

Primary Objectives
Confirm well access and the nature of any restriction
Carry out a saturation log to determine the presence of free gas in formation and the behind pipe saturations
Carry out a multi rate PLT to determine any free gas, water inlet depths, rate dependent flow regime, areas of zero production and pressure build up
Secondary Objectives
Acquire fluids sample (hydrocarbon) to determine asphaltene tendency and bubble point
Caliper the completion to assess the integrity of the well
Remove scale restriction in tubing if present to regain full bore access

The Well Enhancer was mobilised for Madoes to deliver the above objectives and arrived on location on the 2nd of November 2011. DP trials were performed satisfactory and permission to enter the 500 m zone was given. The ROV was deployed to conduct the routine “As Found” inspection and clean the XMT. Once established on location, the debris cap was removed, the SIL deployed and plugs removed.

The first planned run into the well was to recover the flow watcher venturi from 2530 m below rotary table (BRT) on 7/32” braided line to allow access to the lower completion. When the toolstring was run in hole (RIH) a restriction was encountered at 166 m BRT. It was decided to continue with the planned programme and run a 40 arm caliper, X-Y caliper and tractor to measure the restriction.

This second run was performed on 11/32” tri-core cable to be able to tractor down the toolstring for the planned production logging. The toolstring weight in the lubricator was 500 lbs. Again the toolstring was held up at the same depth of 166 m BRT. Two logging passes were made from 166 m BRT to 112 m BRT to identify possible integrity issues above the holdup depth. It was decided to retrieve the toolstring, so the cable speed was reduced to 6m/min to accommodate pulling of the string into the toolcatcher.

The ROV was monitoring the grease head and waiting for the toolstring to be caught when a release of gas was observed. Simultaneously, a drop off in tension and loss of communication with the toolstring from the wireline unit was confirmed. Due to the gas leak, additional grease pressure was applied to the grease head, but realising that there was no cable in the grease head, the upper and dual pack-off seals were activated. The release of gas stopped as the ball check valve seated and sealed.

At this point it was realised that the weak point had been pulled. On recovery of the grease head it was observed that the toolstring was not in the toolcatcher, signifying that the toolcatcher had failed to catch the toolstring. Slickline was rigged up and a 4” lead impression block was RIH and this gave a clear indication of the fish neck. Although fishing is seldom an option for LWI vessels due to the inability to extend the length of the subsea lubricator, this could be attempted in this case by utilising the safety head and Lower Test Valve (LTV) as barriers to provide sufficient lubricator length.

The first attempt to fish the toolstring managed to latch on to the fish and bring it up to the toolcatcher, but the fish released from the pulling tool and dropped to the safety head. The slickline toolstring was recovered and a new run prepared. The second run latched and recovered the fish back to the vessel, but on inspection of the toolstring the X-Y caliper and bow spring centraliser was missing and left downhole. The 40 arm caliper was also badly damaged with 35 fingers lost downhole. Further attempts to retrieve the remaining fish were unsuccessful. It was decided to push the fish down to the original hold up depth and suspend operations. The protection sleeve was recovered and the plugs set and pressure tested. The cable and cablehead were quarantined for onshore investigation. The well remains shut in with a loss of about 1500 BOPD.

Investigation

Company X provided BP with the 11/32” tri-core cable and cablehead that failed. The cablehead was delivered with an unconventional fishing neck, so company X approached company Y who manufactured a new 1.375” fishing neck and made it up to the cablehead. The weak point of the cablehead was made up with 6 outer armors and 3 inner armors with a weak point rating of 2652 lbs. There was no concern with the condition of the tri-core cable as it was new. With both cableheads returned from the Madoes intervention, the company X engineer responsible for building the weak point was requested to re-construct the work using the back-up cablehead.

Figure 45: Fish re-constructed onshore

This was sent for pull testing, where the weak point prematurely failed at 1720 lbs.

Due to an interface issue between the cablehead and the company Y fishing neck, it failed to compress the thrust washer to the tear drop socket. Without this compression it is proved to pull the weak point prematurely as test results showed. The engineer responsible for making up the rope socket (cablehead) was unfamiliar with the equipment and did not pick up on this. Company X allegedly planned to carry out a pull test but did not.

The other failure mode in this incident is the failure of the toolcatcher to catch the toolstring. The set-up of the toolcatcher is such that the fish neck will be caught automatically and released only by applying hydraulic pressure to release the collets holding the string in the catcher. The toolcatcher was dressed for a 1.375” fishing neck, and checks carried out both onshore and on the vessel confirmed compatibility.

After pulling the toolcatcher, no mechanical fault was found. The only time the hydraulic pressure had been applied was an hour prior to pulling the weak point. 3100 psi was applied to release the toolstring from the toolcatcher on completion of pressure tests and in preparation for RIH. When the weak point was pulled an hour later, the toolcatcher was or at least should have been in the catch position. Why the toolstring was dropped remains a mystery.

As supplementary information it is noted that the cable speed coming into the catcher was 6m/min. The manufacturer was unable to supply any information on max cable speed to ensure that the toolcatcher operates as designed.

There were three alarm systems set. These included “Differential Tension Alarm” set at 2970 lbs, “Surface Tension Alarm” set at 2400 lbs and an “Over Tension Alarm” set at 3000 lbs. None of these alarm systems were activated during the incident.

Reflection

This situation was primarily caused by interface issues and faulty fabrication of the string with a lower strength weak point then advertised. After the weak point had been pulled, any counter-action to avoid the situation would be too late. The faulty fabrication of the wire is difficult to safeguard against once operation is underway. Since investigation has uncovered that the wire was not tested before shipped offshore, the problem could and should have been uncovered before the wire was allowed to run in hole. Thinking that “the wire is brand new” contributed to the limp attitude towards the wire as crews are used to fatigue issues causing problems and rarely experience faulty new equipment. Operators do have the possibility of testing equipment before sending it offshore, but this would be impractical and costly due to all the equipment that is sent offshore every day. It is natural that the supplier tests its equipment; operators will stop contracting suppliers with bad track records. The operators should have procedures making sure that everything that goes downhole is tested with appropriate test verification attached to the handover from supplier to operator.

Root causes:

- Failure to manage interface issues when introducing new equipment.
- Failure of Assurance process for new equipment, e.g. failure to carry out pull tests on cable and cablehead to confirm weak point rating.
- Inadequate procedures (existing procedures do not mention setting alarm systems when pulling out of hole (POOH), and no recommended speed when coming into the toolcatcher.
- All alarms were incorrectly set for toolcatcher operation
- Not maintaining a “Z chart” for depth control, and no clear procedure for selecting toolstring zero point for subsea interventions

Important lessons learnt and recommendations:

Findings	
Lesson	**Recommendation**
Testing of tools and equipment not performed by supplier	Ensure documentation of confirmed tests is attached when equipment delivered. Highlight to all suppliers that delivering untested equipment is unacceptable and can have consequences for future co-operation.
Clarity on weak point and setting alarms	Include required weak point rating in BP programme and appurtenant values for alarm setting.
Confusion with regard to depth control	Introduce a “Z chart” (i.e. the one in appendix K) including check sheets to maintain depth control.

4.6 Analysis of Operational Data

Operational data is a good supplement to lessons learnt when analysing past operations. Usually a NPT event will lead to a lesson due to the generally unwanted and unplanned nature of NPT. The operational data is comprised of all BP North Sea interventions for the last three years (2009-2011). The data has been collected in an excel sheet and is taken from BPs internal operational reporting system. There has not been any operation yet in 2012 - the Island Constructor will head for the seas West of Shetland in June 2012. All operations assessed have been performed on the UKCS.

The amount of data is massive.

The Island Constructor is the only vessel that has been used all three years. All data from these years have been obtained and the Island Constructor data represents the most complete dataset. The data from all three vessels have been examined, but the data for the Well Enhancer and Seawell has been found to be incomplete. Analysing incomplete data could lead to inaccurate or even wrong conclusions being made. Therefore, only Island Constructor data will be presented here. To extract full learning from the two other datasets, the complete sets need to be obtained.

Due to the strong connection between NPT and lessons learnt, NPT has been the focus for the operational data analysis. The NPT statistics for the Island Constructor have been extracted:

2009	Operational Uptime	RREP	UFAL	SFAL	DFAL	WSEQ	WOW	CURR	SUPP	PERS	EQSC	HMN	PROD	NPT	Total Operation
Hours	1559,76	35	148,5	18,75	61,5	270,25	48,5	1	0	0	2	1,83	6	593,33	2153,09
% of Total	72,44 %	1,63 %	6,90 %	0,87 %	2,86 %	12,55 %	2,25 %	0,05 %	0,00 %	0,00 %	0,09 %	0,08 %	0,28 %	27,56 %	100,00 %

2010	Operational Uptime	RREP	UFAL	SFAL	DFAL	WSEQ	WOW	CURR	SUPP	PERS	EQSC	HMN	PROD	NPT	Total Operation
Hours	1158,25	0	1,5	4,5	0	0	1,5	4	1,75	10	0	0	8,5	31,75	1190
% of Total	97,33 %	0,00 %	0,13 %	0,38 %	0,00 %	0,00 %	0,13 %	0,34 %	0,15 %	0,84 %	0,00 %	0,00 %	0,71 %	2,67 %	100 %

2011	Operational Uptime	RREP	UFAL	SFAL	DFAL	WSEQ	WOW	CURR	SUPP	PERS	EQSC	HMN	PROD	NPT	Total operational time
Hours	1262,12	0	44,5	118	72,5	44	43,75	7	0	0	3,5	1	0	334,25	1596,37
% of Total	79,06 %	0,00 %	2,79 %	7,39 %	4,54 %	2,76 %	2,74 %	0,44 %	0,00 %	0,00 %	0,22 %	0,06 %	0,00 %	20,94 %	100,00 %

Figure 46: NPT Distribution for the Island Constructor, 2009-2011

RREP	UFAL	SFAL	DFAL	WSEQ	WOW
Rig Repairs	Subsea Equipment Failure	Surface Equipment Failure	Downhole Failures	Well Service Equipment	Wait on Weather
CURR	SUPP	PERS	EQSC	HMN	PROD
Current / Tide	Supplies	Personnel	Equipment Service Contractor	Human Error	Production

Figure 47: Nomenclature for Figure 45

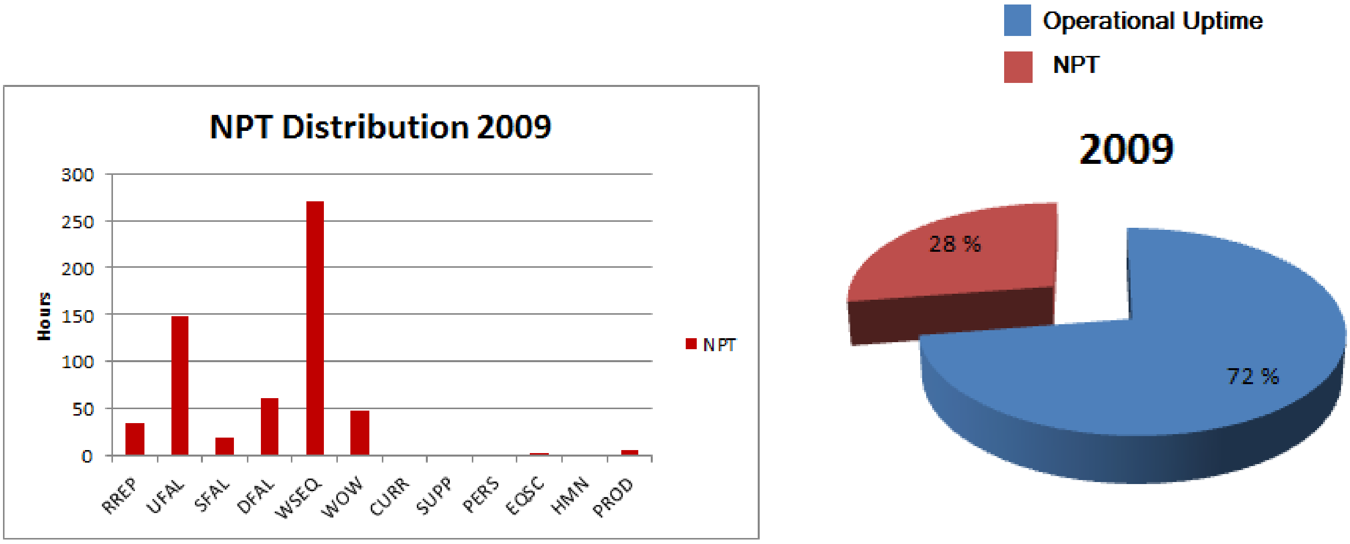


Figure 48: NPT Graphical Distribution for the Island Constructor 2009

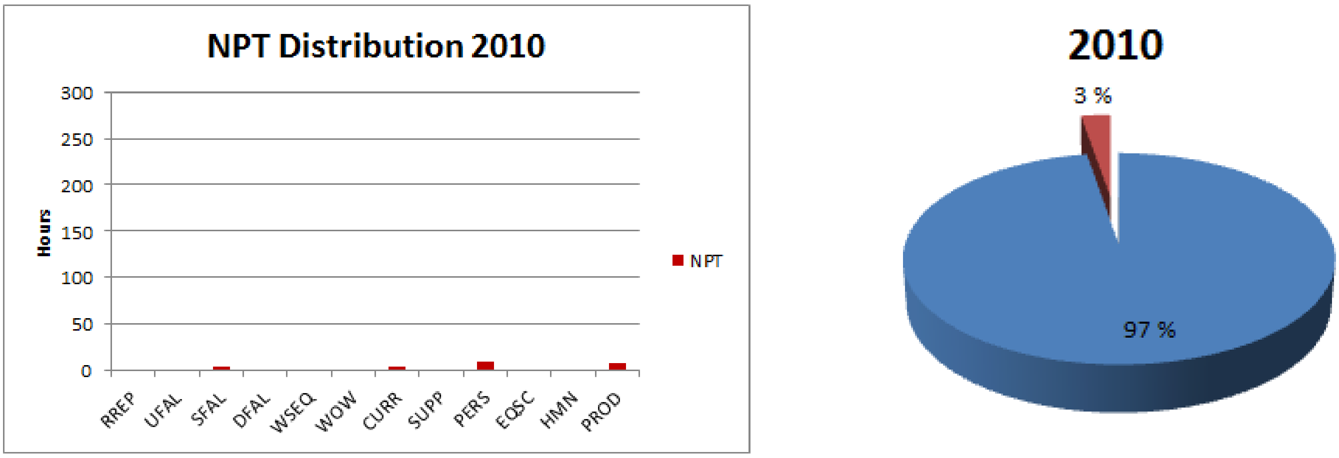


Figure 49: NPT Graphical Distribution for the Island Constructor 2010

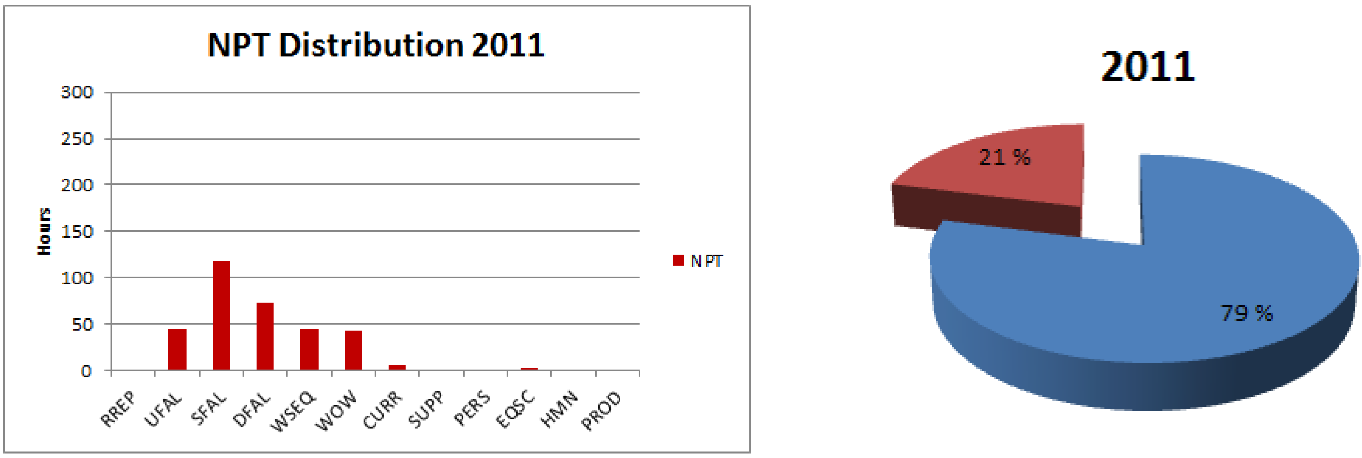


Figure 50: NPT Graphical Distribution for the Island Constructor 2011

From a NPT viewpoint it is clear that 2010 was the best operational year by far. The statistics show there was very little time (6 hours) lost to equipment failure, while equipment failure caused 439.5 and 210 hours of NPT in 2009 and 2011 respectively. In addition to this, the 2010 campaign only had to suspend operations for 1.5 hours due to bad weather while both other years had to wait substantially longer (48.5 and 43.75). There is no difference in scope of work for these years capable of explaining why 2010 was as successful.

The statistics show how important equipment reliability and workability is for NPT avoidance. Equipment failures have been the largest contributor to downtime the last three years, causing 74 % of NPT in 2009, 19 % in 2010 and 63 % in 2011.

Apart from equipment related downtime, weather limitation also represents a fair fraction of light well intervention related NPT. Weather, currents and significant wave height will persist as a challenge in the North Sea. The only way to combat the NPT associated with Mother Nature is developing new technology and improve or expand on compensation technology solutions.

Climate change is a slow process, and so far the important weather factors causing trouble for well interventions are fairly stable from year to year, with some variations (as 2010 statistics actually show). Wind, current, waves, rain, snow and ice of course vary from day to day, month to month, but over several years the totality is a stable risk factor with a known expectancy.

The new international Rushmore Reviews Well Intervention Review is expected to bring improved standardisation in reporting and analysis for the future, as it already has standardised drilling, completion and plug and abandonment reporting. When this 4th database is in operation, systems providers all over the world may improve their well intervention logistics as well. The data from this database could be used to study NPT in intervention operations even further.

4.7 Success Stories

Although not analysed in detail, it is important to repeat successes in addition to avoiding previously incurred unwanted incidents. In uncovering how LWI operations should be performed, it can be helpful to have a look at a couple of success stories to try to understand and identify why these were successful operations. Viewing this in combination with the lessons learnt can unveil new information. Two success stories have been selected based on LWI operational criteria, from Foinaven (West of Shetland) and the Ninian oil export line (exporting Magnus hydrocarbons).

4.7.1 Foinaven – Subsea XMT leak

An anomaly associated with well P211 on the Foinaven field was investigated by Subsea Viking (supply vessel) in April 2009 [74]. On arrival, a leak was visible at the XMT confirming that well integrity had been lost. The well was immediately shut in to stop the leak. The loss of integrity was decided to be due to a leaking tree cap, and a plan to change out the cap was initiated. The Island Constructor was due to commence operations for BP West of Shetland during summer 2009, and the repair was slotted in prior to this – making the Foinaven tree cap repair Island Constructors first job for the company. The short timescale created challenges related to approvals, authorisation, logistics, planning, notification and mobilisation. There were also several technical challenges for the company since this would be BPs virgin operation using a mono-hull DP vessel West of Shetland. In spite of this the well was back online five days after mobilisation of the Island Constructor after having met all intervention objectives. The keys to the successful delivery have been attributed to:

- The planning work was clearly prioritised to focus on key issues, what you focus on will be done properly.
- Active co-operation and responsibility assumed from all vendors
- Full support across all BP functions in order to bring well back on stream

These may seem as basic expectations, but even basics during normal operations need to be focused on and given attention in order for them to be completed successfully.

4.7.2 Magnus – Export pipeline subsea isolation valve failure

In September 2009 the BP team was informed that the Ninian 36" main oil export line (carrying Magnus production) was shut down due to a probable fault with the subsea isolation valve (SSIV) [75]. It was quickly established that a Dive Support Vessel (DSV) would be required for any diagnostic and intervention work. The Seawell was on hire (at that time working on the Don decommissioning project) and the vessel was requested to perform the intervention. The next day, all procedures were written and issued, spare hydraulic hoses loaded, a Hazard Investigation and Risk Assessment (HIRA) completed and the Seawell departed for the site. Within 40 minutes of arrival, a failed hose fitting was identified and isolation procedures were initiated to allow divers to access the fault. In the meantime a General Visual Inspection (GVI) that had been planned for later that year was performed. The divers were deployed and the failed hose changed out. The system was re-commissioned and the ROV checked and confirmed that the 36" SSIV was operational. The keys to delivery have been attributed to:

- Vessel availability with assurance completed and ready to mobilise within a very short timescale
- Rapid response, but with proper risk management in place
- Full support across BP functions, urgency often provide high visibility
- Key equipment already loaded onboard vessel (downlines, hydraulic pack and hydraulic fluid)
- Good communication and coordination between platform and vessel

It can be seen that success stories refer to a higher degree of "general wording" than lessons learnt. General wording gives fewer clues to specific elements, and is regarded as less valuable for concrete planning on an engineering level. Proper risk management will always be a good contributor to success.

4.8 Organisational Learning

It is fairly common that large companies have a hard time actually teaching themselves the lessons learnt from previous operations. Even though the operational data and lessons learnt are recorded and properly filed, the hectic nature of the oil industry often requires the engineers to immediately focus on the new projects before they are able to properly assess and go through the previous job. Often the learning and recommendation is properly done by the team that had the experience, but the “listening parties” may be missing, and high activity levels may make it hard to properly assess all available learning in the system.

Individuals and specific teams learn by doing similar operations in series; however this is not necessarily the case for organisations. Organisations consist of many relatively independent teams, transgressing national borders and working under different management systems and learning structures. In addition to this, the operations may be spread over considerable time making way for the “forgetting factor”.

A group has been established at BP to make sure the organisation learns from previous incidents. The group is multi-disciplinary and its main function is to make sure that learning from incidents is reviewed and passed on the relevant fields and procedures for future execution.

“Most incidents that have occurred in BP Norway have already taken place elsewhere in the industry [76]”. The group takes a closer look at lessons learnt and distributes actions to individuals or distributes it for information depending on where it may be needed and the criticality of learning. Every two months the lessons learnt are reviewed and a selection of these will after consideration be sent on to implement specific changes or checks, to be included in safety meetings, or be assessed for instruction or directive updates.

Such groups (especially if not permanent groups) need to build permanent work processes to ensure important learning is spread company-wide as efficiently as possible. Lots of structures and systems can make this possible in today’s electronic sharing age, but it is vital that the process is performed in a consistently managed manner.

The precaution against including every learning in the procedures or in the management system is that when a rule oriented regime is established and built, there is less available elbowroom to handle the unexpected. In order to solve this challenge operations engineers need to be trained in proper handling of the unexpected, proper risk assessments of any late planning and operational changes, and given enough operational experience to get a feel of “mastering the operations”.

Organisational learning is an important motivation for this thesis, where part of the intention is to transfer subsea well intervention knowledge from UKCS to Norway.

4.9 Lessons Learnt and Operational Data Summary

From the table in section 4.4 it can immediately be observed that the groups “Planning / Mobilisation”, “Operation” and “Equipment” represent the vast majority of lessons learnt. Combined these three constitutes 81.2% of the total lessons learnt archive for the 2009-2011 period.

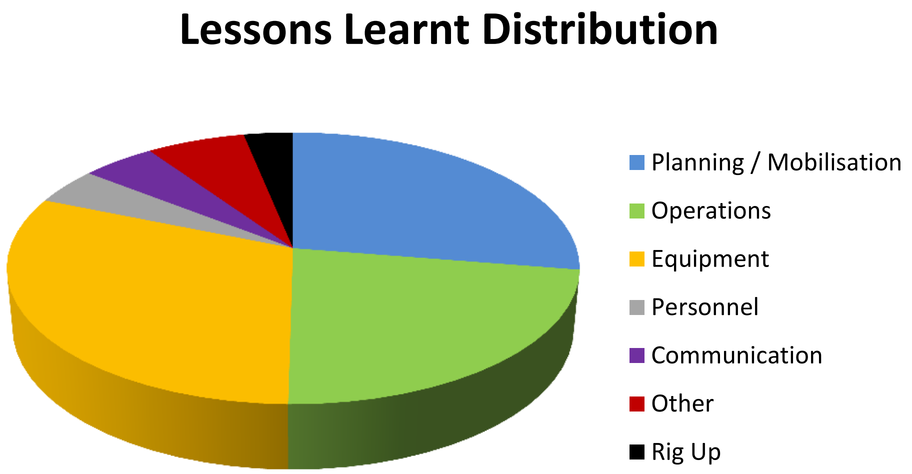


Figure 51: Lessons Learnt Distribution

The statistical analysis have shown that equipment failure (both surface and subsea) contribute significantly to NPT. Lessons learnt have uncovered interface clashes as one of the main reasons for time spent waiting while modifying equipment or air freighting new equipment out to the vessel (lack of spares has also been found as an important improvement arena). It is necessary to increase focus on interface clashes to reduce its influence on operational downtime. Lessons learnt shows that even small modifications have led to downtime. The equipment obviously has to be interface verified before mobilisation, but also when any (even minor) modification is made.

The recurring lessons learnt show that procedures (either too many or non at all) is an area that needs a thorough clean-up. When multiple procedures exist, this should be blended into one “governing document” for a specific well intervention operation. It would also be a good idea to go through all planned procedures to make sure all operational aspects are covered. This issue is closely connected to communication issues, where different parties engaged in the operation sometimes do not have access to operation critical information usually because the information has not been made available for the operation and the need for this information has not been uncovered prior to mobilisation. The investigation report also shows that necessary documentation is not always secured (referring to the equipment not being tested, thus not satisfactorally documented).

The recurring lessons also shows the need to address the more fundamental challenge of continuous organisational learning.

5.0 Risk Management of Light Well Interventions

A week-long ISO accredited ISO Risk Manager Certification course was attended in January 2012 in preparation for proper handling of this section of the thesis [77].

Risk is most often defined as a relation between probability and consequence or more specifically a relation between probability and impact of changes to the planned or intended outcome. There is a close relationship between risk management and lessons learnt, but in order for proactive risk management to be an effective tool against unwanted downtime, risk has to be managed systematically before the (non-wanted) lessons learnt are accumulated. A risk register needs to be used in practice by the operations leader before and during operations (when making changes). Having a better understanding of all the risks involved in a project will facilitate improved decision-making, operations and HSE results.

Large investments, tight time schedules and the introduction of new technology under unproven conditions results in higher risk exposure. It is essential to understand the various uncertainties associated with an operation and accept full accountability. The engineering mindset is often too optimistic and focused on "knowing" how ideas will work out in reality. Engineers should admit that the world is uncertain, and learn from geophysicists and geologists who are more used to incorporate uncertainties in their work.

The ISO 31000:2009 "Risk Management – Principles and guidelines" standard provides a framework to ensure that all reasonable aspects of risk management are incorporated in risk assessments. The operational focus of this thesis leads the attention to the risk management process. As we see from figure 52, a risk assessment process consists of establishing the context, risk identification, risk analysis, risk evaluation and risk treatment. The theoretical process is further elaborated in appendix H, and a more practical well intervention approach is described in this thesis text.

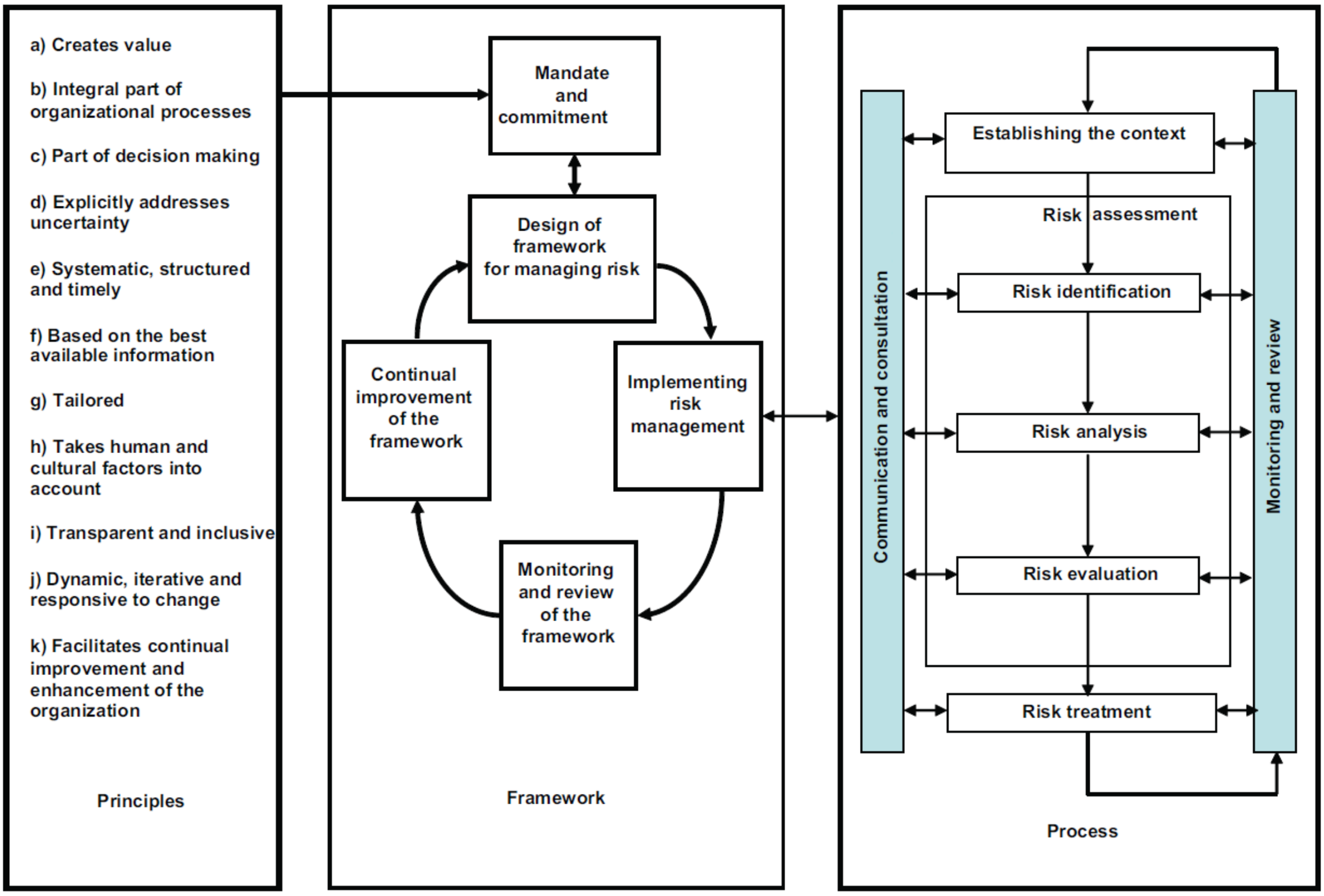


Figure 52: Principles, Framework and Process of ISO Risk Management [78]

The process should have management focus and be an integrated part of the management strategy in general, incorporated in company culture, practices and tailored to business processes like i.e. well interventions. It is crucial that risk focus is clearly communicated from the leadership team.
The use of risk management techniques can help assure that objectives are met, and uncertainties managed better through the entire project. It is important to identify the entire risk picture and the pre-requisites that define the risk assessments' validity.

A complete risk assessment will not be performed in this section. Focus will be on a proactive and practical risk management structure for RLWIs and on how the risk tolerance matrix and risk register can be used to cater for and act upon lessons learnt in order to see the holistic perspective and the importance of details. Establishment of a subsea well intervention risk assessment kick-off template will be the single most important contribution from chapter 5.

An overview of the most relevant risk assessments that need to be in place, known and with connections understood for any subsea well intervention is depicted in the figure 53. More often than not, the complete set of analysis levels is not as active in the involved peoples' minds as it should be. It is equally important to know the context for the various analyses done to ensure validity for the job at hand. Sometimes (slowly) evolving and new technology come into breach with the basis for (particularly vessel and equipment) risk assessments, sometimes the job itself is similar to the last job, but the context critically changed. These are extremely important issues to evaluate for each and every job. Sometimes the well intervention engineer assumes that the drilling and completion engineers have properly prepared for blowout contingencies, which is not always true. A good rule of thumb is to remember that "to assume is to make an ass of u and me, ass-u-me". It is critical to communicate and make sure!

"It is likely that something unlikely will occur" – Aristotle

Figure 53: Operational Risk and Context Totality [5, modified]

5.1 Common Misconceptions

Before getting to the practical risk management, some common misconceptions have to be addressed.

5.1.1 Positive Risk

Risk assessment teams tend to focus on negative risk, but there are also upsides (positive risk) to a project and the positive risk (often called opportunities) is usually the reason why we initiate different projects. When performing a complete risk assessment, sometimes new opportunities are found while trying to mitigate negative risk as well.

5.1.2 Human Error

Many conditions are blamed on human error due to:

- Misjudgment
- Misunderstood information
- Stress
- Confusion
- Lack of knowledge
- Lack of focus
- Complacency

However, these conditions are normally not caused by human error. They are weaknesses with the system or management work processes and are merely exposed by wrong actions. There are always underlying causes that lead to undesired incidents [79]:

- Absent analysis of potentially dangerous situations
- Lacking decision rules for dangerous situations
- Inadequate training in handling the situations
- No testing of safety vulnerable personnel's ability to cope with stress
- Lacking motivation and understanding of the functions' importance
- Pressure from superiors and environment for efficiency

In most incidents the "human factor" is anchored in the company's culture, attitudes, procedures and work processes. There is no such thing as human error alone. That claim might lead one to think that if there is no such thing; artificial intelligence could be programmed to imitate a human being exactly. This is however not applicable due to the irrational nature of humans.

5.1.3 Recordable Injury Rate

For many years the petroleum industry has used the recordable injury rate as a sign of overall safety on different facilities. This is a gross misjudgment.

The fundamental practice of injury rate as an indicator of overall workplace safety has been discredited, since it mainly captures minor accidents such as sprained wrists and ignores the risks that cause major disasters, such as potentially lethal gas leaks [80]. The minor incidents that show up in injury rates are mainly the result of lapses in personal safety, while accidents that cause multiple deaths are usually the result of (several) process safety flaws such as unsafe or outdated equipment and procedures, inadequate training of personnel or lacking risk management.

5.2 Risk Tolerance Matrix

Different risks are identified and recorded in the activity's risk register. Each risk in the register is evaluated to determine if the risk can be tolerated or not. Whether it can be tolerated or not is usually decided by making use of the risk tolerance matrix. An evaluation will decide if approval can be given, or if risk has to be further mitigated as far as reasonably possible before residual risk is re-evaluated and approved if within tolerance criteria. We can protect against some kinds of risk, others we accept and there is risk we cannot predict based on available data, so-called "black swans". It is common to divide risk into three groups:

- Non-acceptable risk
- Unwanted but tolerable risk
- Negligible risk

BP Norway currently uses a table as their risk tolerance matrix for dry tree well intervention programmes (appendix B). The table below is from BP Group Defined Practice *GDP 3.1-0001*.

	Likelihood of Risk Event							
	1	2	3	4	5	6	7	8
Severity Level	A similar event has not yet occurred in our industry and would only be a remote possibility	A similar event has not yet occurred in our industry	Similar event has occurred somewhere in our industry	Similar event has occurred somewhere within the BP Group	Similar event has occurred, or is likely to occur, within the lifetime of 10 similar facilities	Likely to occur once or twice in the facility lifetime	Event likely to occur several times in the facility lifetime	Common occurrence (at least annually) at the facility
A	8	9	10	11	12	13	14	15
B	7	8	9	10	11	12	13	14
C	6	7	8	9	10	11	12	13
D	5	6	7	8	9	10	11	12
E	4	5	6	7	8	9	10	11
F	3	4	5	6	7	8	9	10
G	2	3	4	5	6	7	8	9
H	1	2	3	4	5	6	7	8
Frequency	10^{-6} /yr or lower	$>10^{-6}$ to 10^{-5}/yr	$>10^{-5}$ to 10^{-4}/yr	$>10^{-4}$ to 10^{-3}/yr	$>10^{-3}$ to 10^{-2} /yr	$>10^{-2}$ to 10^{-1} /yr	$>10^{-1}$ to 1 /yr	>1 / yr
Probability	10^{-6} or lower	$>10^{-6}$ to 10^{-5}	$>10^{-5}$ to 10^{-4}	$>10^{-4}$ to 10^{-3}	$>10^{-3}$ to 10^{-2}	>.01 to 0.1	>.1 to 0.25	>.25

Table 5: Risk Tolerance Matrix [81]

For further information on how to apply the risk tolerance matrix, please refer to appendix C, where severity level definitions for impacts (consequences) are given as well.

The numbers (1-15) in the above matrix reflect the relative levels of risk (risk rating) with 1 being the lowest level of risk and 15 the highest. The colours in the table relate to the following reporting and endorsement levels for action plans:

Risk Category	Identified Leader for Notification and Endorsement
PURPLE	Segment chief executive or equivalent
BLUE	Entity leader
TURQUOISE	Facility leader
WHITE	This practice does not identify a leader for notification/endorsement for these risks.

Table 6: Notification Levels [81]

How a risk is considered, will depend on where the risk "lands" in the risk matrix. A higher authority has to accept increasing risk or order further research and risk mitigation efforts before approval. The concept of the risk tolerance matrix is important to grasp before stepping into the risk register.

Note that this risk matrix is focused towards the negative risks, and the mitigation and reduction of risk levels. This is most normally the base for final detailed planning. In the earlier stages of planning, positive risks (upsides) are more focused on as well, and these should be enhanced and supported for improvements. The risk matrix for upside risks could be a mirror picture of the above matrix, to reflect wanted and positive events.

5.3 Risk Register

The risk register is a risk assessment format that denotes and catches all risks and assesses them according to the risk tolerance criteria matrix. The risk register should be used proactively during operations by the operational engineer and Well Site Leader, to support the operation and contribute to increased operational safety with less unexpected downtime.

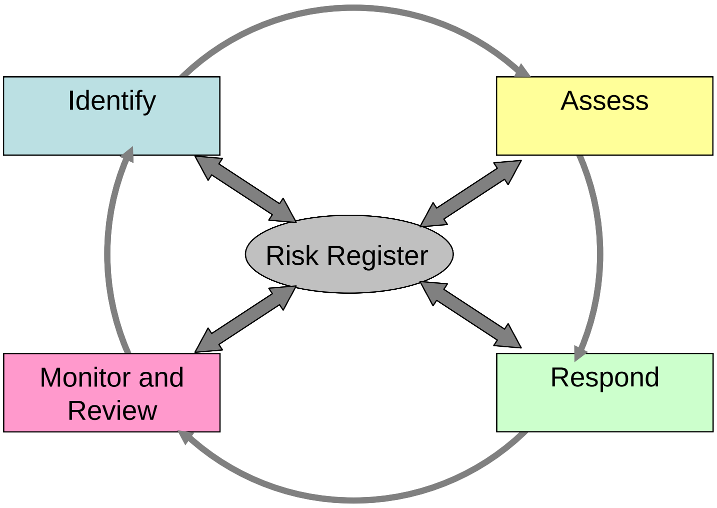


Figure 54: The Risk Management Process [81]

The group defined practice demands the following information to be part of a risk register:

- A risk title
- A description of the risk event
- The causes
- The potential HSE impacts (consequences)
- The potential financial and non-financial business impacts (delays to operation, damage to reputation, etc.)
- The estimated likelihood of occurrence (probability and frequency)
- The name of the person responsible for managing the risk (a risk owner is a person or entity with superior responsibility and authority to manage a risk)
- The additional actions or measures to further reduce the risk and the names of those responsible for the actions.

A recommended risk register approach for subsea well interventions has been established and can be found in appendix J. This risk assessment template will ensure that intervention engineers have to consider different risks in different contexts and be conscious of a broader risk awareness totality. BPs own risk assessment sheet has been used as a basis to improve the chance of implementation in the organisation. The original sheet has been modified, elaborated and different kick-off risks have been denoted as a starting point.

It is created as a template and must be tailored to each operation. Risks that are not relevant can be deleted, while other risks that have not been denoted for the specific well intervention at hand, needs to be included by the responsible engineer.

A risk register is commonly filled by use of:

- HAZID – HAZard IDentification (initial identification of potential hazards)
- HAZOP – HAZard and OPerability analysis (operational assessment of procedures and plans)
- FME(C)A – Failure Mode Effects (and Criticality) Analysis (perfectly suited for assessment of new and prototype equipment).
- "BORE" - BP Operation unit Risk Evaluation (a unit schedule risk assessment)
- Risk assessment made to support and obtain vessel acceptance by authorities (In Norway through the SUT (Samsvars UTtalelse) (performed according to the Maritime Directorate and PSA expectations
- Other (BP) risk assessment practices and methods.

A more complete list of risk assessment techniques can be found in appendix I.

5.3.1 Operational use

The dynamic and rapid nature of well intervention does not encourage risk assessments. Supervisors and engineers often have a hard time experiencing the gain of doing "too much" or unnecessary risk assessments, contributing to an already stretched workload. Therefore it is of the outmost importance to establish good systems and quality assurance loops to take care of proper risk management of all operations. This does not mean that a lot of work needs to be done for every single small well intervention job, but at least the existing risk analyses relevant for the operation are known to all involved parties, assessed for relevance and updated as needed. The risk register should be used in daily operational practice, in addition to other supporting "on site" risk mitigation tools such as such as Tool Box Talks and Safe Job Analysis. Risk assessments shall be performed by all participants and at all levels in a well intervention activity.

User value and relevance is key to ensure that the risk register is used during operation. Users are in this context defined as operation engineers, supervisors and their supporting crews.

Under any special circumstance, a risk assessment may be warranted. Is there new equipment in use? Is this a new campaign? Are there any special circumstances? Then a full risk assessment needs to be conducted.

5.3.2 Changes during operation

Changes during operation is a major accident potential driver, and one of the hard lessons learnt from the industry as a whole is that changes that are not properly managed can have unintended, and sometimes catastrophic consequences. Macondo, “the well from hell”, is a horrific example of what several last minute changes and delays can result in.

The Management of Change is one of BP’s eight Golden Rules and helps in assessing and manage changes to make sure there is no intolerable impact on safety of the business or the ability to reach objectives caused by the change.
The MoC process covers any change to plant, people or process that could introduce HSSE (Health, Safety, Security or Environment) risk or operational hazards that could have unforeseen consequences. The process applies to anyone directly involved in making a change. Even small changes can introduce significant hazards if not properly assessed or if used in the wrong context.

Changes create a need for an updated risk assessment. MoCs can also be a source from where to extract new lessons learnt. If what had to be changed this time is incorporated in the programme or procedure for the next similar job, than downtime or unplanned work may be avoided. The intention is to close the loop mentioned in section 5.3.1.

The BP Golden rule says [82]:

“ Work arising from temporary and permanent changes to organisation, personnel, systems, processes, procedures, equipment, products, materials or substances, and laws and regulations, cannot proceed unless a Management of Change process is completed, where applicable to include:

- A risk assessment conducted by all impacted by the change
- Development of a work plan that clearly specifies the timescale for the change and any control measures to be implemented regarding:
- Equipment, facilities and process
- Operations, maintenance, inspection procedures
- Training, personnel and communication
- Documentation

Authorisation of the work plan by the responsible person(s) through completion”

It is seen that the governing rule is specific and expectations to risk assessments for operational changes crystal clear. The only thing remaining is to actually do this in practice.

5.3.3 Subsea Well Intervention and Black Swans

It has been claimed [83] that we are focusing too much on the detailed operational and daily acknowledged risk picture when performing risk assessments. This may be and probably is true for subsea well interventions as well. It is therefore important to take a time-out from operational chores every now and then and give some focus to the negligible probability of "the perfect storm", or in other words - "The Black Swan", of subsea well interventions. The term “Black Swans” was introduced by the latin poet Juvenal and referred to something impossible, black swans did not exist. In 1697 a black swan was spotted on an expedition in Western-Australia and the term has since been used to describe something that is perceived as impossible but later proved to be true. Such events are often created by the coming together of more than one known phenomenon, but now arriving simultaneously in time, thereby aggravating the resulting impact on the operations. An example of a potential black swan incident has been included in the risk register of this thesis, more for illustration purposes than detailed analysis at this point in time. It is, however, recommended to gather the group every now and then to also assess potential extreme impact low probability accidental events.

Figure 55: Black Swan [91]

5.4 RLWI Risk management summary

Risk management refers to coordinated activities to guide and control how an organisation handles risk. There is a need for everyone involved in subsea operations to have a conscious and proactive relationship to risk. This can contribute to eliminate accidents that would otherwise have happened.

Risk focus has to be communicated clearly from the leadership team. The importance of this can be illustrated by an example:

If you see an unsafe activity offshore and your superior walks by without saying anything, would you still stop the work? Probably not, thinking if your superior thinks it is all right you should too. Everyone must know they have full company support in stopping work and taking time out for safety if something is perceived as unsafe.

If the recommended risk register approach for subsea well interventions (appendix J) is used proactively in the planning and during operations (when making changes) by the operational engineer and Well Site Leader, the operation will be prepared and run safer and with less unexpected downtime. Conditions that would otherwise go unnoticed (negative or positive risk) might be uncovered or by-passed. We cannot safeguard us against everything, so we need to focus on attitudes and culture that reduce unwanted risk and create an "automatic" risk awareness culture. Overall the risk register, matrix and risk framework impact levels imposed and required by BP group practices are adequate and satisfactory. The real challenge is making sure every department lives by the group practice. Local deviations have been exposed.

Recordable injury rate, and similar HSE related key performance indicators, should not alone be a focus in safety handling. Main focus has to be put on the well intervention work process safety and quality, which can be used in combating major accidents and reduce major accident potential for BP's subsea operations. Risk management activities should be traceable, creating an arena where continuous improvements can be picked up.

MoC follow up is a good source for new lessons learnt and should be incorporated extensively when reviewing lessons learnt from operations.

6.0 Discussion

The subject of this thesis demands for a very broad operational understanding and is very different from a thesis focusing on e.g. plugs. To be able to analyse lessons learnt and operational data, a basic and cohesive understanding for the entire offshore operation, procedures, equipment and offshore lingo is crucial. As the subject of subsea intervention is new to BP Norway, a broad definition of technology, equipment and operational procedures have been included.

Experience on a superior level has showed that light well intervention vessels are capable of performing sustainable well work on the NCS. There are several benefits to the CAT A vessels as they operate cheaper than rigs and represent a substantially more mobile and flexible alternative. The biggest drawbacks are operational capability (since the vessels currently perform pumping and wireline operations only) and weather limitations. One of the biggest cost drivers is time, and LWI vessels notoriously falls victim to waiting on weather. 6 m significant wave height will suspend operations, and future coiled tubing operations through rigid riser systems will have an even tighter operational window with a maximum heave compensation of 4 m. When it comes to contracting of these vessels, Statoil uses a contract which states that Statoil is only responsible for the well related activity in relation to well intervention operations. Everything that happens before and after is contractor responsibility under relevant maritime regulations. BP has not performed subsea interventions in Norway and should consider copying the Statoil approach. There is a lot of well work that needs to be done, and BP should seriously explore the opportunity of contracting one or two LWI vessels for year-round operations pending an economic value analysis.

Even though the LWI concept has proved its viability, there are still numerous improvement areas to make operations run more efficiently. The NPT fractions with a mean NPT of 17.3 % from the last three years confirm this. 81.2 % of the lessons learnt during subsea LWI operations stem from "Planning / Mobilisation", "Operations" and "Equipment". Analysing and cross-referencing these lessons has uncovered several repetitions of previously incurred unwanted incidents.

There is often confusion related to documentation and missing procedures. BP is giant company and it is close to impossible to know if all relevant data has been obtained. Storing systems are chaotic to say the least and it is not uncommon for individuals to have their own storing locations and preferences. Offshore this has been a recurring headache for WSLs as there can be several procedures (or none) for a specific operation and no clear instructions on which procedure to adhere to. It is common practice to refer to where the next procedure can be found in another document. This is too cumbersome and not satisfactory. One dedicated programme with all planned procedures included should be provided for each operation. Prior to mobilisation it should be decided which procedure to use or make up a combination of several procedures in one single document.

Where to find updated and relevant information in the huge and complex IT infrastructure seems to be a problem throughout the BP organisation, also for onshore engineers. How this challenge should be met throughout BP could be the basis for a new thesis subject.

For this thesis a recommendation for subsea light well intervention operations has been suggested: creating one specific folder for each operation would create a very simple “overall rule” on where to find relevant and up to date information for anyone involved in the offshore operation. A guideline as to what this folder should include could be made with the WIOG and WSL checklist (appendix G) as a basis and with other necessary documentation identified in pre-launch meetings with all contractors. This could alleviate the frustration experienced by contractors and 3rd parties and contribute to an overall increase in efficiency. This would also be helpful to any BP representatives on board, as all documentation needs have been clarified, included and ready for the offshore operation at hand. Having a requirement to go through all relevant documentation, could uncover i.e. lacking equipment testing and as such aid in preventing episodes such as the pulled weakpoint at Madoes.

Keeping documents up to date is another comprehensive challenge for the organisation. Well barrier schematics should always be up to date and even though it is not always practical to ensure that documents are consistently up to date, a minimum effort should at least include performing updates as often as practically possible. A dedicated person could be responsible for updating critical documents and hold meetings with involved parties to identify possible missing papers.

The operational reporting system “OpenWells” remain an irritation for intervention engineers. It is not practical to enter data into this drilling orientated system. It has been a desire for years to get a new separate reporting system customised for well intervention, and realisation of this desire is way overdue. As a compromise, “OpenWells” should at least be modified to include satisfactory reporting formats for intervention engineers. This would increase reliability and accuracy of BP operational reports, and this alone should be a good enough motivation to meet the intervention department request. The new Rushmore Reviews well intervention database will be a good source for further standardisation work of BP reports in the future.

The statistical analysis shows that equipment failures contribute significantly to NPT. Interface issues must take a large portion of the blame. Even small modifications offshore have led to downtime since the modified equipment was not verified for interface clashes. This phenomenon yields too much trouble time and needs to be addressed and acted upon as soon as possible to make sure any avoidable downtime related to this is eliminated. Clarifying contractors’ accountability would be a good starting point in combatting interface clashes.

Handling of equipment and lines through the moonpool has surfaced as a recurring problem, and should be facilitated by installing a camera in the moonpool area to pick up on any line entanglement or other issues that can create problems while performing the subsea well intervention.

New technology solutions (represented by Expro AX-S and Ziebel) should be followed closely. The technologies presented in this thesis have the potential to become a step change in intervention technology if successfully field tested. It is vital to pay close attention and support to new technology development to ensure BP do not miss out on any profitable opportunities.

It is important that the company process and export the recommendations from lessons learnt to future management systems, procedures, alert notices and “BP Well Intervention University” courses. Lessons learnt recording is an excellent platform for improving operational efficiency in the future and should as a minimum be maintained. The hectic nature of well interventions makes it hard to analyse and learn from the previous job before moving on to the next one.

To improve the learning loop a requirement to evaluate the job done prior to moving on to the next should be implemented as quality assurance measure. It should also be considered to establish a lesson learnt database and make it compulsory to check this database before and after conducting an operation. Improving the organisational learning platform in BP warrants a thesis on its own.

In order to combat unwanted downtime and unplanned surprises, a well intervention risk assessment template has been established. Implementation of the risk register template established in this thesis will help BP become best in class when it comes to risk management. Some of the idea is that the responsible engineer is forced to consider all risks denoted in the template and thereby get a broader risk consciousness. Causes for identified risks has been included to the original risk assessment form, as it is fundamental to evaluate the underlying reasons of a risk to be able to make mitigation recommendations. If the causes are not addressed, risk mitigation cannot be performed effectively.

It is often seen that pre-requisites for risk analyses (defining its validity) are unconsciously violated, with the potential of contributing to major accidents. Often the circumstances change, and some of the pre-requisites may change with them. This is seldom covered in risk assessments focusing on the new amendment or change in programme. This phenomenon has been incorporated in the risk template in this thesis by requiring the user to provide main and sub contexts. The most important contribution from the assessment template is to make engineers conscious of the different risks and the wider context and risk assessment validity in addition to just the limited job at hand.

A “copy-paste” approach will often be tempting for similar well interventions, i.e. for a drift run. It is important to be cautious since the context for the job may have changed, i.e. another LWI vessel is used or another well is entered. If the context is ensured and any potential changes to the work scope are identified, a copy-paste approach could be acceptable. There is no point in carrying out a risk assessment if it is not valid for its intended use. In fact, if such is done, it would become an added risk in itself by erroneously thinking a proper risk assessment has been completed.

Wrong focus and misunderstandings can cause serious accidents. The oil industry has to stop over-focusing on recordable injury rate as a sign of overall safety status for a facility. Main process safety and quality is the most important factor with regard to avoiding major accidents!

The risk assessment template and lessons learnt summaries will help transfer some of the subsea well intervention knowledge from BP UK to BP Norway. A lifetime of experience cannot be transferred in a few months however, and it is recommended to bring some of the subsea expertise over from Aberdeen to Norway to establish the subsea well intervention Norwegian chapter. Alternatively a challenge engineer could be sent to Aberdeen for an extended period of time and bring the knowledge obtained during this time back to Norway as part of a knowledge transfer project.

6.1 Sources of Error

In this thesis the lessons learnt and operational data material has been approached by focusing on NPT and operational efficiency on a level making the recommendations valid for any LWI vessel. There are several methods of approaching the subject and with alternative focus; i.e. only lessons from Seawell could have been studied to make specific recommendations for this vessel. An alternative approach could have made some results different from the ones presented in this thesis without making any of them right or wrong. There are several potential sources of error.

- Lessons learnt

Creators of lessons learnt have divided lessons learnt into broad categories, but it is often found that lessons do not fit the group they are assigned to, or have closer relation to other groups than the one it is located in. Some of the lessons learnt from success stories are very broadly painted in "management buzzword wording" and difficult to get anything concrete out of for an operationally oriented mind.

- BP reporting system "OpenWells"

It should be noted that the BP reporting system "OpenWells" (where the operational data is collected from) is configured for drilling purposes and not tailor-made for intervention use. Sometimes there are no appropriate choices for intervention reporting. OpenWells needs to be configured for intervention use, or a separate program should be developed to handle intervention operations. This would dramatically improve accuracy and ease for anyone involved in intervention operations. It is time consuming and limited in scope as to what can be practically entered by intervention engineers into the system as is today.

- Operational data

Sometimes operational data are incomplete, either caused by leaving a (NPT) field blank (i.e. no explanation as to the nature of the NPT) or by not providing a date for the occurrence. Data stored on different hard drives means there is no guarantee that all the relevant data has been found.

- Differing department culture

Each department operates fairly independent of one another. The governing documents such as group practices are supposed to make sure a minimum quality standard is met. These documents provide the frame for the enterprise, but sometimes the separate teams create their own culture, and their own way of performing work. This work is expected to comply with the governing documents but when compliance considerations are left up to an individual, deviations will occur. This can i.e. mean that some of the data used in this thesis may not be up to date if the department supplying this data has their own "system" by keeping up to date info on local hard drives.

- Inexperience

The author of this thesis has only been on one short visit offshore and lack offshore operational experience. Misinterpretation of the operational information could be a potential source of error

- Legislative differences

The lessons learnt sources stem from operations under the UKCS legislative regime, and not all elements are directly transferrable to the NCS regime.

6.2 Recommendations for Future Subsea Intervention Operations on Skarv

LWI vessels are capable of performing mainly wireline and pumping services (still not household coiled tubing through tensioned riser systems) for the Skarv field. As this thesis has shown, BP has extensive experience in subsea LWI – the depths and experience from the fields West of Shetland are very relevant for the Skarv field.

Due to a production start delay, several of the pre-drilled production wells have been shut-in much longer than anticipated. This may cause a need for clean-out well intervention operations. These interventions will most probably be performed by the contracted drilling unit already on location.

A selection of mechanical failures, flow assurance and reservoir management related intervention frequencies are based on an evaluation made by the Wells and subsurface teams. This evaluation has concluded with an assumed intervention need of the following:

Intervention Category	Intervention Type	Number of Interventions (Life-of Field)
Mechanical interventions	Production packer or tubing leak	1
	Down Hole Safety Valve (DHSV) repair	3
	Sand Control Interventions	1
	Tubing hanger repair	1
Flow assurance	Pumping scale chemicals	5
	Hydrate incidents	4
Reservoir management	Unplanned sidetracks	4
	Zonal isolation	1
	Production logging campaign	2

Table 7: Preliminary Skarv Well Intervention Plan [84]

For the two production logging campaigns, there are 5 planned production logging operations with a LWI vessel and 4 in conjunction with unplanned sidetracks from the drilling unit. The vessel PLTs have been planned to better understand individual zone contributions from the wells. The duration of a PLT campaign has been estimated to 34 days.

The numbers from the UKCS and West of Shetland shows that an average duration of a PLT operation is 14 days, so the total number has been set to 5 although this exceeds the 68 available days with two days (70 days in total). These numbers are still preliminary as production has still not started.

BP has estimated that there is a low to moderate risk of calcium carbonate precipitation. Because of this, calcium carbonate scale prevention is assumed and 5 chemical treatments of the oil producers by pumping from a vessel hooked up on the template manifold is included in the intervention plan. The wells with a deviation higher than 30 degrees will be completed with sand screens to account for future pressure depletion, drawdown conditions and water breakthrough. Based on this, one sand control repair intervention has been included in the estimate. In addition, 4 hydrate incidents are included for the gas producers in the Garn and Idun reservoirs. Inhibition lines are included in the subsea architecture but based on experience, some hydrate problems are expected.

Recommendations for future subsea intervention operations on Skarv:

- Of the three vessels presented in this thesis, the Island Constructor would be the better choice for subsea well intervention operations. Diver redundancy is not desirable on the NCS as companies strive to eliminate use of divers in Norwegian waters, and diver facilities would tie up space unnecessarily. The Island constructor is capable of handling all of the presumed intervention needs except from sidetracking. A full market analysis should be made when deciding which vessel to use, to identify other potential vessel candidates.

- Make use of the subsea intervention lubricator system, and thereby take advantage of previous and proven BP experience.

- All information and documentation needed for the subsea well intervention operation at hand should be gathered in a single operation or well specific folder.

- Verify equipment interface compatibility prior to mobilisation and after modifications during operations to avoid interface clashes.

- Implement and proactively make use of the recommended lessons learnt and risk register approach for subsea well interventions (appendix J).

7.0 Conclusion

Cross-referencing the lessons learnt, in combination with studying operational data and risk management have uncovered several key points that can help improve operational efficiency and ultimately increased oil recovery from the NCS:

- 81.2 % of the lessons learnt stems from “Planning / Mobilisation”, “Operations” and “Equipment”. These strategic components should be a focus area when planning subsea well intervention operations for BP going forward. Lessons learnt and operational data analysis is effective in gaining an overview of what the organisation should focus on to improve operational efficiency.

- Equipment failure is the main NPT contributor, and interface clashes (both prior to mobilisation and after being modified during operations) are the main equipment and operations failure mode. It is crucial to evaluate interface compatibility prior to mobilisation but also after any modification (even minor) is made during operations.

- The second biggest NPT contributor is “waiting on weather”. Wind, current, waves, rain, snow and ice of course vary from day to day, month to month, but over several years the totality is a stable risk factor with a known expectancy.

- Implementing requirements to go through all relevant documentation prior to mobilisation, could uncover i.e. lacking equipment testing and aid in preventing episodes such as the pulled weakpoint at Madoes. It is recommended to create one distinct folder for each well or operation and give all participants full access to this specific folder. Require every subsea well intervention participant to include any needed documentation in this specific folder.

- The practice of indicating where to find the next operational step and in which procedure is too cumbersome. Send only one dedicated programme procedure out with the vessel. Decide which procedure to use or make up a combination in one document.

- The BP reporting system should be customised for intervention purposes or a separate program should be ordered. This will improve future report quality and especially the accuracy and reliability.

- Risk management should be strengthened by including causes and context in the risk register. A risk assessment can be useless if the correct context is not established.

Nomenclature

A
AGA = American Gas Association
AHC = Active Heave Compensated
AoC = Acknowledgement of Compliance
API = American Petroleum Institute
ASTM = American Society for Testing and Materials

B
BHA = Bottom Hole Assembly
BOEPD = Barrels of Oil Equivalents Per Day
BOPD = Barrels of Oil Per Day
BORE = BP Operation unit Risk Evaluation
BOP = Blow Out Preventer
BRT = Below Rotary Table

C
CAT = Category
CBV = Cutting Ball Valve
CCR = Central Control Room
CIU = Chemical Injection Unit
CMC = Crown Mounted Compensator
CT = Coiled tubing

D
DAS = Distributed Acoustic System
DnV = Det norske Veritas
DP = Dynamic Positioning
DTS = Distributed Temperature System
DWOP = Drilling and Well Operations Practices

E
ECA = Easington Catchment Area
EMAS = Eco-Management and Audit Scheme
EN = European Standard
EOR = Enhanced Oil Recovery
EQD = Emergency Quick Disconnect
ESD = Emergency Shutdown
ETAP = Eastern Through
EU = European Union

F
FME(C)A = Failure Mode Effect (and Criticality) Analysis
FOC = Fibre Optic Cable
FPSO = Floating Production Storage and Offloading

G
GDP = Group Defined Practice
GI = Gas Injector
GoM = Gulf of Mexico
GOR = Gas Oil Ratio
GP = Group Practice
GP = Gas Producer

H
HAT = Highest Astronomical Tide
HAZID = Hazard Identification
HAZOP = Hazard and Operability Analysis
HC(s) = Hydrocarbon(s)
HHP = Hydraulic Horsepower
HPHT = High Pressure High Temperature
HPU = Hydraulic Power Unit
Hs = Significant Wave Height
HSE = Health, Safety and Environment
HSSE = Health, Safety, Security and Environment

I
IEC = International Electrotechnical Commission
IMO = International Maritime Organization
IOR = Increased Oil Recovery
ISO = International Organization for Standardization
ISPS = International Ship and Port facility Security

L
LARS = Launch and Recover System
LAT = Lowest Astronomical Tide
LIB = Lead Impression Block
LLP = Lower Lubricator Package
LOT = Leak Off Test
LSA = Low Specific Activity
LTV = Lower Test Valve
LT = Lubricator Tubular
LWI = Light Well Intervention

M
MAASP = Maximum Allowable Annular Surface Pressure
M&G = Meet and Greet
MEG = Mono-Ethylene Glycol
MHT = Module Handling Tower
MoC = Management of Change
MODU = Mobile Offshore Drilling Unit
MOP = Maximum Operating Pressure

N
NORM = Naturally Occurring Radioactive Material
NORSOK = NORsk SOkkels Konkurranseposisjon
NPD = Norwegian Petroleum Directorate
NPT = Non-Productive Time
NS = Norwegian Standard

O
OLF = Norwegian Oil Industry Association
OP = Oil Producer
OREDA = Offshore Reliability Data

P
PA = Public Address
PCH = Pressure Control Head
PLT = Production Logging Tool
PoB = Personnel on Board
POOH = Pull Out Of Hole
PSA = Petroleum Safety Authority

Q
Q = Quarter (i.e. Q4 = Quarter 4)

R
RF = Recovery Factor
RIH = Run In Hole
RLWI = Riserless Light Well Intervention
ROV = Remotely Operated Vehicle
RP = Recommended Practice

S
SCM = Subsea Control Module
SCP = Sustained Casing Pressure
SIL = Subsea Intervention Lubricator
SJA = Safe Job Analysis
SLB = Schlumberger
SP = Spontaneous Potential
SSR = Shear-Seal Ram
SSTV = Slow Scan Television
SUT = Samsvarsuttalelse
SWL = Safe Working Load

T
TBT = Tool Box Talk
TOFS = Time Out For Safety
TRT = Tree Running Tool
TTRD = Through Tubing Rotary Drilling

U
U = Umbilical
UHF = Ultra High Frequency
UK = United Kingdom
UKCS = United Kingdom Continental Shelf
ULP = Upper Lubricator Package
UTH = Umbilical Termination Head

V
VHF = Very High Frequency

W
WCP = Well Control Package
WH = Wellhead
WIOG = Well Intervention Operation Guidelines
WL = WIreline
WOCS = Work Over Control System
WSL = Well Site Leader
WTW = Wire Trough Water
WUOK = Well Ops UK (company)

X
XLOT = Extended Leak Off Test
XMT = Christmas tree

Bibliography

[1] Botros, F., et. al. *BP's Subsea Developments: Past Successes and Future Challenges*, SPE 113652, Indian Oil and Gas Technical Conference and Exhibition, Mumbai, India, 4-6 March, 2008.

[2] http://www.slb.com/~/media/Files/resources/oilfield_review/ors99/win99/pages2_19.ashx

[3] "Skarv Development, Reservoirs Surveillance Plan", BP Document, October 2008.

[4] "Skarv Idun, Plan for Development and Operation (PDO) and Plan for Installation and Operation (PIO)", BP Document, June 2007.

[5] "Intervention in subsea wells", University in Stavanger(UiS) Lecture Presentation.

[6] http://www.sut.org.au/perth/perth_events/presentations/120222_subsea_australasia_conference/120222_Morten%20Iversen_PUSHING%20THE%20SUBSEA%20WELLS%20OIL%20RECOVERY%20FACTOR.pdf

[7] http://www.standard.no/PageFiles/1315/D-010r3.pdf

[8] http://www.ptil.no/role-and-area-of-responsibility/category165.html?lang=en_US

[9] http://www.ptil.no/acknowledgement-of-compliance-aoc/category159.html?lang=en_US

[10] http://www.regjeringen.no/nb/dep/oed/dok/NOU-er/1999/NOU-1999-11/6/1.html?id=352695

[11] OLF Plug & Abandonment Workshop, Thursday 14th June 2012, Sola Quality Airport Hotel.

[12] Howard, R., "BP Rep End of trip Report", Seawell, Don Field, June 2010.

[13] Finlay, Fraser, "Light Well Intervention", BP internal powerpoint presentation, November 2009.

[14] "DP positioned well intervention", UKCS-MAL-010, BP minimum requirements for vessel and unit contracting. Revision date: January 2011.

[15] http://www.statoil.com/en/NewsAndMedia/PressRoom/Downloads/CatB%20rig%20-%20illustration%202.jpg

[16] http://www.ptil.no/nyheter/samtykke-til-bruk-av-island-constructor-article8106-24.html

[17] http://fishsafe.eu/no/offshorestrukturer/fotogalleri.aspx

[18] http://www.statoil.com/en/NewsAndMedia/PressRoom/Downloads/Fact%20sheet.pdf

[19] Eikill, Geir Ove, *"Workhorse Rigs", Tailor-made for Production Drilling at Existing Mature Fields on the Norwegian Continental Shelf*, OTC 21092, Offshore Technology Conference, Houston, Texas, USA, 2-5 May, 2011.

[20] Headworth, C., et. al., *New Well Intervention Technology That Will Enable Increase In Recovery Rate*, OTC 15182, Offshore Technology Conference, Houston, Texas, USA, 5-8 May, 2003.

[21] Skeie, T., et. al., *Riser Less Well Intervention for Subsea Work Over*, SPE 143226, Offshore Conference and Exhibition, Macaé, Brazil, 14-17 June, 2011.

[22] http://www.statoil.com/en/NewsAndMedia/PressRoom/Downloads/Fact_sheet_Cat_B.pdf

[23] Lundie, Jaime, "Well Site Leader's Guide to the Island Constructor", BP document, September, 2009.

[24] http://www.ulstein.com/Kunder/ulstein/mm.nsf/inpdocuments/D73AD6B527F49734C12574520033C10F/$file/Bygg%20279%20Island%20Constructor_Produktark.pdf

[25] http://www.satmagazine.com/cgi-bin/display_article.cgi?number=1497139859]

[26] http://www.helixesg.com/newsflash/newsflash.asp?Mode=View&articleid=37&Category=All

[27] http://www.helixesg.com/default/EnergyServices-WellOPS/Downloads/Well%20Enhancer.pdf

[28] Silva, Antonio, "Well Site Leader's Guide to the Well Enhancer", BP document, June, 2011.

[29] http://www.johnbage.pwp.blueyonder.co.uk/The%20Ships.htm, 10:52, 21.03.12

[30] http://contentmobi.com/mobsitestore/1318/images/file/Seawell.pdf

[31] Zwaag, Claas can der, "Well Completions 08, Planning – Technology – Regulations", University in Stavanger (UiS) Lecture Presentation, fall 2011.

[32] Machar Light Well Intervention Performed From "Island Constructor", Procedure, Document no. 06-1981-1027-PRO-U-002.

[33] http://www.nsfs.org/filer/LSA_Scale_Christensen.pdf

[34] http://www.norse-decom.no/en/lra.htm

[35] BP UK, "Machar W127 Sub Sea Light Intervention", Project Manual, July, 2010.

[36] http://www.saqrport.ae/Community/TidesWeather.aspx

[37] Shell Exploration and Production, "Seawell For Dummies", Pdf document, November, 2007.

[38] Stald, T.,C., *Assessment of critical factors when running and retrieving Framo pump modules through moonpool,* Master thesis, University in Stavanger (UiS), June, 2011.

[39] http://www.rolls-royce.com/Images/RR_B_4s_FactSheet_OdimWellInt_0810_8_tcm92-26108.pdf

[40] http://www.akersolutions.com/en/Global-menu/Products-and-Services/technology-segment/Subsea-technologies-and-services/Subsea-production-systems-and-technologies/Umbilicals-and-power-cables/Composite-Technology-/]

[41] http://large.stanford.edu/publications/coal/references/ocean/rovs/tools/docs/h1.pdf

[42] http://www.interventiontechnology.com/pt/cms/user_files/File/PDFs/ROV_Intervention_Catalogue.pdf

[43] http://www.fesinternational.com/pdf/HotStabSpec.pdf

[44] http://www.asiaoec.com/content/John_Reid_CHARLES_TAYLOR_ENERGY.pdf

[45] Skeels, H., B., et. al., *The Horizontal Subsea Tree: A Unique Configuration Evolution*, OTC 7244, 25th Annual OTC, Houston, Texas, USA, 3-6 May, 1993.

[46] http://www.subnetservices.com/blog/2010/04/09/subsea-simulated-wellhead-xmas-tree-improvements-rov-training-area

[47] Modified from: http://www.sut.org.au/perth/perth_events/presentations/120222_subsea_australasia_conference/120222_Morten%20Iversen_PUSHING%20THE%20SUBSEA%20WELLS%20OIL%20RECOVERY%20FACTOR.pdf

[48] Sangesland, Sigbjørn, "Drilling and Completion of subsea wells – An Overview", Lecture Presentation in subject TPG4200 – Subsea Production Systems, rev. 1,NTNU, January, 2011.

[49] http://www.pennenergy.com/index/petroleum/display/126098/articles/offshore/volume-61/issue-10/news/active-heave-compensation-winches-offer-low-weight-power-consumption.html

[50] Hughes, E., W., et. al., *Development and Testing of an Active Motion Compensation System for Production System Support*, OTC 6258, 22nd Annual OTC in Houston, Texas, 7-10 May, 1990.

[51] Jøssang, S., N., et. al. *Present and Future Well Intervention on Subsea Wells,* IADC/SPE 112661, IADC/SPE Drilling Conference, Orlando, Florida, USA, 4-6 March 2008.

[52] http://exprogroup.com/wp-content/uploads/AX-S-Corp-Brochure-.pdf

[53] Solheim, A., et. al., *The Tommeliten Subsea Project,* SPE 19264, Offshore Europe 89, Aberdeen, UK, 5-8 September, 1989.

[54] "Wireline", University in Stavanger (UiS) Lecture Presentation, 2010.

[55] "Introduction to Coiled Tubing Services", Schlumberger presentation for University in Stavanger (UiS) visit, October, 2011.

[56] Coiled Tubing A + B, University in Stavanger (UiS) Lecture Presentation, 2011.

[57] http://www.accessmylibrary.com/coms2/summary_0286-9315270_ITM

[58] http://www.rpsea.org/forums/auto_scranton.pdf

[59] http://www.akerdrill.com/section.cfm?path=20-22

[60] http://careers.exprogroup.com/EXPRO_AX-S.pdf

[61] http://exprogroup.com/wp-content/uploads/AX-s-Newsletter_Issue-16_aw.pdf

[62] "Ziebel Company Introduction", Zielbel Presentation, September, 2011.

[63] "Z-system Applications", Ziebel Presentation, September, 2011.

[64] "Where We Operate", Discover BP Presentation, BP Intranet.

[65] http://www.oreda.com/

[66] Moulds, T., P., et. al., *Magnus Field: Reservoir Management in a Mature Field Combining Waterflood, EOR, and New Area Developments,* SPE 96292, Offshore Europe, Aberdeen, UK, 6-9 September, 2005.

[67] http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_magnus.pdf

[68] http://www.bg-group.com/ukinfrastructure/SouthernNorthSea/Pages/EasingtonCatchementArea.aspx

[69] http://www.bp.com/genericarticle.do?categoryId=2012968&contentId=7074070

[70] http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_schiehallion.pdf]

[71] http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/U/uk_asset_bruce.pdf]

[72] http://www.subseaiq.com/data/Project.aspx?project_id=777&AspxAutoDetectCookieSupport=1

[73] "Unplanned Breaking of Weak Point", Incident Investigation Report, North SeaWell Interventions Team – Subsea. BP Report.

[74] P211 Success Story, BP PowerPoint Presentation, May, 2009.

[75] Ninian Success Story, BP PowerPoint Presentation, October, 2009.

[76] BP Internal Newsletter, 1st edition. 2012

[77] http://www.offshore.no/jobbsak/34634_norges_yngste_risk_manager

[78] ISO 31000:2009 “Risk Management – Principles and guidelines”, ISO Standard

[79] Handout, Risk Manager Course for Accredited Certification as Risk Mananager, January 2012.

[80] Bergin, Tom, – “Spills and Spin: The Inside Story of BP”, Published by Random House Business Books, ISBN 9781847940827, 2011.

[81] *Assessment, prioritization and management of risk,* BP Group Defined Practice *GDP 3.1-0001*

[82] HSE Handbook, BP, 2012 edition.

[83] Aven, T., - “Om perfekte stormer og sorte svaner”, Article in Stavanger Aftenblad, 14th of May 2012.

[84] Skarv Idun Plan for Development and Operation (PDO) and Plan for Installation and Operation (PIO), BP Document, June, 2007.

[85] G-21 Wireline Perforation, BP Well Intervention Program, Document Number: NS-I-NO-WM-38.

[86] Sutherland, M., “NPT-Event – HC Vent Hose Damage”, BP PowerPoint Presentation, Devenick S1, Island Constructor, April, 2011.

[87] Lundie, J., “Coupler Shrouds Removed From EWT Tree”, BP PowerPoint Presentation, Devenick S1, Island Constructor, May, 2011.

[88] Lundie, J., “Torque Bucket Damage During Tree Retrieval”, BP PowerPoint Presentation, Devenick S1, Island Constructor, May, 2011.

[89] Subsea Tree Population Poster, BP Internal.

[90] ISO 31010:2009 “Risk Management – Risk Assessment Techniques”, ISO Standard

[91] http://029d6c2.netsolhost.com/tours2007/yorkshire.html

[92] Lundie, J., Well Site Leaders LWI Checklist, BP Excel sheet, November, 2010.

Appendices

Appendix A – Detailed plan for workflow

Tentative execution schedule, to be adjusted underway, and on University recommendation:

Timeline	Task progress
December 2011	• Thesis kick-off • Start-up discussion meeting in Stavanger, with BP well intervention team (28-30 December) • Approval of thesis plan by University
January 2012	• ISO Risk Manager Certification Course • Establish main hypotheses and main work flow for thesis • Candidate to acquire and acquaint himself with relevant technical background knowledge. • Final thesis focus selection: Select hypotheses to continue working towards in the bulk of the thesis; methodology and vessels' capabilities to be part of selected work scope.
February – March 2012	• Candidate to dig into the national and international status and capabilities for subsea well intervention, particularly Norwegian and UK waters. Identify differences, existing methods, capabilities, requirements and indications of future changes. • Candidate to dig into the national and international standards and internal company requirements to well interventions, particularly ISO, NORSOK and BP practices. • Candidate to get fully versed in relevant definitions and issues. • Establish detailed summaries and illustrative reporting formats of thesis subject • Candidate to get fully up to speed with the relevant BP tools, and prepare recommendations for improvements. • Establish field well intervention experience and development, classified by main types, duration, cost and quality – are we getting better, worse, why? Documentation by using available field data. • Well intervention complexity drivers identified such as age of wells, type of wells, mechanical plugs, well clean-ups, wire line, coiled tubing, etc. • Summary of rules and regulations and literature search and BP experience in general and in relation to subsea well intervention. • Regular presentations to BP and University for correction of thesis focus.

Timeline	Task progress
April – May 2012	• Field Trip to Brazil over Easter 2012 • Assessment of existing methods. Assessment of experience in industry to the degree available. • Elaboration of BP specific requirements and needs. • Deeper assessment of industry practice for selected focus area. • Analysis of the optimal split between well intervention vessel types, rigs and other vessels / methods for minimum cost. • Assessment of important KPI to use (Key Performance Indicator) • Assessment of Rushmore Reviews Intervention Performance Review database for well interventions. What to get out, and how. • Prepare for benchmarking towards other operators, if enough data is available) via Rushmore or other sources.
June 2012	• Polishing of Master Thesis report. • Recommendations to upgrade BP processes • Make recommendations on how efficiency/productivity improvements and cost reductions are realistically obtainable and in line with the company objectives and observing HSE requirements. • Make recommendations to improve efficiency and productivity measurements in relation to present status (KPI, management system, etc.) • Analyses, conclusions and recommendations based on all the above work done. • Deliver thesis for approval by University. • Presentation to advisory team in BP.

Table 8: Detailed Plan for Workflow

Appendix B – BP Risk Consideration Matrix for dry tree interventions

	Risk Consideration	Rating	Score	Comments
1	Operation Non-Routine (< 6 per year), or Non-standard (not a repeat of previous operation, unusual circumstances).	1	0	
2	First use of new tool/technique on this Field or operation may have adverse effect on production facilities. (May have been used on other fields.)	1	0	
3	Originator not familiar with platform/Field (<25% of programmes in last 6 months).	2	0	
4	Operation renders DHSV temporarily inoperable (pull DSHV, sleeve installed or temporarily locked open, or pull GLV)	1	0	
5	Operation involves continuous operations with toolstrings and/or BHAs across Xmas trees valves (e.g. Set Tubing Hanger plugs)	1	0	
6	Involves coiled tubing operations with BHA at HUD.	1	0	
7	Operation involves use of Hazardous Materials (e.g. acid, chemical cutter)	1	0	
8	Involves coiled tubing operations in a well having a CIWHP > 3,000 psi.	1	0	
9	Unknown well conditions (>2 years from last well entry, or well has scale/asphalting problems or hydrate formation potential exists).	1	0	
10	Poor mechanical condition of well e.g. leaking Xmas tree valve, corroded or leaking tubing, leaking GLV	1	0	
11	Fishing operation	2	0	
12	Is dispensation from BP or Contractors' Policy, or a Safety Case modification required?	3	0	
13	Involves utilizing the DHSV as a barrier	3	0	
14	DTI Licence consent, HSE notification, or job specific examination (under DCR Legislation) required?	3	0	
	Total Criticality Score			

Programme Approval

Total Criticality Score	Required Approvals/Actions
0 – 6	Programs to be reviewed by senior engineer and approved by TL (or delegate)
6 or more	Separate approver and independent endorser required (Norway TA) in addition to above

Table 9: Risk Consideration Matrix for Dry Tree Interventions [85]

Appendix C – BP Risk Register supportive material

SEVERITY	HEALTH AND SAFETY	ENVIRONMENTAL
A Levels A-C maintain the visibility of risks with the potential for catastrophic impact even if their probability of occurrence is extremely low. The upper level of this framework is defined by the most severe level of impact ever seen in industry.	Comparable to the most catastrophic health/ safety incidents ever seen in industry. The potential for 100 or more fatalities (or onset of life threatening health effects) shall always be classified at this level.	• Future impact, e.g., unintended release, with widespread damage to any environment and which remains in an "unsatisfactory" state for a period > 5 years. • Future impact with extensive damage to a sensitive environment and which remains in an "unsatisfactory" state for a period > 5 years. • Future impact with widespread damage to a sensitive environment and which can only be restored to a "satisfactory"/agreed state in a period of more than 1 and up to 5 years.
B	Catastrophic health/ safety incident causing very widespread fatalities within or outside a facility. The potential for 50 or more fatalities (or onset of life threatening health effects) shall always be classified at this level.	• Future impact with extensive damage to a non-sensitive environment and which remains in an "unsatisfactory" state for a period > 5 years. • Future impact with extensive damage to a sensitive environment and which can only be restored to a "satisfactory"/agreed state in a period of more than 1 and up to 5 years. • Future impact with widespread damage to a non-sensitive environment and which can only be restored to a "satisfactory"/agreed state in a period of more than 1 and up to 5 years. • Future impact with widespread damage to a sensitive environment and which can be restored to an equivalent capability in a period of around 1 year.
C	Catastrophic health/ safety incident causing widespread fatalities within or outside a facility. The potential for 10 or more fatalities (or onset of life threatening health effects) shall always be classified at this level.	• Future impact with extensive damage to a non-sensitive environment and which can only be restored to a "satisfactory"/agreed state in a period of more than 1 and up to 5 years. • Future impact with widespread damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of around 1 year. • Future impact with extensive damage to a sensitive environment and which can be restored to an equivalent capability in a period of around 1 year. • Future impact with widespread damage to a sensitive environment and which can be restored to an equivalent capability in a period of months.

SEVERITY	HEALTH AND SAFETY	ENVIRONMENTAL
D	Very major health/ safety incident The potential for 3 or more fatalities (or onset of life threatening health effects) shall always be classified at this level. 30 or more injuries or health effects, either permanent or requiring hospital treatment for more than 24 hours.	• Future impact with extensive damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of around 1 year. • Future impact with localized damage to a sensitive environment and which can be restored to an equivalent capability in a period of around 1 year. • Future impact with widespread damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with extensive damage to a sensitive environment and which can be restored to an equivalent capability in a period of months.
E	Major health/ safety incident 1 or 2 fatalities, acute or chronic, actual or alleged. 10 or more injuries or health effects, either permanent or requiring hospital treatment for more than 24 hours.	• Future impact with localized damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of around 1 year. • Future impact with extensive damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with localized damage to a sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with extensive damage to a sensitive environment and which can be restored to an equivalent capability in a period of days or weeks.
F	High impact health/ safety incident Permanent partial disability(ies) Several non-permanent injuries or health impacts. Days Away From Work Case (DAFWC)	• Future impact with localized damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with immediate area damage to a sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with extensive damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of days or weeks. • Future impact with localized damage to a sensitive environment and which can be restored to an equivalent capability in a period of days or weeks.

G	Medium impact health/ safety incident Single or multiple recordable injury or health effects from common source/event.	• Future impact with immediate area damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of months. • Future impact with localized damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of days or weeks. • Future impact with immediate area damage to a sensitive environment and which can be restored to an equivalent capability in a period of days or weeks.
H	Low impact health/ safety incident First aid Single or multiple over-exposures causing noticeable irritation but no actual health effects	• Future impact with immediate area damage to a non-sensitive environment and which can be restored to an equivalent capability in a period of days or weeks.

Table 10: Risk Framework – HSE Impact Levels [81]

SEVERITY*	Non-Financial Impact	Financial Impact (EQUIPMENT DAMAGE, BUSINESS VALUE LOST)
A	Public or investor outrage on a global scale. Threat of global loss of license to operate.	>$20 billion
B	Loss of license to operate a major asset in a major market – US, EU, Russia. Intervention from major Government – US, UK, EU, Russia. Public or investor outrage in major western markets – US, EU. Damage to relationships with key stakeholders of benefit to the Group.	$5 billion - $20 billion
C	Loss of license to operate other material asset, or severe enforcement action against a major asset in a major market. Intervention from other major Government. Public or investor outrage in other material market where we have presence or aspiration.	$1 billion - $5 billion

D	Severe enforcement action against a material asset in a non-major market, or against other assets in a major market. Interventions from non-major Governments. Public or investor outrage in a non-major market, or localised or limited "interest-group" outrage in a major market. Prolonged adverse national or international media attention. Widespread adverse social impact. Damage to relationships with key stakeholders of benefit to the Segment.	\$100 m to \$1 billion
E	Other adverse enforcement action by regulators. Limited "interest-group" outrage in non major market. Short term adverse national or international media coverage. Damage to relationships with key stakeholders of benefit to the SPU.	\$5m -\$100 m
F	Regulatory compliance issue which does not lead to regulatory or other higher severity level consequence Prolonged local media coverage. Local adverse social impact. Damage to relationships with key stakeholders of benefit to the Performance Unit (PU).	\$500k-\$5m
G	Short term local media coverage. Some disruption to local operations (e.g., loss of single road access less than 24 hours).	\$50k -\$500k
H	Isolated and short term complaints from neighbours (e.g., complaints about specific noise episode).	<\$50k

Table 11: Risk Framework – Business Impact Levels [81]

Appendix D - Selected examples, NPT lessons learnt format

Summary of lessons learnt from NPT incidents in 2011 includes:

- **Hydrocarbon (HC) vent hose damage**

INCIDENT SUMMARY

The HC vent hose is part of the nitrogen and hydrocarbon vent system and was made up to the ROV stab, which consists of a crossover fitting and a hub. On reaching 3 bar a small leak was detected between the hub and the crossover. The hose was disconnected, and the crossover fitting and hub unmade. The hose was suspended from a sheave approximately 8m above the deck during this operation, making it difficult to prevent weight acting on the fittings. No damage was visible on the sealing surfaces, so the crossover and hub connection was remade, slightly tighter than before to try and prevent a further leak. The hose was then reconnected to the crossover fitting, but the weight and angle of the hose lead to difficulties in tightening the connection. Therefore the decision was made to undo the hose again. Upon undoing the hose damage to the thread profile was visible on both the hose and the crossover fitting. Both threads are made of stainless steel 316 and no lubrication was used whilst making up the connection.

IMPACT

Island NPT:
32.75 hours ~
£270K

BP NPT:
0 hours

Change in fitting and hot stab used

ACTION TAKEN

- Supplier of the hose was contacted to check the correct fittings had been supplied. Comparison with the drawings confirmed it was the correct fittings.

- Spare parts were flown to the vessel with a technician for changing and retesting the new fittings to 15000psi.

- The crossover was changed to a 2"Weco connection and made up to the Well Kill Stab instead of the ROV stab as previously.

IMMEDIATE / ROOT CAUSES

- The task was not sufficiently assessed and planned causing unnecessary difficulty when connecting the hose to the crossover fitting.
- Stainless steel 316 is a material prone to galling. Pitting present on the crossover also suggests poor quality material, which further increases the chances of galling.
- There was a lack of familiarity among the crew for making up this fitting as the HC vent system is a newly installed system.
- The fitting was specially made and no spares were available on board, leading to an increase in NPT whilst waiting for parts to be flown out.

RECOMMENDATIONS / ACTIONS

- Continue to use the Well Kill stab for the remainder of this project.

- Island to highlight to the crew the difficulties in making up this fitting.

- Spare parts to be carried onboard to prevent an increase in downtime if the problem were to occur again.

PICTURES

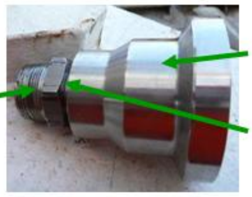
Thread on hose

Thread on crossover fitting

Galling of thread profile

Crossover fitting

Note: there are no markings or identification of any kind on this fitting, including no pressure rating marking



Hub for ROV stab

Location of leak

Figure 56: Hydrocarbon Vent Hose Damage, Lesson Learnt [86]

- **Loose coupler shrouds**

INCIDENT SUMMARY

The Tree Running Tool (TRT) was failing to fully land on the XMT and the hydraulic couplers were not fully making up. A gap of approximately 1”, as shown in pictures 2 and 3 was visible. Pulling up on the TRT showed that some of the shrouds protecting the male couplers on the tree were loose. Removal of 5 loose shrouds then allowed the TRT to fully land out and lock.
After the shrouds were recovered to the surface they were test fitted with a spare coupler set. The coupler did fit inside the shroud, though the tolerance was tight. One of the couplers had a thin layer of a black coloured deposit on the inside, though this did not prevent the coupler from fitting inside. From the appearance of the couplers there is no visible reason for them to have prevented the TRT locking to the tree.

IMPACT

Additional time required for fitting the TRT resulting in an overall schedule impact

ACTION TAKEN

- Removed loose shrouds and re-ran the couplers successfully.

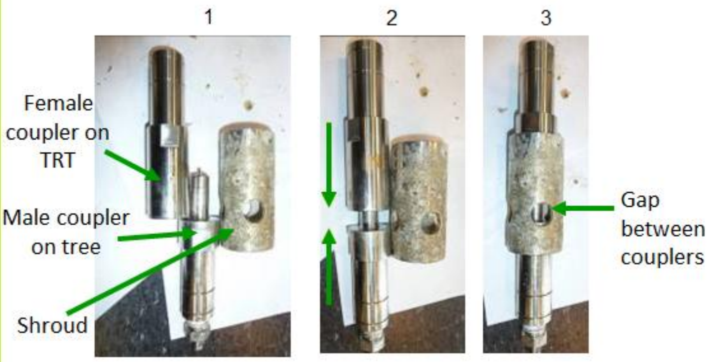
IMMEDIATE / ROOT CAUSES

- The extra marine growth on the inside of the couplers created enough friction to prevent the couplers being able to fully make up.
- The couplers on the tree/TRT were slightly misaligned, causing them to bind up when pushed together.

RECOMMENDATIONS / ACTIONS

- Double check that shrouds are tight.
- Be aware of possible recurrences.

PICTURES



1. The female and male parts of the couplers should meet up fully so that the male stab is completely covered.

2. From this point onwards a large force is required to push the two couplers together fully.

3. View of the couplers with shroud cover. The gap is still visible where they are not yet fully made up.

Figure 57: Loose Coupler Shrouds, Lesson Learnt [87]

- **Torque bucket damage during tree retrieval**

INCIDENT SUMMARY

The vessel encountered difficulty when pulling the extended well test (EWT) tree from the torque reaction base (TRB). Initial movement of the tree was seen at 10 t overpull (52 t hook load). The hook load was then increased to 57 tonnes and the tree was seen to move upwards approximately 6 inches. At this point the tree stopped moving. Repeated attempts were made to pull the tree by lowering it down and pulling up again and by moving the vessel in different directions to ensure a vertical pull. During this time the hook load was also increased as far as 70 tonnes. The tree continued to stop at 6 inches above the TRB. It was suggested the there could be a snagging point between the tree and the TRB. When the ROV surveyed around the torque buckets on the tree the bucket at the starboard forward side was seen to be hanging lower than the others. Inspection with the ROV showed that one of the beams supporting the bucket had snapped off at the main tree structure, allowing the bucket to move. This was causing it to bind up on the TRB post when the tree was pulled upwards.

IMPACT

Additional time required for pulling the tree resulting in an overall schedule impact

ACTION TAKEN

- The ROV washed off some of the marine growth to allow the problem to be fully inspected.
- Carefully pulled up on the tree with an ROV manipulator supporting the torque bucket to prevent binding.
- Attempted to remove the bucket completely with the ROV so it would not present a dropped object risk. This was not possible as the other strut was pinned in position, so the tree was recovered to surface once the debris cap was in place over the wellhead, and secured with a rope at the moonpool.

IMMEDIATE / ROOT CAUSES

- The damage to the torque bucket was not initially visible due to the large amount of marine growth on the tree.

- The root cause for the failure of the weld onto the tree leg structure will require further investigation.

RECOMMENDATIONS / ACTIONS

- Clean the marine growth from trees around the TRB before pulling so that snag points can be more readily identified.
- More information on the torque frame and TRB would be beneficial.
- Awareness of the weld failure and the possible impacts on Tree 2, which has a similar torque reaction frame design.

PICTURES

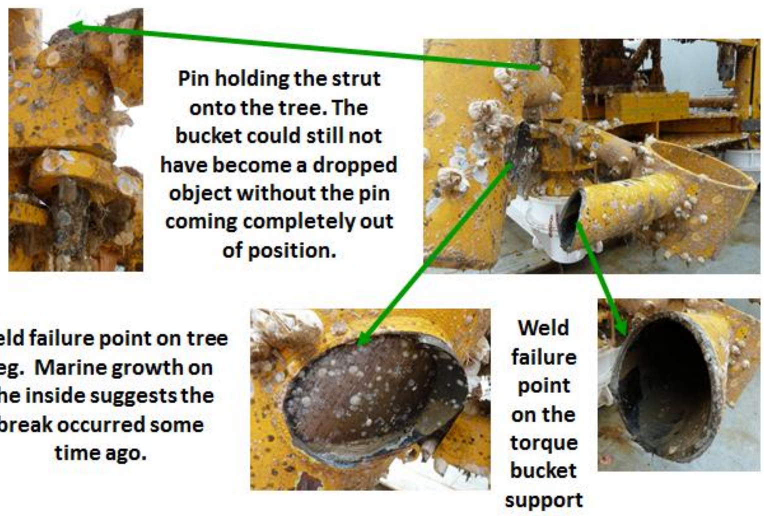


Figure 58: Torque Bucket Damage during Tree Retrieval, Lesson Learnt [88]

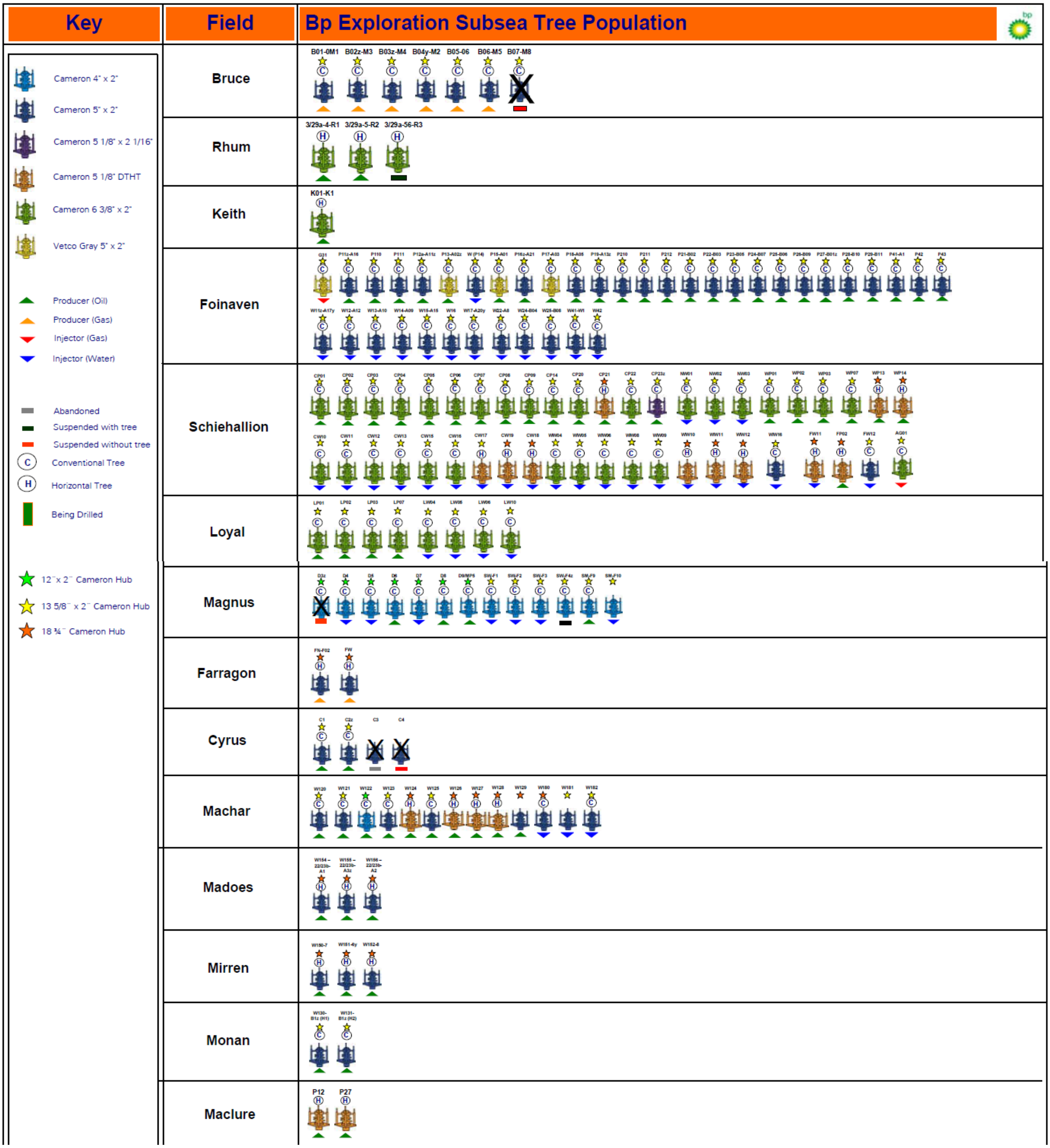
Appendix E – Pressure test and flushing procedure for subsea well

After checking and testing the equipment on surface, a series of testing and preparatory operations are required after the equipment is deployed. A typical sequence of subsea pressure testing and flushing of the WCP, LS and PCH is given here:

- Run WCP with UTH stabbed in
- Leak test UTH chemical stab
- External seal test WCP / XT connection
- Internal seal test WCP / XT connection
- Flush WCP with MEG
- Run LS
- Seal test LLP connector
- Flush LS with MEG
- Subsea ESD test
- Run PCH with tool string
- Seal test ULP connector
- Open XT valve(s) and DHSV
- Equalize pressure across LPIV and UPIV
- Run toolstring into well
- Retrieve toolstring
- Flush LS with MEG
- Pressure test primary barriers LPIV and LIXOV
- Pressure test secondary barriers LOXOV, LCIRC, LCIV and UPIV
- Retrieve PCH and toolstring
- Additional toolstring runs
- Retrieve LS
- Retrieve WCP

The flushing procedure is important since any hydrocarbons leaked to atmosphere has to be reported to the authorities (thus snatched up by media) and can cause big fines and reputational damage even for very small volumes. Operators go to great length to avoid any HC spills.

Appendix F – Subsea Tree Population BP North Sea



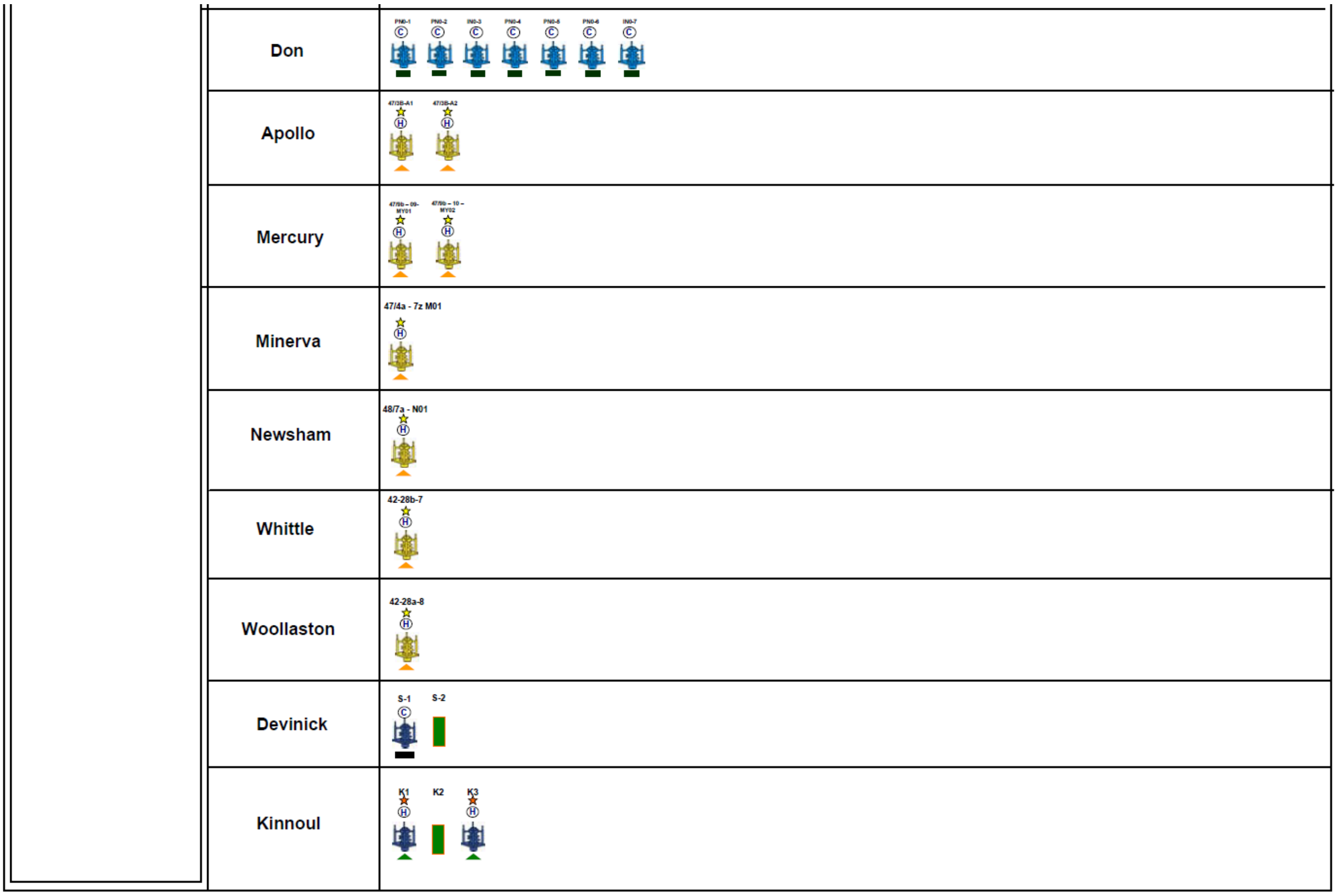


Figure 59 – Subsea Tree Population, BP North Sea [89]

Appendix G – Checklist for Well Site Leaders

WELL SITE LEADERS LWI CHECKLIST

OPERATIONAL DETAILS

WELL NO:	JOB DESCRIPTION:
VESSEL	DATE:
INSTALLATION	WELL SITE LEADERS

DOCUMENTATION

	YES	NO		YES	NO
BP PROGRAMME			Offshore Oil Spill Contingency plan		
ISLAND PROJECT MANUAL			Control of hired and Transportabe equipment UKCS-SOP-005		
FMC OPERATIONAL PROCEDURE			Pressure hose management UKCS-SOP-011		
BRIDGING DOCUMENT			Working with Explosives UKCS-SOP-009		
AKER/JPK PROCEDURE					

SAIL TO LOCATION

	YES	NO
Ensure equipment is spotted on intervention vessel to minamise lifts on location		
Ensure that WSL have relevant ISSOW sign on permission for all Installations/fields to be worked on		
Notify both DCR, Jig Co, Oils & Installation by email, give estimated time of vessel on location.		
Agree what work can or cannot be done while sailing to location.		
Golden rules immersions rolled out		
Review BP Programme with all involved personnel:-		
Check toolstrings with Aker and 3rd party interfaces		
All spares required for forthcoming operations have been checked and are as ordered		
Ensure that all equipment has been check once on the vessel and is fit for purpose		
All equipment, where applicable, has been commissioned and is operational		
Review operational procedures, Island, FMC, Oceaneering, Bridging documents, including emergency and contingency.		
Review Aker procedures, Isolations and well handover with Aker rep, OOE/OTL on installation, BP Subsea, Oceaneering and IOSS.		
Agree permit and isolations required from Aker/JPK/Installation		
ROV to confirm and complete checklist of required equipment to be deployed.		
Well Isolations and handover timings to be agreed with Installation and Aker/JKP rep.		

VESSEL ON LOCATION / ENTER 500m ZONE

	YES	NO
Notify both DCR, Jig Co & Installation that the intervention Vessel has arrived on location.		
Establish and maintain good communications with Installation/Aker Rep		
Conduct Vessel DP trials		
Obtain a permit to enter 500 meter zone to allow the vessel to complete non-intrusive operations		
Conduct as found survey with ROV of site and Vessel DP checks		
HP jet any areas with debris build up around the debris cap and clean post tops, ROV is to remove any marine growth		
Confirm and Record Valve positions		
Confirm with the installation which isolations have been put in place.		
Aker Rep to complete required isolation that are required for well hand over		

WELL HANDOVER INSTALLATION TO BP WSL

	YES	NO
Confirm and receive Well Hand over certificate		
Deploy grease injection refill skid/ROV baskets and concrete mats if required		
Run grease injection refill and Brayco/refill system		
Deploy and install Guide wires/Posts		
ROV/BP subsea rep to coordinate valve movements as per instruction from installation/Aker procedures		

WELL HANDOVER BP WSL TO INSTALLATION

	YES	NO
Ensure that all Xmas tree valves have been integrity tested and isolated are per Aker/JKP procedure		
Recover grease injection refill skid/ROV baskets and concrete mats if required		
Aker/JPK Rep to confirm that integrity tests and isolations are correct to hand well back to Installation, ROV to confirm		
ROV to confirm valve positions as per Aker/JKP procedures and well hand over		
Complete Well hand over certificate and hand well back to installation		
ROV/BP subsea rep to coordinate valve movements as per instruction from installation/Aker procedures to confirm		

DEPARTING LOCATION

	YES	NO
Notify both DCR and Jig co that the Intervention Vessel is departing location with destination details and ETA.		
Sign off all permits prior to departing field		
Inform Installation and Standby vessel that Intervention vessel is departing the field		
Prepare equipment manifests for de-mobilisation		

ON LOCATION DAILY	YES	NO
Ensure Dyce DCR is copied on Daily reports. Jig Co Do NOT require daily reports.	☐	☐
Send DCR POB sheets after crew changes.	☐	☐
Daily Permit Requirements	☐	☐
Ensure that ISSOW permits required are signed on and distrabuted to the tower and bridge	☐	☐
Scheduled Helicopter Flights	☐	☐
If required OILS will let Jigsaw know that a flight is enroute for the Vessel.	☐	☐
Captain or Heli-Admin should update Jig Co with "Souls on Board" info as helicopter departs.	☐	☐
Ensure that all seats that booked by companies are required and not just blocked booked	☐	☐
Unscheduled Flights (ie - flybys, especially short notice ones)		
WSL needs to check with Jig Co that we have adequate rescue performance to cover a helicopter arrival.	☐	☐
Captain or Heli Admin should update Jig Co with "Souls on Board" info as helicopter departs.	☐	☐
Meetings	☐	☐
06:45 and 18:45 Shift change meeting. Expectation around Safety focus, and details of operations, especially "offline" ops.	☐	☐
08:00 Vessel Supervisor meeting. Expectations of supervisors to give overview of all their responsibilities in the next 24hrs	☐	☐
08:30 Vessel morning call with Island/FMC and bp	☐	☐
17:00 Permit meeting and review workscope	☐	☐
Brief for new arrivals after helicopter landing, detail and cover BP expectation on Behaviour (ie as BP OIM on platform).	☐	☐
Record information	☐	☐
Ensure engineer is recording current data daily	☐	☐
Ensure that engineer is recording pitch and roll data	☐	☐
WCP Testing	☐	☐
Record when WCP was lasted tested and and the next test date	☐	☐

Figure 60: Well Site Leaders LWI Checklist [92]

Appendix H – Risk Management Framework

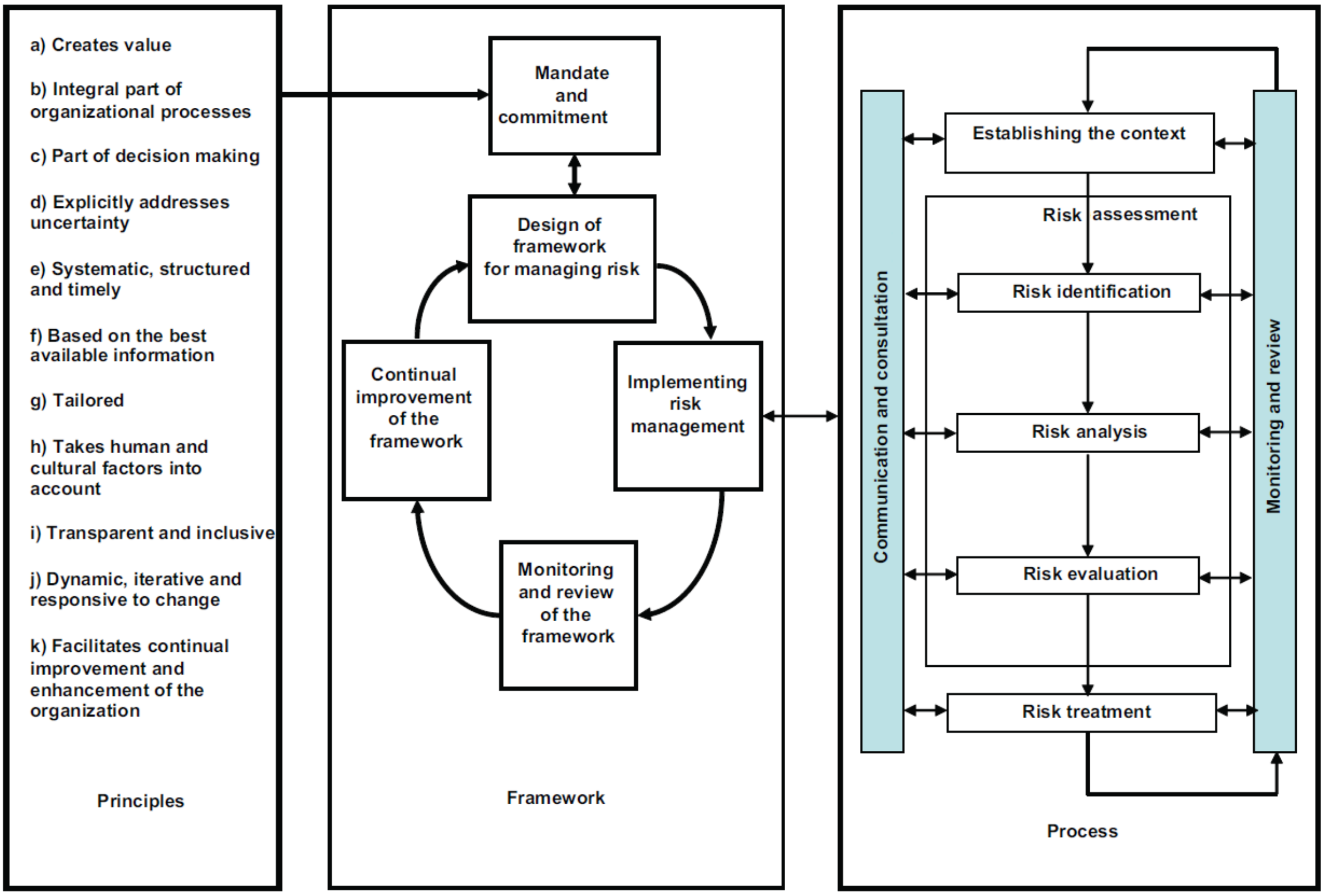


Figure 61: Principles, Framework and Process of ISO Risk Management [78]

Context

The context is established to provide a framework for the risk assessment. Deciding the context is the first step in the risk management process and starting point of integrating goals, its environment, stakeholders and relevant risk criteria. These criterion forms the foundation to evaluate risk significance. The context denotes the assessment's validity, current and future stakeholders, scope and purpose. Why is this risk assessment taking place?

Establishing the context is important to identify and understand where risk can be found and who and what that can be hurt or benefit. The result will entail an overview of who we have to relate to internally and externally and the interests of the parties. This overview will make the foundation for further structuring of the risk identification. Example stakeholders for a BP subsea well intervention are:

Authorities / Contractors / Partners / BP / North Sea / Skarv / Subsea / Well Intervention Dptm.

The present thesis is based on operations performed under UK rules and regulations, while the Skarv development will obviously be subject to Norwegian rules and regulations. Not all lessons learnt can therefore be directly transferred from UK to Norway.

Risk Identification

The organisation should identify sources to risk and areas where they can arise along with possible consequences. Risk identification should also investigate into possible chain reactions. Comprehensive risk identification is crucial as any risk not identified here will not be included in the risk register analysis.

There are many methods meant to identify possible risks, some examples:

- Brain storming
- Cause / Effect diagram
- Flow diagrams
- What if analysis
- Checklists

It is crucial that the risk identification process is systematical to avoid leaving out any risks.

Risk Analysis

The risk analysis is meant to assess the significance of the risks found in the risk analysis, and often ends up with a probability and consequence. Often a risk matrix is used.

The goal is to develop and understand risk and provide input to decision making of whether the risk has to be treated (and how) or not. Usually the analysis includes causes and risk sources, its positive or negative consequences along with probabilities.

A risk analysis can be qualitative (written), quantitative (numbers) or semi-quantitative (mix).

Risk Evaluation

A risk evaluation is performed to decide whether risk treatment is necessary, unnecessary or if a new risk analysis should be conducted. It is done by comparing the risk levels from analysis with the company's risk criterion. When comparing the risk levels with the criterion, sometimes it will be experienced that the criteria were not adequate and identify a need to correct, detail or add criteria. The decision if treatment is necessary will depend on:

- Can the risk have an accumulating effect
- Consequence
- Risk tolerance
- Company resources

If an episode is to be evaluated based on historical events (happened before), there is a need to be cautious since many things might have changed including the risk tolerance level of society, and altered risk levels. It is common to use a risk register for the entire process but especially helpful during risk analysis and evaluation. Risk also needs to be prioritised in this section.

Any decision will usually be affected by extreme negative consequence even if probabilities are extremely low.

Risk Treatment

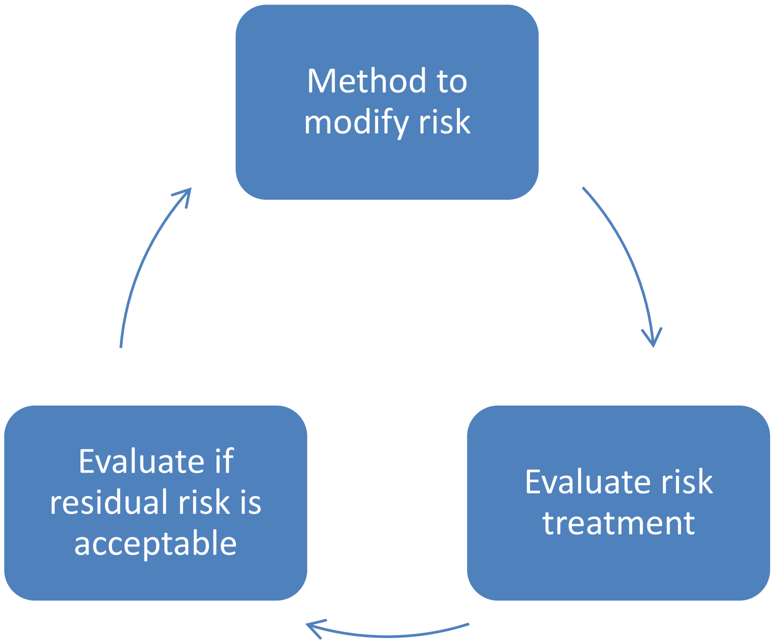


Figure 62: Risk Treatment is a Cyclic Process

Which method is used to modify risk depends on a cost/benefit study. Treatment can affect the risk somewhere else, so all stakeholders needs to be informed. It is also important to be aware that treatment of risk might introduce new risk. We have several possibilities to handle negative risk:

- Reduce the probability of occurrence
- Reduce the consequence
- Accept the risk
- Avoid by excluding activity
- Transfer risk to insurance companies or partners

Of course rules and regulations have to be considered along with internal requisites. It is important to attack the root cause and not symptoms when modifying a risk. The root cause might be found in the culture and attitude of the company. Contingency planning and response plans can potentially reduce the consequence of a risk As Low As Reasonably Possible (ALARP).

Monitor and review

This is where lessons learnt are taken into account. It can also be possible to identify risk trends. Surveillance of the process should be a planned part of the overall risk management process.

Risk Mitigation

Type of Risk Reduction Measure	Examples	Increasing Effectiveness
Elimination	Eliminated by use of substitution (e.g., use of different chemical reactants, cancelling an activity or deferring or limiting an activity to reduce the exposure to hazards)	
Prevention	Prevented at source (e.g., use of alloys that are resistant to corrosion)	
Control	Controlled through design features or administrative procedures (e.g., fire/gas detection and emergency shutdown)	
Mitigation	Mitigated by protection of personnel (e.g., use of Personal Protective Equipment (PPE))	
Emergency Response/ Contingency Plans	Mitigated through effective Emergency Response or Contingency Planning	

Table 12: Risk Reduction Measure Effectiveness [81]

Control types	Examples	Increasing reliability
Passive measures	Preventing a shore tank overflowing during a discharge operation from a ship by installing a tank that it is larger than the ship's capacity.	
Active measures	Preventing a shore tank overflowing during a discharge operation from a ship by installing a high level shutdown system.	
Administrative or procedural controls	Preventing a shore tank overflowing during a discharge operation from a ship by relying on operator monitoring and control.	

Table 13: Control Type Reliability [81]

Appendix I – Risk Assessment Techniques (Norwegian)

The following techniques can be used to aid in the risk management process [90]:

B01 **Brainstorming***

Metode for å stimulere kreativitet. En ide kan gi utgangspunkt for en annen. Mye brukt metode under risiko-identifikasjon.

B02 **Strukturerte og semi-strukturerte intervjuer**

Har likhet med brain storming. Intervju for å få frem ideer hos motparten for så å rangere dem.

B03 **Delphi**

En kombinasjon av en eksperts meninger som støtter identifisering og estimat av sannsynlighet og konsekvens. Rangering foretas av eksperter.

B04 **Check-lists***

Risikoidentifikasjon basert på sjekklister. HAZID (Hazard Identification) hører hjemme her.

B05 **Preliminary Hazard Analysis***

Grovanalyse. Studerer kilder til hendelse og mulige tiltak direkte.

B06 **Hazard and operability studies (HAZOP)***

En metode for å identifisere risiko og tilhørende avvik fra prosessen. Bruker ledeord og parametre. Avvikenes kritikalitet blir vurdert. Benyttes også på gjennomgang av operasjonsprosedyrer.

B07 **Hazard Analysis and Critical Control Points (HACCP)***

Systematisk, proaktiv og forebyggende system for å sikre produktkvalitet, pålitelighet og sikkerhet i prosesser ved å måle at spesielle karakteristikker er innenfor aksepterte grenser. Gir også mulighet til å justere prosessen slik at parametrene forblir innenfor grensene. Ble opprinnelig utviklet for matsikkerhet. Ble grunnlag for ISO 22000.

B08 **Toxicological risk assessment**

Analyse av hvordan et objekt kan bli eksponert for skadelige substanser. Analyse av veiene forplantning kan finne sted. Informasjon om nivået på eksponeringen, hvilken skade og sannsynligheten for at det skjer.

B09 **Structured What If (SWIF)***

Baseres på spørsmålet “Hva hvis?” Egnet til å undersøke svake ledd i prosjekter og lignende. Må følge en struktur, eksempelvis en tidslinje.

B10 **Scenario Analysis**

Mulige fremtidige scenarier blir identifisert ved forestilling eller ekstrapolering. Fastsette risiko til hver scenario.

B11 **Business impact analysis**

En undersøkelse om hvordan risiko for nøkkelelementer kan påvirke organissjonens operasjoner og identifisere tiltak for å håndtere det.

B12 **Root cause analysis**

Analyse av et enkelt tap for å forstå bidragsytende årsaker og for å hindre gjentakelser. Hvilke styringsparametre var på plass (barrierer) og hvordan disse kan forbedres.

B13 **Failure Mode and Effect Analysis (FMEA)***

En metode der alle feilmodi og deres effekter defineres. FMEA finnes i ulike former, for mekaniske komponenter, prosesser, tjenester og programvare. Når man knytter kritikalitet til metoden kalles den for FMECA der "C" står for criticality, basert på sannsynlighet multiplisert med konsekvens.

B14 **Feiltreanalyse***

En teknikk der men begynner med en uønsket hendelse (feil) og analyserer på hvilken måte den kan oppstå. Fremstilles grafisk med "og" og "eller" logiske porter. Når treet er laget, kan man se på måter for å redusere risiko for topphendelsen.

B15 **Hendelsestre***

Grafisk fremstilling av trinnene i en rekke sekvensielle hendelse med tilhørende sannsynligheter for å bestemme sannsynligheten for ulike resultater av utgangshendelsen.

B16 **Årsak og konsekvens analyse**

En kombinasjon av feiltre og hendelsestre analyse som tillater forsinkelser. Både årsaker og konsekvenser av en utgangshendelse betraktes.

B17 **Årsak og effekt analyse**

Også kalt "fiskebensdiagram". Grafisk fremstilling av hvilke effekter som han skape en bestemt årsak. Benytter ofte kategoriene Menneske, Maskin, Material og Metode. Benyttes mye innen kvalitetsforbedring.

B18 **Layers of protection analysis (LOAP)**

Metode for å undersøke om "controls" (styringspunkt, barrierer) er tilstrekkelige. Kalles også "Barriere analyse".

B19 **Beslutningstre**

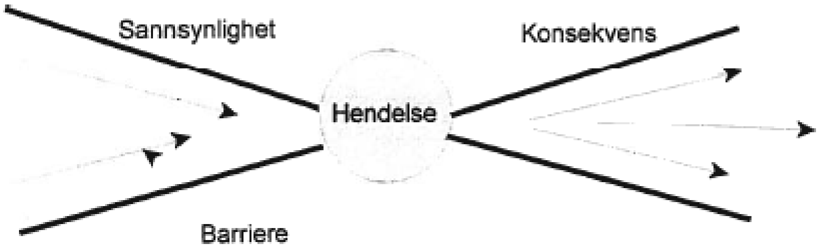
Ligner på feiltre ved at en hendelse eller en beslutning er utgangspunktet og mulige videre beslutninger beskrives i sekvensiell rekkefølge, lik feiltreet. Det kan knyttes sannsynligheter til beslutningene og så kan man velge ønsket beslutnings-serie.

B20 **Human reliability analysis**

Benyttes til å vurdere menneskelige feils effekt på systemer.

B21 **Bow tie analysis**

Et diagram som viser sammenhengen fra risiko til resultat og tilhørende styringsmekanikker. Det er en slags kombinasjon av logikken i et feiltre som analyserer årsak og et hendelsestre som analyserer konsekvenser. Hendelsen er i midten, knuten. Det ser ut som en sløyfe (slips-type) som kalles "bow tie" på engelsk.



B22 **Reliability centered maintenance**

Metode for å identifisere de policies som skal implementeres for å styre feil med tanke på effektivitet, sikkerhet, tilgjengelighet og økonomi for alt utstyr.

B23 **Sneak circuit analysis**

Metode for å identifisere design feil. "Slangen" er latent i systemer og vil ikke uten videre være synlig ved kontroll. Den kan bli aktiv ved tilfeldige hendelser eller ved kombinasjoner av hendelser. Sneak-tilstander kan skape avbrudd og/eller skade.
Et kjent problem ved programvare utvikling.

B24 **Markov analysis**

Markov-analyser er matematiske og beskriver tilstander som endrer seg i komplekse systemer. De kan også benyttes på generasjons-problemer.

B25 **Monte Carlo simulation***

Metoden baserer seg på beskrivelse av usikkerheter med fordelinger som benyttes til å skape tilfeldige tall. Disse benyttes i en matematisk modell, eksempelvis i et regneark. Metoden benyttes i hovedsak til forplantning av en usikkerhet i en analysemodell, og til sannsynlighetsberegning der konvonsjonell analyse ikke fungerer.

B26 **Bayesian statistics and Bayesian nets**

En statistisk metode for å vurdere sannsynlighet basert på tidligere fordelings data.

B27 **FN kurver**

En fremstillingsform av resultater fra undersøkelser der F er frekvens og N et antall involverte. Benyttes ofte ved storulykke analyser der kurvene viser sannsynlighet for et varierende antall N skadede, for eksempel.

B28 **Risiko indekser**

En semi-kvantitativ metode for å sammenligne og rangere ulike risiki. Riskene som sammenlignes kan ha ulike typer kriterier, men kan normeres på denne måten. Det er de enkelte elementene ved risikoen som karaktersettes.

B29 **Konsekvens/sannsynlighets matrise**

Disse er mye benyttet til å fremstille risiko og sammenligne og rangere dem innbyrdes. Metoden forutsetter at sannsynlighet og konsekvens multipliseres. Det er vanlig å benytte farger som grønt, og **rødt** for å markere grenser for akseptable risiko (kriterier).

B30 **Kost/nytte analyse**

Man må alltid ha for øyet at risikostyring og -analyse skal være lønnsomt. Ellers skal ikke tiltak gjennomføres. Kostnadene ved å gjennomføre tiltak må veies mot forventet besparelse eller inntjening.

B31 **Multi-criteria decision analysis**

En metode for å rangere mulige tiltak (opsjoner) for å komme frem til en preferanse blant mange mulig tiltak. Det benyttes en matrise der alle tiltak vurderes etter definerte kriterier slik at man kan summere opp resultatet for hvert mulige tiltak.

Appendix J – Recommended Risk Register Approach for Subsea Well Interventions

A kick-off template for increasing total risk awareness in subsea well intervention operations

S,L and R in the matrix stands for Severity, Likelihood and Risk rating respectively. How these are determined is described in the “Risk Tolerance Matrix” chapter. The Risk Assessment Template excel sheet is included on the attached CD. Red text areas are designated for user input.

Subsea Well Intervention Risk Assessment Template	
RA Title	Fill in your intervention title here
RA description	Describe your intervention here
RA information	This subsea well intervention risk assessment kick off template is meant to provide an overview over what needs to be considered by an intervention engineer prior to mobilizing for operation, and function as a kick-off for the risk register used when planning for a specific well intervention.
Context	Establish Main Context here (Refer to thesis text for context content and guideline)
Context information	It is essential to establish a context to consider which pre-requisites are required for the risk assessment to be valid. The context should be structured such as it includes all elements involved in a subsea well intervention operation, from high level to low level risk, and major accident potential to operational risk levels (which risk assessment pre-requisits are valid, which areas are covered, stakeholders, the involved equipment packages and relevant operations for the risk assessment). In addition to the main Context, sub-contexts need to be established for each main assessment group.

Risk assessment team	Are Folkestad Kile		
Date of risk assessment	01.05.2012	**Estimated authorisation date**	27.06.2012

Use the form below to provide further detail of hazards, consequences, control measures and actions, based on the **HSE Checklist** guideword review, or other **technical or process** prompts that the review team raise. The Group risk matrix should be used for the assessment of risk (refer to GDP 3.1-0001).

Risk Description				Risk before handling			Risk Handling						Residual Risk			Risk after handling
Risk ID	**Risk**	**Cause**	**Risk effect / impact**	**S**	**L**	**R**	**Control Measure**	**Action No.**	**Action**	**Actionee**	**Due date**	**Status**	**S**	**L**	**R**	**Comments**
	Black Swan Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
1	Simultaneous occurrence of major accident elements (to be assessed in the team at irregular intervals)	As specific as possible for as specific measures as possible		A	1	15	Risk level 15 is inserted to illustrate that Black Swan assessments should focus on very high risk incidents.									
Example	Blowout while vessel on fire						Just a spark away for the well intervention on Elgin									

2	Insert other specific hazards															
3																
	Vessel Specific Risk Assessment (awareness)															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
4	Conflict with any vessel specfic context pre-requisites?	As specific as possible for as specific measures as possible					According to different vessel specific risk assessments, and weighted for this specific case									
5	Collision with supply/merchant/fishing/standby ship								OK?							
6	Collision with platform or submersible vessel								Further risk assessment required?							
7	Collision with drifting object								OK?							
8	Skewed weight distribution of deck cargo/ballast/icing															
9	Falling deck cargo															
	Falling crane beams															

	Malfunctioning DP systems (drive off / drift off)															
	Malfunctioning winch															
	Helicopter accident on or close to vessel															
	Hull / Structural failure															
	Fire in living quarters/engine rooms/utility rooms															
	Explosion in engine room and other utility rooms															
	Loss of control during relocation															
	Risk of running aground															
	Insert other project specific vessel hazards															

	Schedule Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	Season Risks	As specific as possible for as specific measures as possible														
	Field schedule collisions with other vessels															
	More / less time needed for operation															
	Late planning and preparations															
	Risked time and cost estimate?															
	Change in scope probable?															
	Consent and permit delays															
	Downtime															
	Insert other project specific hazards															

	Operation Area and Environmental Specific Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	Environmental sensitive area	As specific as possible for as specific measures as possible														
	Equipment specification outside operational limits or below operational needs															
	Fluid spills															
	Hydrocarbon spill / leak															
	Harm to marine life															
	Harm to local flora or fauna															
	Operational window risks (weather, currents, significant wave height)															
	Emissions within tolerance criteria															
	Rig up area clear and ready for intervention operation															
	Insert other specific hazards															

	Operational Activity Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	Barrier status considered for each operational step	As specific as possible for as specific measures as possible					Ref: "Lessons learnt" activities from earlier summaries									
	Major accident potential higher (or lower) than normal?															
	Technical and operational complexity increase															
	H_2S potential															
	Contingency planned if well does not behave as expected															
	Possible interface clashes eliminated															
	Volume control errors															
	Operational changes properly risked?															
	Well Integrity challenges															
	Missing tools															
	Special well circumstances (well history weaknesses)															
	New contractors?															
	New personnel?															
	Insert other specific hazards															

	System and Equipment Specific Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	New or unknown equipment planned for use, prototypes?	As specific as possible for as specific measures as possible					Ref: "Lessons learnt" activities from earlier summaries									
	Equipment compatibilities checked towards other contractor equipment, and towards well conditions (expected fluids)?						Ref: "Lessons learnt" activities from earlier summaries									
	All new equipment properly risked by contractor?															
	WCP (BOP funtions) tested and verified for expected conditions?						Ref: "Lessons learnt" activities from earlier summaries									
	Inadequate shut in capability															
	Missing spares						Ref: "Lessons learnt" activities from earlier summaries									
	ROV capablility for planned tasks						Ref: "Lessons learnt" activities from earlier summaries									
	Line entanglement (umbilical, ROV, etc)						Ref: "Lessons learnt" activities from earlier summaries									
	Clear markings on lines, hoses, outlets and other equipment						Ref: "Lessons learnt" activities from earlier summaries									
	Insert other specific hazards															

	Well Specific Blowout Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	Improper preparation of well intervention in relation to blowout potential	As specific as possible for as specific measures as possible					Normally prepared for the drilling and completion of the well, however, not always ready and updated to present conditions.									
	Blowout contingency in place and known to involved parties?															
	Managable blowout rates?															
	Proper relief well positions established?															
	Potential gas release to sea below vessel															
	Fire or explostion risk due to hydrocarbon release															
	Well killing capability															
	Insert other specific hazards															

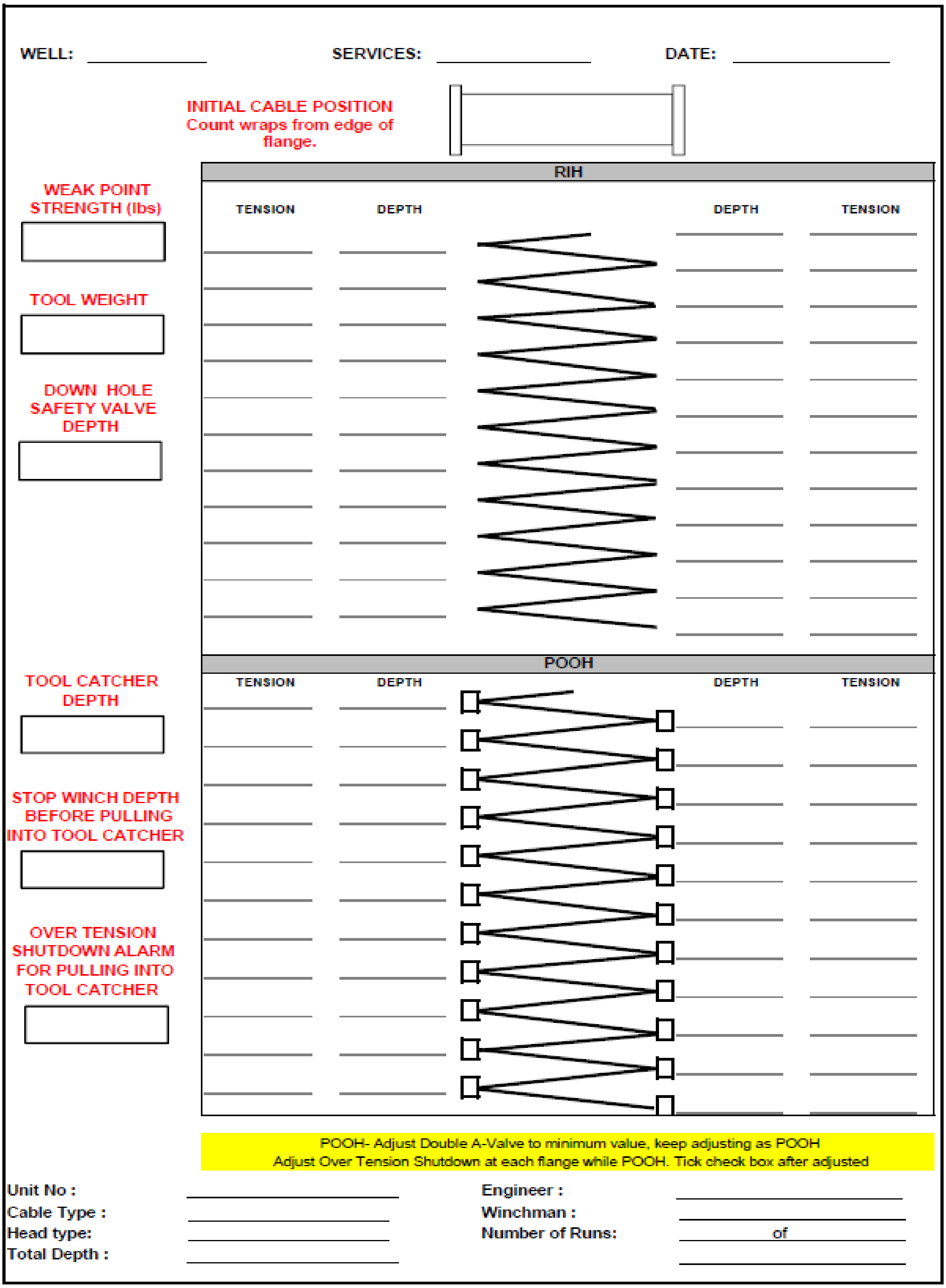
	Program and Procedure Risk Assessment															
	Establish sub-context						Establish Sub-Context here (See thesis text for context content and guideline)									
	The program complies with BP requirements / Program risked?	As specific as possible for as specific measures as possible					Ref: "Lessons learnt" activities from earlier summaries									
	The procedures comply with BP requirements / Procedures risked?						Ref: "Lessons learnt" activities from earlier summaries									
	Unclear scope of work?															
	All new operations covered by risked procedures?															
	Program and procedure complies with regulatory requirements															
	Deviations risked?															
	Any new and untested procedures?															
	Breaks in procedures logic? All interfaces clear?															
	Insert other specific hazards															

Based on this total risk assessment, is a more comprehensive process required, or is risk level tolerable? (if 'Yes' then identify the proposed process to be followed from the list on the right)	YES / NO

Table 14: Risk Assessment Template

Appendix K – Z chart

This Halliburton Z chart can potentially be used for depth control during operations:


WELL: SERVICES: DATE:

INITIAL CABLE POSITION
Count wraps from edge of flange.

WEAK POINT STRENGTH (lbs)

TOOL WEIGHT

DOWN HOLE SAFETY VALVE DEPTH

RIH

TENSION DEPTH DEPTH TENSION

TOOL CATCHER DEPTH

STOP WINCH DEPTH BEFORE PULLING INTO TOOL CATCHER

OVER TENSION SHUTDOWN ALARM FOR PULLING INTO TOOL CATCHER

POOH

TENSION DEPTH DEPTH TENSION

POOH- Adjust Double A-Valve to minimum value, keep adjusting as POOH
Adjust Over Tension Shutdown at each flange while POOH. Tick check box after adjusted

Unit No :
Cable Type :
Head type:
Total Depth :

Engineer :
Winchman :
Number of Runs: of

Table 15: Halliburton Z chart