University of Stavanger

Master Thesis

Study program / Specialization: Master of Science in Petroleum Engineering, Drilling and Well Technology	Spring Semester, 2012 Open
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Title of Thesis:

Risk Based Cost and Duration Estimation of Permanent Plug and Abandonment Operations in Subsea Exploration Wells

Credits (ECTS) : 30

Subject headings: Plug and Abandonment Cost and Duration Estimation Monte Carlo Simulation RiskE Software Drilling Rig and Intervention Vessel	Pages : 68 + 25 pages of enclosure Stavanger, 12- June -2012

Acknowledgement

The most of the work contained in the following master thesis project was accomplished during the fourth semester of Petroleum Engineering Master Program at University of Stavanger. The project was daily supervised by Kjell Kåre Fjelde with all his knowledge, kindness, willingness and support.

I would also like to acknowledge Torbjørn Vrålstad from SINTEF Petroleum Research as my secondary and external supervisor. I wish to thank Per Lund and Øystein Kanestrøm from NCA for releasing data and most importantly sharing the knowledge of P&A operation. I will also thank all the people and organizations which at any level contributed to my work.

Last but not least I acknowledge my parents Gatot Mardianto and Ardini Raksanagara also all my family and friends in Norway and Indonesia for all the help and support during my studies.

Abstract

World wide there are thousands of subsea wells to be abandoned, including the subsea wells in the North Sea. The operation to abandon a well is commonly known as Plug and Abandonment or P&A. Traditionally for offshore subsea wells the Plug and Abandonment operation is done by a semi submersible drilling rig. The cost of such operation for a single well would not be a problem for an operating company, but considering the huge amount of wells that needs to be abandoned new technologies and methods needs to be developed and implemented in the future.

This thesis will discuss the process of a permanent P&A operation in the North Sea for subsea exploration wells. This includes the regulations, technologies, challenges and methods. New technologies of P&A operation such as using intervention vessels for P&A operations will also be explained.

Determining which method to be used in a P&A operation is important. This thesis will demonstrate that by using Monte Carlo simulation one could forecast the cost and duration of a method for P&A operation and compare the results with other methods. In this thesis the cost and duration forecast is done by a Monte Carlo based software called RiskE. This software is developed mainly for drilling activity forecasting, using it for P&A forecasting reveals room for improving the software for P&A operation. Further studies for the simulation input, detailed operations and risk analysis are needed to build a more specific and accurate simulation.

This thesis will also discuss that cost and duration is not the only criteria in choosing what method is used for a P&A operation. Saving the rig time for drilling and completion activity instead of P&A operation and avoiding delay caused by waiting on weather by suspending the well and re-entry in a better weather window with an intervention vessel could be some consideration besides cost and duration. By using semi submersible drilling rigs, intervention vessels and rig chase vessels or combination of them in the P&A operation, different forecast outcome with its advantages could be known and analyzed. Batch P&A operation and factors that affect the cost and duration forecast of a batch P&A operation will also be described.

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List of Abbreviations

P&A	Plug and Abandonment
RLWI	Riserless Wireline Intervention
LWIV	Light Well Intervention Vessel
LWI	Light Well Intervention
IRIS	International Research Institute of Stavanger
NORSOK	Norske Sokkel Standard
UKOOA	United Kingdom Offshore Operators Association, now Oil & Gas UK
WBS	Well Barrier Schematic
WOW	Waiting On Weather
SNS	Southern North Sea
GoM	Gulf of Mexico
IRIS	International Research Institute of Stavanger
SWAT	Suspended Well Abandonment Tool
WASP	Well Abandonment Straddle Packer
WOW	Waiting on Weather
NCS	Norwegian Continental Shelf

1. Introduction

The oil well in any field in the world will experience phases throughout its life. In the life of the well concept the phases are: Planning, Drilling, Completion, Production and Abandonment. Some of the exploration well will not experience the production phase and be abandoned directly. The cause of an abandonment of a well could be due to economical issues, environmental reason, reentry or structural failure of the well or platform.

Every drilled well in the world will one time need to be abandoned. The process is known in the industry as plug and abandonment (P&A). This is a process where the reservoir/pressure-source/well is plugged and sealed and the wellhead is recovered. According to Ian Barclay et al in SPE 100771 paper [1, 14] around 27000 offshore wells are to be abandoned during the span of 2000 to 2010 and in the North Sea alone it shares 12000 of these wells, 7000 wells are from 600 platforms and the rest 5000 are subsea wells shown in **Figure 1**.

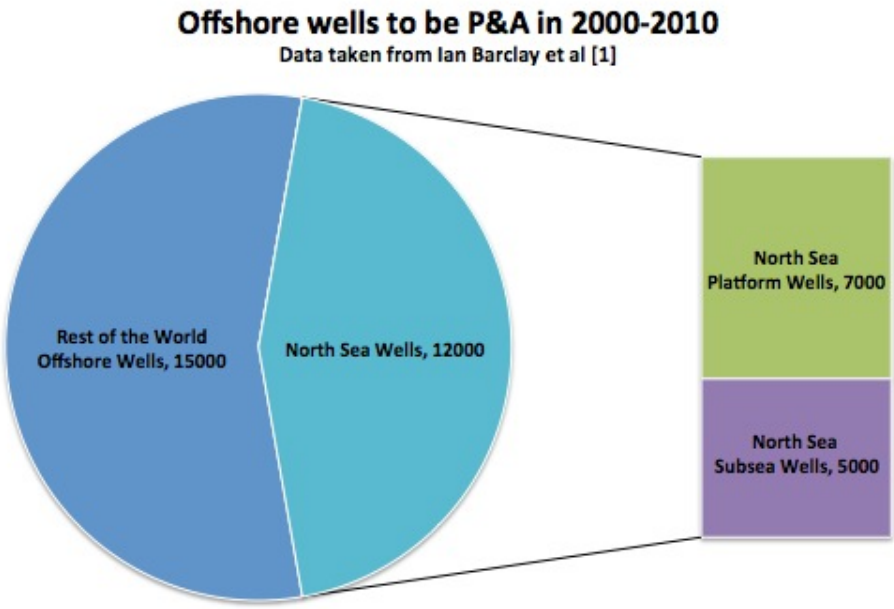


Figure 1. Pie chart of offshore wells to be P&A in 2000-2010

According to a presentation by Subsea P&A AS at P&A forum June 2011 [2] the cost of P&A of 1000 wells using rigs could be 210 billion NOK while using Riserless Wireline Intervention (RLWI) or Light Well Intervention Vessel (LWIV) would be 60 billion NOK. This gives a potential 150 billion NOK saving due to a lower daily rate of the LWIV and releasing more time for more productivity of the rig in drilling operation. Of course, LWIV could not be used for P&A in all cases, but as the technology expands, methods develop and by combining the use of rigs and LWIV in P&A operation significant saving still could be done.

Each operating company that owns the wells has certain ways to P&A the wells safely and efficiently. Besides the well and reservoir condition that will be the base design of the P&A program, regulating bodies has certain requirements regarding the P&A operation that need to be fulfilled as well as internal governing documents. The rules and regulation depends on where the operating company operates, in the North Sea there is the United Kingdom

Offshore Operators Association (UKOOA) for UK sector and Norsk Sokkel Standard (NORSOK) for the Norwegian sector.

It is a tough challenge for the operating company to asses various methods for P&A operation in respect to technical constrains and to estimate cost and duration associated with the different methods. International Research Institute of Stavanger (IRIS) in corporation with an Oil Company has been developing a software called RiskE for risk and uncertainty based cost and duration estimation for drilling operations. The software is based on using Monte Carlo simulation and gives cost and duration histogram and curves as an output.

By studying various P&A methods particularly the use of riserless technologies and batch operations more cost and duration effective P&A operations could be done in the future. Furthermore the advantages of using the riserless technologies and batch operations will be discussed in this thesis. Hence, one of the objective of this thesis is to compare cases of rig-less P&A and Rig-based P&A according to cost and duration with its respective advantage and disadvantages.

To determine the best method and technology used for the P&A operation, cost and duration estimation will be done. In this thesis the estimation will be demonstrated with a probability approach based on Monte Carlo simulation and input distribution. The Monte Carlo simulation will be simulated using RiskE software. The RiskE software was developed for drilling operation. This thesis will propose how the RiskE software could be extended for the P&A phase. This could be an additional tool for the industry to improve in taking decision with respect to find the most cost effective technology for permanent P&A operations.

2. Plug and Abandonment Theory

Plug and abandonment (P&A) operation in a well especially subsea well is an operation that needs detailed planning, careful cost and risk estimation and safety precautions before execution of the operation. Legal documents from regulating bodies must also be followed for the operational process and the final result. P&A operation in the field has different potential scenarios each with different limitations and also different methods for executing.

This chapter will explain the regulations that govern P&A operations in the North Sea, possible P&A scenarios according to NORSOK and limitations of P&A operation in the North Sea and in addition, vessels and new technology that are available for P&A operation will be described.

2.1. Definition of Plug and Abandonment Operations

According to NORSOK D-010 there are two types of P&A, temporary abandonment and permanent abandonment [3]. Temporary abandonment is when the well is abandoned in a way that re-entry is possible after a planned period of abandonment. Permanent abandonment is when the well is abandoned permanently until infinity of time. In this thesis unless it is stated temporary P&A the term P&A refers to permanent plug and abandonment.

The definition of Plug and Abandonment itself is to seal the well with its contained pressure from the surface and recover the structures. There shall be no other obstructions related to drilling and well activities left behind the seafloor/surface [3].

For a subsea well, removing the wellhead is a part of the P&A operation, according to NORSOK regulation subsea wellhead need to be removed 5 meters below seabed [3]. Decommissioning of a steel jacket or platform in a non-subsea well can be considered a P&A operation in later stages. Land rigs have different regulation for decommissioning the surface installation which is not the focus of this thesis.

2.2. Regulations of P&A Operations

The P&A process as mentioned has certain design basis, whether it is the well status, reservoir status, surface facilities, etc. The challenge is to handle these issues but still be inside the boundary of the requirements that regulatory body require. In the North Sea, NORSOK (2004, Norway) and UKOOA (2009, UK) are the guidelines that govern the P&A process.

The goal of all regulations is rather similar with the definition where the objective is to prevent fluid migration from reservoir to the surface and/or also moving between permeable layers underground. In addition, there shall be no trace of drilling and well activities on the seafloor. According to NORSOK D-10 this condition should be achieved in an eternal perspective, i.e. the well barriers should remain intact after any foreseeable chemical and geological process has taken place in time [3].

In a normal P&A operation in Norwegian sector of the North Sea the regulations stated in the NORSOK D-10 is sufficient enough to ensure a safe and successful P&A operation. Nevertheless, each operating company has its own policy and practices that could be stricter regarding the P&A operation which leads to improvement in Health, Safety and Environment (HSE) and also cost efficiency. The practice used by each company must be in compliance with the overall regulations. This nature of oil and gas industry keeps the regulations dynamic and one could also adopt the practices as the new requirements for new regulations.

On the other hand the UKOOA Guidelines for the Suspension and Abandonment of Wells regulations [9] are more specific on the technical aspects and requirements. The interesting part of the UKOOA regulations [9] is in section 7 where 18 special P&A conditions are elaborated and guidelines are given considering aspects such as, high angle or horizontal wells, multilateral wells, liner laps, through tubing, HPHT wells, etc [5].

Barriers, categorization, and design basis are important parts of the regulations for P&A of a subsea well in the North Sea. These topics will be explained furthermore in the section below.

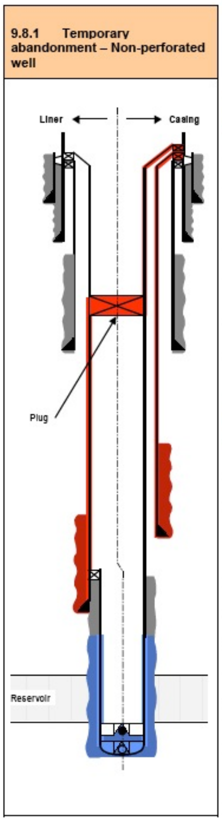
2.2.1. Barriers

The definition of a well barrier is a closed envelope consisting of one or several well barrier elements that prevents flow from a source. A well barrier element itself according to NORSOK is an object that alone cannot prevent flow from one source to another [3].

During the P&A activity and the final result of the abandonment, the barriers must be established. As stated in NORSOK D-010 there shall be at least one well barrier between surface and potential source inflow, unless it is a reservoir (or has a flow potential) in which case two well barriers are required [3].

The two independent barriers are commonly known as primary well barrier and secondary well barrier. Primary barrier by definition is the first barrier to prevent flow and secondary barrier is the second barrier that prevents flow from source. In **Figure 2**, a typical well barrier schematics is shown from NORSOK D-010. It shows the barriers for an openhole non perforated temporary P&A case i.e primary barrier, secondary barrier and well barrier elements.

For the permanent P&A case, the barriers need to be permanent or long lasting. In the NORSOK D-010 permanent well barriers has certain criteria that needs to be fulfilled. Permanent well barriers shall extend across the full section of the well including all annuli and seal both vertically and horizontally [3] as shown in **Figure 3**. By observing the figure it is obvious in the case of plugging the well inside the casing, verification of the cement quality behind the casing is essential to meet the requirements. In a case where the cement behind the casing doesn’t meet the requirement, remedial cement or section milling followed by an openhole cement plug or other methods need to be done to establish the horizontal integrity.



Well barrier elements	See Table	Comments
Primary well barrier, last open hole		
1. Cement plug	24	Shoe track.
2. Casing (liner) cement	22	
3. Casing (reservoir liner)	2	Un-perforated w/2 each float valves.
or		
1. Cement plug	24	Shoe track.
2. Casing cement	22	
3. Reservoir casing	2	Un-perforated w/2 each float valves.
Secondary well barrier, temporary abandonment		
1. Casing	2	
2. Casing cement	22	
3. Cement plug or mechanical plug	24 28	Shallow plug.
or		
1. Casing cement	22	
2. Casing	2	Intermediate
3. Wellhead	5	
4. Casing	2	Production casing.
5. Cement plug or mechanical plug	24 28	Shallow plug.

Figure 2. Well barrier schematic of a temporary abandonment non perforated well [3]

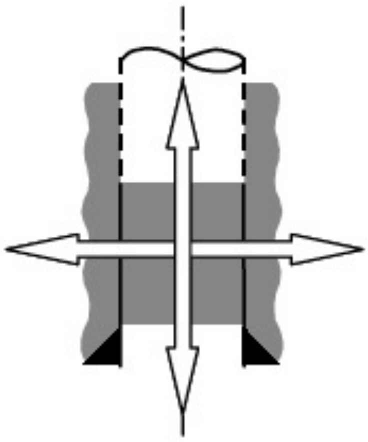


Figure 3. Illustration of the permanent well barrier extending vertically and horizontally [3]

Besides having integrity extending vertically and horizontally, according to the NORSOK D-010, a permanent well barrier material also should have the following properties [3]:

- Impermeable
- Long term integrity
- Non shrinking
- Ductile – non brittile – able to withstand mechanical loads/impact
- Resistance to different chemicals/substances (H_2S, CO_2 and hydrocarbons)
- Wetting, to ensure bonding to steel

The properties listed above are to ensure the safety and the integrity of the barriers after abandonment in the long term. A common well barrier element that is used for the permanent well barrier is cement plug since it fulfills the requirement and it is well proven in the oil industry. Other new technologies for plugging materials are also available such as Sandaband, etc.

In some cases when establishing the permanent barriers, downhole equipment will still be in the hole. These equipments don't need to be removed as long as the well integrity can be verified. In the area where the permanent well barriers will be established, downhole cables or hydraulic lines should be removed since it will be a potential leak path. Hence, there can be a need for pulling the production tubing to have these removed.

According to NORSOK D-010 multiple reservoir sections with the same pressure regime with a natural well barrier in between can be regarded as one reservoir. If there is a potential crossflow and different pressure regimes permanent barriers need to be established in between [3].

After establishing the permanent well barrier, testing needs to be done to verify the quality of the well barrier elements. In the case of using cement plug the guidelines in NORSOK D-010 table 24 needs to be followed. Other well barrier elements should also be verified respective to their criteria; UKOOA also has certain policies regarding requirements and verification of the permanent barriers. This documentation could be found page 9 and 10 in the Guidelines for Suspension and Abandonment released by the UKOOA [9].

2.2.2. Categorization of a P&A Well

The categorization of P&A well is important for assessing the cost and risk of the operation. It could be based on what level of intervention needed, what is the current well status and operation already done, accessibility, etc. For example the North Sea UK regulations UKOOA have provided the following guidelines for the categorization [5] for suspended exploration and appraisal wells P&A, shown in **Table 1** below.

Table 1. UKOOA version of the common categorization system [5]

Category	Definition
1	The well has been sufficiently suspended that final abandonment only requires removal of the wellhead.
2.1	The well has one annulus uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annulus or placing a separate barrier. This type of well may be abandoned with a drilling rig or a light-well intervention vessel.
2.2	The well has two annuli uncemented. Placement of an additional permanent barrier is required to complete the abandonment of the well. This may be done by placing a barrier into the annuli or placing a separate barrier. This type of well may be abandoned with a drilling rig or a light-well intervention vessel.
3	The suspended condition of the well is not suitable for full abandonment without significant intervention. Typically, with current technology, the abandonment program will require a drilling rig to safely effect the operation.
4	Well are placed in this category for several reasons: The downhole status is not known, therefore cannot be categorized. The well is in condition where it is not possible to safely abandon with current technology.

It is also suggested that a full review of the well is made when performing the categorization. A risk assessment should be carried out considering the well status, proposed program and conformability to the regulation [5]. UKOOA also published categorization based of well accessibility shown here in **table 2**.

Table 2. UKOOA version of categorization based on accessibility [5]

Category	Definition
1	Accessible
2	Not accessible because:
2a	On a template with other wells that are developed or planned for development
2b	Less than 50 m from other subsea infrastructure
2c	Within 500 m safety zone of an installation or subsea development
2d	The well has a identifiable problem where the risk associated with abandonment requires additional study
2e	Is deeply buried under seabed

These categorization are just examples of the various categorization of a P&A well. This categorization could be used as a tool in taking decision regarding P&A operation. There will be another example of categorization of P&A well discussed in this thesis in section 2.4.2 and its application regarding the need of new Intervention vessels. In the Norwegian Sector, NORSOK [3] standard does not provide any guidelines or versions of categorization.

2.2.3. Design Basis for a P&A Well

When designing P&A operations, different scenarios could occur depending on the status of the well. There is a low probability for having two identical wells. By assessing known field data and acquiring new data for the purpose of P&A operation, engineers will be able to design a P&A operation with these data as a basis. NORSOK D-010 provides guidelines on which data that should be gathered [3]:

a) Well configuration (original, intermediate and present) including depths and specification of permeable formations, casing strings, primary cement behind casing status, well bores, side-tracks, etc
b) Stratigraphic sequence of each wellbore showing reservoir(s) and information about their current and future production potential, where reservoir fluids and pressures (initial, current and in an eternal perspective) are included.
c) Logs, return, circulation and other data and information from primary cementing operations in the well.
d) Estimated formation fracture gradient.
e) Specific well conditions such as scale build up, casing wear, collapsed casing, fill or similar issues.

Primary cementing as mentioned before could be a part of the permanent barriers. By planning and ensuring the initial drilling and completion design and the quality of primary cementing are good, abandonment process in a later stage could be benefited in many ways. When planning to use cement in a P&A operation, NORSOK D-010 recommend that the planning program should account for uncertainties related to [3]:

a) Downhole placement techniques
b) Minimum volumes required to mix a homogenous slurry

c) Surface volume control
d) Pump efficiency/ -parameters
e) Contamination of fluids
f) Shrinkage of cement

UKOOA provides a questioner for the engineers as a minimum fact data gathering for the planned P&A, this documentation could be found on page 22 and 23 in the Guidelines for Suspension and Abandonment released by the UKOOA [9]. The ultimate goal for the design basis guideline is to ensure that the operator consider the essential data in planning a P&A well.

2.3. P&A Operations Scenario and the Operations Needed

Later in the thesis a comparison of methods for P&A operation of subsea exploration well will be shown. Therefore the knowledge of P&A scenarios and barrier schematic for the different configurations are important. There is never one identical well P&A operation. In order to show the different configurations, the NORSOK D-010 standard presents six general P&A scenarios including temporary abandonment. Four of the scenarios are explained in the following section, the other two; permanent abandonment – multibore with slotted liner/sandscreens and permanent abandonment – slotted liners in multiple reservoirs will not be explained and the barrier schematic could be seen in **Appendix A**.

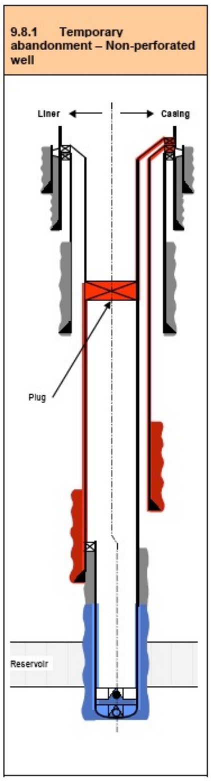
2.3.1. Temporary Abandonment - Non Perforated Well

The temporary abandonment – non perforated well is usually a case in exploration wells when a discovery has been made and there is a need for further well testing and perforation. The well is temporary abandoned while doing other exploration wells in a batch and a later re-entry could be done for the well testing phase. As seen in **Figure 4**, two possible cases of temporary abandonment is shown, i.e. one with production liner and one with production casing. In the figure a vertical center line is used to display both cases

The establishment of the primary barrier for the temporary P&A is already done by the presence of the initial casing cement. The quality is then verified with cement volume return check and logging operation. Ultrasonic Imaging Tool (USIT) and Cement Bond Log (CBL) are also used to verify the quality and presence of cement behind casing. No single method is permitted to be the sole decision maker of the verification.

The secondary barrier seen in the barrier schematic is the cement behind casing, the casing/liner itself and also a shallow set mechanical plug or cement plug. The requirement for these barriers could be seen in **Appendix A**. Mechanical plug are permitted in the temporary abandonment as long as the integrity could be ensured for a period of time equal to a factor of two multiplied with the planned abandonment time.

Temporary abandoned wells usually still have the wellheads or subsea installation such as templates. These should be protected e.g. with respect to fishing activities. A cover net is common to be used when there are such activities. In deep water where fishing activities don't occur the protection are not required.



Well barrier elements	See Table	Comments
Primary well barrier, last open hole		
1. Cement plug	24	Shoe track.
2. Casing (liner) cement	22	
3. Casing (reservoir liner)	2	Un-perforated w/2 each float valves.
or		
1. Cement plug	24	Shoe track.
2. Casing cement	22	
3. Reservoir casing	2	Un-perforated w/2 each float valves.
Secondary well barrier, temporary abandonment		
1. Casing	2	
2. Casing cement	22	
3. Cement plug or mechanical plug	24 28	Shallow plug.
or		
1. Casing cement	22	
2. Casing	2	Intermediate
3. Wellhead	5	
4. Casing	2	Production casing.
5. Cement plug or mechanical plug	24 28	Shallow plug.

Figure 4. Well barrier schematic of a temporary abandonment non perforated well [3]

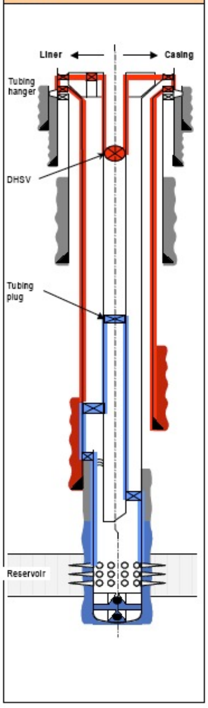
2.3.2. Temporary Abandonment - Perforated Well with BOP or Production Tree Removed

This scenario is another example of a temporary abandonment case; the difference compared with the first case is that well completion is still in place hole as shown in **Figure 5**. The possible scenario presented is a subsea well temporary abandoned by an intervention vessel and one is waiting for a full rig to permanent abandon or make a re-entry for sidetrack by first pulling out the production tubing.

The primary barrier consists of the existing casing cement, production casing, packers (casing, tubing or liner), tubing and tubing plug. The tubing plug could be installed with an intervention vessel using through tubing operation. Secondary barrier consists of the initial equipments such as casing cement, casing, wellhead, completion string/tubing and the downhole safety valve in the closed position. The wellhead also needs to be covered in shallow water with fishing activities.

For re-entry using a semisub, a BOP is installed and the tubing/completion string could be retrieved in a safe manner. The following operation of sidetrack or permanent abandonment then could be commenced.

9.8.2 Temporary abandonment – Perforated well with BOP or production tree removed



Well barrier elements	See Table	Comments
Primary well barrier		
1. Casing (liner) cement	22	
2. Casing (liner)	2	Liner above perforations.
3. Liner top packer	43	
4. Casing	2	Below production packer.
5. Production packer	7	50 m below TOC in casing annulus.
6. Completion string	25	
7. Deep set tubing plug	6	
or,		
1. Casing cement	22	
2. Casing	2	Above perforations.
3. Production packer	7	
4. Completion string	25	
5. Deep set tubing plug	6	
Secondary well barrier, reservoir		
1. Casing cement	22	Above production packer.
2. Casing	2	Common WBE, between liner top packer and production packer.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	
or,		
1. Casing cement	22	Intermediate casing.
2. Casing	2	Intermediate casing.
3. Wellhead	5	
4. Tubing hanger	10	
5. Tubing hanger plug	11	For SSWs.
6. Completion string	25	Down to SCSSV.
7. SCSSV	8	

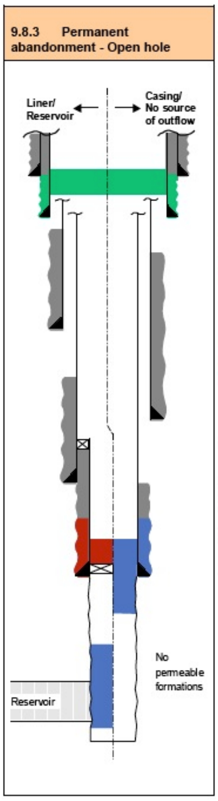
Figure 5. Well barrier schematic of a temporary abandonment perforated well with BOP or production tree removed [3]

2.3.3. Permanent Abandonment - Openhole

Figure 6 below shows a barrier schematic of permanent abandonment in an openhole well with two cases, reservoir present and no reservoir present. This scenario could happen after the drilling of an exploration well.

In the case that there is a reservoir present, the openhole needs to be sealed with two barriers. For permanent abandonment the plug criteria are explained in the barrier section of the thesis. The primary barrier will be set in the reservoir section; bullheading is a common method to establish this. The secondary plug barrier will be at the lowest point of the smallest casing provided that the integrity of the cement behind casing has been verified and the maximum fracture pressure is higher then the contained pressure below the barrier. In the case where a reservoir is not present, one barrier is sufficient.

The other barrier is the surface to open hole barrier. This barrier is mainly to seal shallow sections where pressure is potential and to protect the borehole. For permanent abandonment the wellhead is required to be removed 5 meter below the seabed according to NORSOK – D-010 [3]. Upper section casing are also commonly retrieved shown also in the schematic.



Well barrier elements	See Table	Comments
Primary well barrier		
1. Cement plug	24	Open hole.
or, ("**primary well barrier, last open hole**"):		
1. Casing cement	22	
2. Cement plug	24	Transition plug across casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Cased hole cement plug installed on top of a mechanical plug.
Open hole to surface well barrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes
a. Verification of primary well barrier in the "liner case" to be carried out as detailed in Table 22.
b. The well barrier in deepest casing shoe can for both cases be designed either way, if casing/liner cement is verified and O.K.
c. The secondary well barrier shall as a minimum be positioned at a depth where the estimated formation fracture pressure exceeds the contained pressure below the well barrier.

Figure 6. Well barrier schematic of a permanent abandonment openhole well [3]

2.3.4. Permanent Abandonment - Perforated Well

The permanent abandonment – perforated well scenario shown in **Figure 7** is another possible scenario of a permanent P&A. As seen below there are two specific cases, one is with the tubing and completion still in the well and one without the tubing and completion.

The barrier establishment in the case with the tubing/completion string retrieved is more or less similar to the previous case. The difference is that the cement integrity behind the production casing needs to be verified. This is usually already done in the drilling phase.

For the case with the tubing and completion string in the borehole, the primary barrier is established by bullheading the cement into the formation while verifying the cement quality behind the casing. The secondary barrier is established by perforating the tubing and circulating cement inside the tubing and tubing-casing annulus, the cement behind casing for this section also needs to be verified. The surface to open hole barrier establishment is more or less the same as in the previous scenario.

2.4. P&A Operation Phases and Batch P&A Method

The P&A operation could be divided in phases reflecting the work-scope. Further the phases could be performed using different technologies and methods and be performed at different time. In some cases, multiple wells are in a need for P&A at the same time. These wells could be categorized based on which P&A operation phase that is to be completed. This categorization could then be used as one of the tools to plan the P&A operations in a more cost efficient manner. Usually in this case batch P&A is performed. These topics will be explained in the following section.

2.4.1. P&A Operations Phase

According to UKOOA P&A guidelines the abandonment of any well could be divided into three phases that reflects the work-scope, equipment required, and/or the discrete timing of the different phases of work [5]. The ultimate objective is to simplify the operations and generate cost and duration estimation. Shown here below is the different phase commonly used stated in UKOOA [5].

- **Phase 1 – Reservoir Abandonment**

Primary and secondary permanent barriers set to isolate all reservoir producing or injecting zones. The tubing may be left in place, partly or fully retrieved. The phase is complete when the reservoir is fully isolated from the wellbore. [5]

- **Phase 2 – Intermediate Abandonment**

Includes: isolating liners, milling and retrieving casing, and setting barriers intermediate barriers to isolate potential hydrocarbon or water-bearing permeable zones. Near surface cement may also be installed. The tubing may be partly retrieved, if not already performed in Phase 1. Complete when no further plugging is required. [5]

- **Phase 3 – Wellhead and Conductor Removal**

Includes retrieval of wellhead, conductor, shallow cuts of casing string and cement filling of craters. Complete when no further operations are required for the well. [5]

2.4.2. Batch P&A Method

In a field with multiple wells ready for P&A operation batch P&A is usually performed. This section will explain how the batch P&A operation is designed with respect to the technical aspects. The cost and risk issues will not be explained in detail.

One example case of batch P&A is that the operating company has a field or multiple fields consisting of a number of wells that need to be abandoned. These wells have different complexity and characteristics. Then the operator needs to group the wells according to the complexity/work type, the grouping enables engineers to design an operation plan for group of wells. This alongside with cost and risk factors will improve the efficiency of the P&A operation.

Another case of batch P&A is when an operator or group of operators plans multiple well exploration program. The wells in an exploration program are usually plugged and abandoned permanently after the drilling, logging and well testing. For a single exploration well the rig usually performs the P&A. For a multiple exploration program, the rig time is better to be used for drilling rather than P&A from a cost efficiency point of view. Hence, it could be better to leave the plugging of these wells to an intervention vessel which could perform this in a very cost effective manner.

UKOOA released a guideline for categorizing the permanent P&A of a well based on its complexity. Reflecting the complexity of abandonment a digit from 0 to 4 is chosen for each of the three phases in section 2.4.1., according to the following table:

Table 3. UKOOA version of Permanent P&A categorization based on complexity [5]

Type 0	**No work required** – A phase or phases of abandonment may already have been completed
Type 1	**Simple Rig-less Abandonment** – Using wireline, pumping, crane, jacks. Subsea wells will use Heavy Duty Well Intervention Vessel with Riser
Type 2	**Complex Rig-less Abandonment** – Using CT, HWU, wireline, pumping, crane, jacks. Subsea wells will use Heavy Duty Well Intervention Vessel with Riser
Type 3	**Simple Rig –based Abandonment** – Requiring retrieval of tubing and casing
Type 4	**Complex Rig-based Abandonment** – May have poor access and poor cement requiring retrieval of tubing and casing, milling and cement repairs

UKOOA also released a guideline for assessing the well type for each phase (table 3.1, 3.2 and 3.3) and it could be found on page 19-21 in the Guidelines on Well Abandonment Cost Estimation [5]. After assessing the particular well data for categorization then it could be summarized into a matrix shown in **Table 4**[5].

An example well BANDUNG-32-1, a perforated subsea exploration well was suspended by a rig. The drilling rig has performed the reservoir abandonment and the tubing had been left in the well. There was bad cement behind the casing and there was a need for section milling. The wellhead was still on the seabed and there is a need for a permanent abandonment operation. The possible well classification matrix is as follow and the P&A Code will be **SS 0/4/1**.

Table 4. Complexity Matrix Single Exploration Well Example Case BANDUNG-32-1

BANDUNG – Well 32/P-01 Single Exploration Well Offshore Subsea			Abandonment Complexity				
			Type 0 No work Required	Type 1 Simple Rig-less	Type 2 Complex Rig-less	Type 3 Simple Rig-based	Type 4 Complex Rig based
Phase	1	Reservoir Abandonment	X				
	2	Intermediete Abandonment					X
	3	Wellhead Conductor Removal		X			

In the case of planning batch P&A, the matrix will be used as a tool to know what are the technologies and methods required for the particular field/platform. The matrix will summarize the complexity of the field/platform after each individual well has been assessed. Here below is an example of the matrix of a subsea field exploration project with a total of 10 wells.

Table 5. Complexity Matrix Subsea Exploration Example Case BANDUNG-32 Field

BANDUNG – 32 Field Subsea Exploration Project Offshore Subsea			Abandonment Complexity				
			Type 0 No work Required	Type 1 Simple Rig-less	Type 2 Complex Rig-less	Type 3 Simple Rig-based	Type 4 Complex Rig based
Phase	1	Reservoir Abandonment	5		5		
	2	Intermediete Abandonment			7		3
	3	Wellhead Conductor Removal		10			

From the table above it is easily seen how the complexity of the P&A operation will be in that particular case. The further planning for batch operations will be much easier by knowing this.

One could commence the operations above in a more cost effective manner by using the batch method using batch method by Type 2 vessel for the 12 wells for phase 1 and 2 while using the full rig for the 3 wells for phase 2 and followed by type 1 vessel to finish all wellhead and conductor removal. On the other hand the cost of doing it with one method will be much larger if the 25 operations with full rig size handle it.

From a technical point of view the batch method is an efficient way to P&A multiple wells by using the technology needed for that particular operation. More cost effective vessels can then perform these operations in series. The experience of performing many operations may also improve the work performance and reduce the operating time. Expensive rig time can be used to drill new wells instead. Later in this thesis, this batch method will also be analyzed from a risk based cost and duration point of view.

2.5. Challenges of P&A Operations in North Sea

The geographical location of oil and gas industry hugely affects the characteristics of the operation. In this section several important factors that impact the characteristics of oil and gas operations generally, and P&A specifically in the North Sea will be briefly discussed. These factors are challenges when planning P&A operations. The way these are handled will have direct impact on the efficiency of the operations.

2.5.1. Weather

The weather is a huge challenge for the well operations in the Norwegian Continental Shelf. Logistics, mobilization, operation, equipment limitation, and much more depend on the weather conditions. While performing well operation, harsh condition of the weather could force delays in the operation, this is also known as Waiting On Weather (WOW).

For drilling or urgent logistics situation, WOW is something that cannot be avoided. This is because the operation needs to continue as soon as there is a time period of good weather conditions or also known as weather window. Different method of conveyance e.g. semi submersible rig, intervention vessel or rig chase vessel might not have the same operational capacity with respect to the weather conditions.

On the other hand, for P&A operations using vessels after suspending the drilling, WOW probability could be reduced by planning the time of the P&A operation in a specific time throughout the year. This time is usually in summer when the significant wave height is lower with a low probability of occurring. Wave height is one of the main reasons for WOW due to its direct impact to heave limitation of equipments. Here below in **Figure 7** is an example of metocean data of significant wave height and its probability of existence throughout the year for an unnamed field in the North Sea.

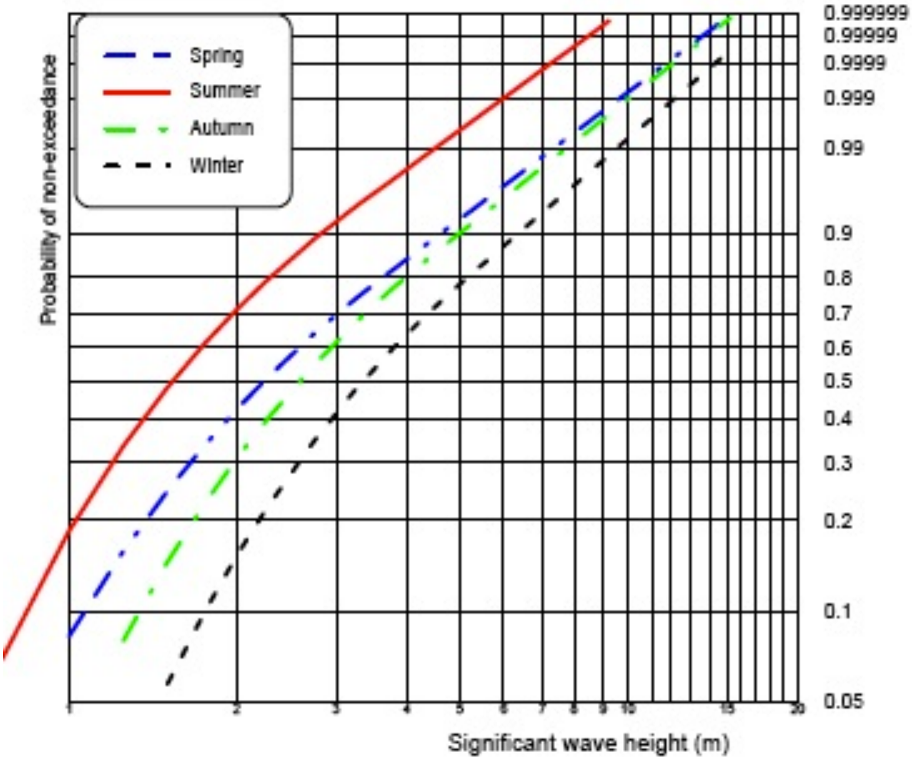


Figure 7. Example of metocean data of significant wave height probability of existence in the NCS [15]

By analyzing this and other types of data provided by the weather information provider, oil companies could plan P&A operation in the time period with the most favorable weather conditions. A simple example using the plot above is if the significant wave height tolerance of a vessel is 7 m, then commencing the operation at the area in winter could result in a 10% WOW probability. On the other hand commencing it in summer will result in 0.01% WOW probability.

2.5.2. Cost

The relatively high cost of oil and gas operation in the North Sea is one of the challenges for field operator when planning P&A operation. Careful planning is needed to be prepared for emergency situations, contingency plans, WOW scenarios, etc. A simple operation could be a train wreck of events that can evolve into a huge financial disaster for the operator if not planned carefully.

A study was performed by Halliburton to compare the well service operation costs between Southern North Sea (SNS) and Gulf of Mexico (GoM), this was presented by Tom Leeson at SPE's 3rd European Abandonment Seminar 29th of March 2011. It was also discussed in a master thesis written by Fredrik Birkeland in 2011 [10]. This section is to some extent based on those publications.

The comparison project investigated 12 wells in SNS and GoM that were conducting P&A activities. These wells had similar water depth and well configurations. It was found that the possible cost differential drivers were [10]:

- Legislation and regulatory standards
- Operational duration

- Well service costs
- Support costs

The investigation also showed that the average operational duration of a well in the GoM was 275 hrs while a well in SNS took 284 hrs in average. Besides the duration, the cost related to the well services were different and in favor of GOM. The well service cost covers [10]:

- Well engineering
- Pumping and cementing services
- WL services
- Bridge plugs, tubing punches and cutters
- Tension cables
- Cement, fluids and viscous reactive pills
- Abrasive water-jet multiple casing cutting
- Multi-skilled crews and supervision

Because of the differences of the cost related to these activities, the nature of the spread rate for a typical P&A activity would differ between GoM and SNS. According to the thesis of Fredrik Birkeland [10], the spread rate of well service in SNS is 1.83 times of the spread rate for a well in GoM. The P&A campaign in the GoM started much earlier than in the SNS, this results in a more mature market and a more competitive environment, hence a lower spread rate cost [10].

Due to this relatively higher cost of P&A in the North Sea, planning and approval of a P&A campaign could be a challenge. By the end of the day oil companies and the government expects to save money for investment in exploration and production activities and also protect the use of tax money.

2.5.3. Subsea Wells

Subsea wells present several challenges for the operator when planning P&A operation. The nature of subsea wells makes both the costs higher and put more demand on equipment required. Several characteristics that could present challenges are:

- Accessibility of the wellhead

  For a subsea well, it is not possible for the field workers to have direct access to the well. The nature of subsea well that lies in the seabed prevents direct access of field workers to the well. This expose the planners to prepare all the possible scenarios and equipment needed. The field operators can only access the well remotely using ROV and other manipulators. These ROV and manipulators need to be prepared before the job. A change from the planned operation, a tool or ROV malfunction will lead to retrieving them to the surface or that a contingency plan has to be performed. This will cause a delay and added cost to the operation.

  The use of ROV and manipulators also has limited access to manipulate the well compared to surface wellhead. Deep-water divers are sometimes used to improve the accessibility of downhole equipments, but this will cause added risk and hazard of the operation.

- Subsea equipment design
  Related to the first point, the subsea installation needs to be as accessible even though the operation will be conducted by ROV. This will add another design factor for the subsea engineer. The subsea installation needs to be as simple as possible to access and operate while maintaining the redundancy and reliability. This is important since conducting any operation/repairs will cost more than for a non-subsea well.

  The special design and equipment for subsea installation will result in an extra cost for the oil company to build and maintain. A P&A operation for a subsea well will also will be affected because the equipment used need to be designed for subsea operation and compatible with the existing systems. The effects will be more risks in terms of delays as mention before and the cost of providing the necessary subsea P&A equipment.

- Weather dependent
  Weather will be a big challenge in a subsea well operation compared to a platform well or a shallow subsea well using jackup rig to operate. To access the well a semisub rig or vessel will locate itself above the subsea well and maintain constant position with the wellhead with its mooring system and/or dynamic positioning system. External forces such as wind and wave will affect its position until a certain limit where the operation cannot be preceded due to technical limitation. Waiting on weather will be a usual procedure and add more cost and time delay. These problems will not occur in a non-subsea well or for a jackup rig where the rig/platform is firmly placed relatively to the wellhead and external forces can be neglected.

- Subsea well control system
  Well control must be maintained all the time in drilling or intervention operation of a subsea well. Maintaining well control and fast response in a critical situation for a subsea well requires advanced equipments and procedures.

  For example a particular semi submersible drilling rig will have a BOP as the secondary barrier and drilling fluid as the primary barrier. In a situation where the BOP needs to be activated the main device is to close the BOP with the surface accumulator and one separate backup system. In the case where the rig is drifting due to emergency, another backup system will trigger the BOP to close due to a lost of hydraulic pressure when shearing the hydraulic lines in the riser. In a case where the rig was abandoned before the BOP was closed, a remote system could close the BOP with electric telemetry from a vessel or another rig nearby. The final backup plan if all system fail is by manually stab in the closing system of the BOP with ROV hydraulic pressure.

  This is just an example of the well control system of a semi submersible drilling rig. For intervention vessel a specific well control system are is also used. Providing this system with the equipments and procedures will add additional cost and risk to the operation.

3. Vessel Technology for P&A Operations

This section will describe new vessels technologies relevant to subsea offshore P&A operation that can be used for obtaining more cost effective operations. A recent study by the UKOOA explains an interesting fact about the technology needed for the P&A operation [6]. This gives an overview of the number of wells that has to be plugged using different technologies.

The study was commenced by taking samples of subsea wells which were considered representative in size to produce meaningful results. The subsea wells were sorted into 5 groups similar to the grouping in section 2.4.2. Shown in **Table 6,** is the well grouping, the percentage values and numbers could be seen in page 15 of the UK North Sea Well Abandonment Study [6].

Table 6. UKOOA Research Sample Categorization on Subsea Well P&A Technology Need [6]

Group 1	**Group 2**	**Group 3**	**Group 4**	**Group 5**
Rig required. Complex/ challenging abandonment	Pulling entire completion necessary. Assume rig required. Maybe rigless in the future	Partial lifting completion necessary. Assume rig required. Maybe rigless in the future	Rigless. Simple through tubing; perforate, cement, <45 deg.	WASP/SWAT (explained in section 3.4.2.). Plugged wellbore. Requiring annulus plugs.

The interesting part of the study by UKOOA is group 2 and 3 that currently need to be abandoned by a full rig. In the future, these could be abandoned using a rigless approach i.e. intervention vessel. This could be a significant cost saving while focusing the available rigs to do exploration and drilling related operations. According to the study, the challenge of technology advancement lays on the number of small development rather then one large breakthrough [6]. Here below are the possible advances according to UKOOA[6]:

- Preventing control lines/cables from providing a leak path, (leaving control lines/cables insitu, stripped of any external sheath, filled with resin, etc)
- Setting plugs below the packer, without removing completion/packer
- Using alternative plug material to shorten required plug height
- More use of coiled tubing for various downhole operations
- Enhanced explosive/knife/abrasive jet cutting at extended depth
- Use of logging tools to enhance understanding of annular conditions, etc to facilitate easier/optimized plug placement/verification
- Improved downhole tools for combined operations, bridge-plug, scraper/stinger, etc
- Pump down tools for achieving well control/cement plug support
- Improved method for determining leak rate and location in completions, thereby enabling use of the tubing for cement plug placement in less severe cases
- Improved remedial cement techniques in the event of well pressures resulting from poor cement operations, or verification failure of abandonment plugs
- Enhanced techniques for verification of mud/oil removal cleanliness

- Centralization of existing completions/tubing to enhance circumferential placement of cement plugs downhole, particularly in high angle wells
- Treatment of scale problems

By improving the technology and its reliability P&A operations for group 2 and 3 could be done by vessels and a potential large number of the subsea wells could be abandoned without using a drilling rig. The drilling rig on the other hand could be used for their main purpose which is drilling and completion. Hence, the availability of drilling rigs will increase and the cost of drilling will be reduced and the number of exploration/production drilling also will be increased.

Further in this section new vessel technologies will be discussed briefly. These technologies are chosen based on the successful deployment track record in the North Sea and used as a base for the cases constructed in this thesis.

3.1. Pipe Pulling and Handling Equipment for Intervention Vessels

A reliable pipe handling and pulling equipment tools installed on an intervention vessel could be a cost and time saving solution for many subsea P&A wells. This is due to the number of wells that need tubing pulling for intermediate abandonment; a costly semisub rig usually performs this operation.

Pipe pulling and handling equipment technology to be installed on vessels is available in the market but unpopular to be used by the operating company since it is a quite new technology. Encouragement by the government regulator to use this technology may be seen as a way to start using the technologies to save tax money in P&A operation since it has a lower day cost. It could also free more rig time to do exploration/production drilling.

According to NCA publications the pipe pulling and handling vessel equipment typically includes [2]:

- Pipe rack
- Drill pipe feeder
- Drill pipe and/or casing gripper for deck crane
- False rotary (non-rotatable) mounted on moon pool door
- Iron roughneck
- Top drive installed for pipe-handling
- BX elevator, insert bushings, remote operated slips, manual slips, rig tongs, bails and pick up elevator

3.2. Abrasive Sand Cutting

The abrasive sand cutting technology is a method for cutting multiple casing strings in one operation. This is one method in accordance to Norwegian regulation to retrieve oil and gas activity remaining 5 m below the seabed without an explosive method. The method of using abrasive sand cutting has some similarities with sand blasting.

The technology has been developed since 2001 and cut tests were performed in 2002 on Ekofisk [7]. After 8 years, over 400 conductors have been cut and this technology has proven to be reliable for subsea well severance [7]. The abrasive sand cutting method is performed from an offshore construction/intervention vessel crane which is heave compensated. The cutting nozzle as a sand blaster is combined with the subsea wellhead picker to achieve proper cutting depth and a method to lift the wellhead.

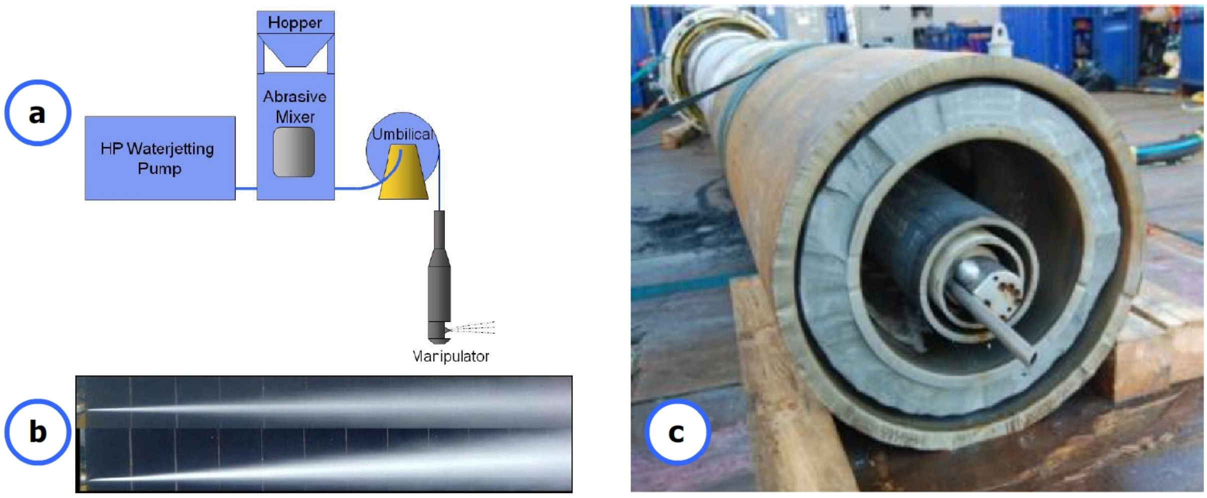


Figure 8. Abrasive Sand Cutting [7]

The configuration of the surface equipment is shown in **Figure 8.a**, the principles of this method is to pressurize water to 60 MPa and 120 MPa while adding abrasive particles and pump the slurry though a nozzle **Figure 8.b** which creates high kinetic energy and according to SPE 148859, this method is proven to cut multi string from 7" casings all the way to a 36" conductor shown in **Figure 8.c** [7]. This technology is also commercially known as Internal Multi-string Cutting Tool (IMCT).

3.3. Subsea Wellhead Picker

The Subsea Wellhead Picker (WHP) is used in conjunction with the IMCT explained in the previous section. This is a reliable device for the phase 3 of the P&A operation which is wellhead removal. With these tools conductor cutting and wellhead removal could be done in one deployment. Since deployed in 2008, this approach can save up to 60% in phase 3 abandonment costs and three to six days of rig spread time [8]. Here below is shown in **Figure 9** the subsea wellhead picker by NCA.

Figure 9. Wellhead Picker (WHP) deployed by NCA [8]

The operation starts with cleaning/drifting the wellhead using a cleaning tool and this operation is assisted by an ROV. After the area data is verified the WHP with the IMCT below is deployed. The IMCT is then stabbed into the wellhead with the ROV and the WHP connector is lowered onto the wellhead supported by the ROV. A pull test is then performed to verify the connection after the placement of the WHP to the wellhead.

The cutting operation explained in previous section is then commenced. Once the cut is done, the heave compensated crane is then used to break the suction between the conductor and environment. This operation is monitored by the ROV to make sure the WHP is still latched onto the wellhead. Furthermore the WHP then recover the wellhead and conductor all together to the deck of the service vessel. The WHP is then disconnected with the wellhead and ready to be deployed to another well.

The advantages of the subsea wellhead picker and IMCT according to NCA publications are [2]:

- Combined tool for cutting and removal of subsea wellheads
- Enables removal of subsea wellheads by use of a simple vessel
- Wellhead is severed and lifted in one single deployment
- No need to relocate vessel during the operation
- No need for marine riser or drill pipe
- Environmentally safe – no use of explosives
- Can be used on single wellheads or on wellheads installed on templates
- Clean cuts for easy recovery of the wellhead and conductor

3.4. Annular Cementing Tools

3.4.1. Cementing Adaptor Tool – One Annulus Cementing

Cementing Adaptor Tool or CAT [2] is a tool under development, it is deployed from an intervention vessel that enables the casing and annulus to be circulated and cemented without the need of a riser. This method is suitable to plug a section with bad cement.

The process starts with selective perforation in the casing to the annulus and seal the ports in between in the stinger inside with temporary packers. This circulation route enables cleaning the annulus, furthermore displace with better cement. The operation will be conducted according to NORSOK D-010 and PSA guidelines.

3.4.2. Well Abandonment Straddle Packer (WASP/SWAT) – Multiple Annuli Cementing

The Well abandonment Straddle Packer has more or less the same function as the Cement Adaptor Tool and could be deployed from an intervention vessel. The advantage with this method is that it enables multiple annuli to be circulated, cleaned and cement plugged. The method also enables the plug to be pressure tested separately. The tool consists of two inflatable packers and two pair of perforation guns for perforating two annuli.

The process starts with the sealing off the wellbore and perforation of the first annuli between the packers and below the bottom packer. These two areas are communicated to the surface from different paths hence creating a circulation path through the annuli. This circulation path is then used to plug the annuli and later to be pressure tested. The second annulus is then perforated through the existing cement with a more powerfull perforation gun. Shown here below in **Figure 10** is the schematic of the WASP by Baker Hughes [2].

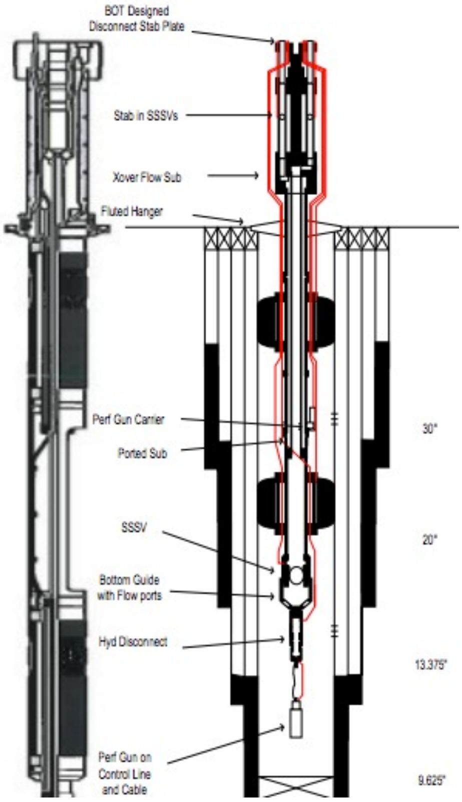


Figure 10. Well Abandonment Straddle Packer (WASP) [2]

4. Concept Application of RiskE Software in P&A Operation

This section will briefly explain the development, use and methodology of the RiskE software. The RiskE software has been developed to strengthen the application of probabilistic well construction cost and duration estimation within drilling operations [11]. International Research Institute of Stavanger (IRIS) developed this software upon request and funding by ENI E&P and support by ProEnergy.

This section is to a large extent based on SPE paper 121837 titled "An Innovative Tool on a Probabilistic Approach Related to the Well Construction Costs and Times Estimation" [11] and RiskE – Software User Manual by IRIS [12]. A part of this section will also show the basic metodology used in the RiskE software by implementing simple methods using Matlab.

Later in this thesis, this drilling cost and duration estimation software will be used to simulate P&A cases. There will be assumptions and possibility of inaccuracy in the result due to the unusual use of the software. But this will result in a feedback to the software developers of the RiskE and give advices on how the software could be extended for use in P&A operations.

4.1. Introduction to RiskE Software

When oil companies are applying for an Authorization for Expenditure (AFE) approval from the regulators, probabilistic well cost estimates is a requirement. The common used method is through a deterministic approach relying mostly on historical data and trends. This practice of relying on "single values" tend to distract the Drilling Engineer from thinking on the actuals risks which could be likely occur in the project [11].

However, the traditional method provides quick results which are easy to communicate. But on the other hand just relying on historical data and previous trends will not represent the actual risk and uncertainties of the current project. For example a field that has been drilled many times successfully all the time does not provide a guarantee for having a 100% success probability in the future. The possible occurrences of undesired events each having different probability and impact have to be considered when evaluating a project [11].

According to Merlo et al. [11], a proper well construction cost and duration analysis tool will improve the basis for the decision-making of the well planning phase. Furthe, it needs to have the following capabilities:

- Systematization of all the available information;
- Quantifying well construction cost and duration;
- Comparing different solutions for construction of a well;
- Creating nuanced cost and duration pictures based on well-specific input parameter values;
- Pinpointing the most critical operations affecting well construction cost and duration uncertainties;
- Reflecting the implementation of cost and duration reducing measures.

As explained before a team in IRIS then developed the RiskE software with support from ENI E&P and ProEnergy. The result was a user friendly, easy to use and effective software that performs the probabilistic cost and duration risk analysis and systemizes the corresponding workflow. The conclusion as by Merlo et al. [11] is that the RiskE software is a tool for the Drilling Engineers to:

- Perform a quantitative risk analysis;
- Calculate risked cost and duration estimation;
- Identify operations which mostly affect drilling uncertainties;
- Evaluate and select alternative technical solutions;
- Prepare prevention and mitigation plans for the reduction of both duration and cost.

4.2. Basic Methodology Used in RiskE Software

RiskE software uses a probabilistic approach to estimate well cost and duration. This is effective in reflecting the uniqueness of each single well construction. Each specific event in a well construction process has different uncertainties in the cost and duration. Therefore the final well cost and total duration are also uncertain and cannot be expressed with a single value [11].

To represent the large uncertainties involved in the analysis, a stochastic approach is done using Monte Carlo simulations. Further details related to this will be explained later. The Drilling Engineers will also build an operation plan with events according to the program. Although this involves large uncertainties, the software allows Drilling Engineers to input the probabilities for different undesirable events and specify the impact they can have. The stochastic modeling, undesirable event and operation plan input will allow the user to obtain the probability distribution of the final well cost and duration from the software.

According to Merlo et al. [11], the main benefits of this methodology are [11]:

- More effective work process, through:
    - Systematized expert input;
    - “Easy to do” in-house calculations;
    - Automatically generated reports
- More effective work process, through:
    - Field-to-field comparisons;
    - Communication in a license setting
    - Easy communication to decision makers
- Effective support to technical decisions:
    - Risk management in a cost perspective;
    - Reduced well construction cost and duration.

By briefly summarizing, the workflow of RiskE can be described as follows [11]:

1. Expression of the uncertainties related to operational and contractual aspects by means of probability distributions
2. Generation of a default operation plan
3. Adjustment of the generated operation plan
4. Definition of the potential undesirable events
5. Execution of the Monte Carlo simulation
6. Investigation of results
7. Adjustment of operational and/or contractual parameters
8. Execution of a “re-analysis”.

4.3. Probability Distributions and Monte Carlo Simulation in RiskE Software

In the previous section it was explained that probability distributions and Monte Carlo simulations are the base of the RiskE software. Therefore understanding the basic knowledge and methodology used is relevant in order to use this software.

In this section different probability distribution and their relation to drilling and P&A operations will be explained. Basic theory of Monte Carlo simulation will also be described. A simple example case of how the RiskE software simulates forecast will also be explained. The simulation will be motivated from the casing cutting and wellhead cost scenario and the it will be based on a simple model that is implemented using the Matlab Software developed by MathWorks.

4.3.1. Probability distribution

According to probability theory, probability distributions, known also as probability density or probability mass, is a function, graph, table or formula that describes which values random variable can take and what is the probability that the random variable can take this value.

In drilling operations, probability distributions are widely used to represent estimation on what to expect and this can be used when planning ahead for the operation. For example the answer to a question on how long does it take to drill a 200 m section of sandstone in X field is not a singular number. Several uncertainties associated with the process e.g. ROP, formation hardness, etc. will result in a probability distribution function. Throughout the operation the functions and results can be updated with the uncertainties solved as more data collected resulting in a confidence in having larger probability for certain values or events.

Different operational parameters or impact of different events can be represented by different types of probability distributions which reflects the true nature of this random variable. These probability distribution are built based on historical data and experience, expertise, dataset, mathematical methods, technical specification or combinations of them. Further in this section different relevant probability distributions will be briefly explained.

- **Single Value**
  Single value is actually not a probability distribution. It has one value and no uncertainty or it is 100% certain it will happen. It could also be called a deterministic value.

  An example case in drilling operation scenario could be representing cost of drilling tool rent per day lump sum i.e. contract of MWD tool is 500.000 NOK per day regardless operational status e.g. drilling, WOW or standby. It has only one value of 500.000 NOK per day regardless what happens.

- **Uniform Distribution**
  Uniform distribution is a probability distribution where all the values between the maximum and minimum value has equal probability of occurring equal to *1/(max-min)*. The value outside the minimum and maximum value has zero probability of occurring. In **Figure 11** a plot is shown visualizing the uniform distribution.

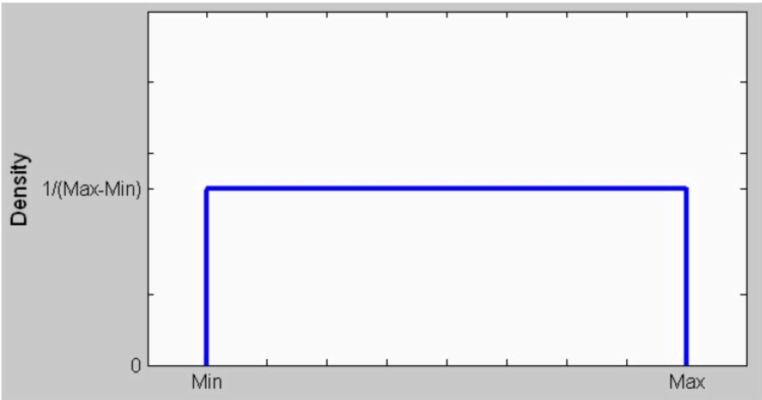


Figure 11. Illustration of uniform distribution [12]

The uniform distribution is usually used if we know a minimum value and maximum value of the parameter but there is no specific knowledge about what the probability are for the values in between.

One example of uniform distribution in drilling operation could be the drilling rig operation cost per day. It could be represented in the uniform distribution if we chose so. Knowing the minimum and maximum value of each individual contract in the drilling rig, e.g. catering, helicopter, crew, power, supply, etc., one can add all this and have a new minimum and maximum value of the rig cost per day. On the other hand one does not have a specific knowledge for the probabilities of the values. Hence using the uniform distribution is suitable in this case.

- **Triangle Distribution**

Triangular distribution is a continuous probability distribution specified by its lower limit, most probable value and maximum value. The probability distribution function is described by f (x|min, max, most probable). Shown here below in **Figure 12** is an illustration of triangle distribution.

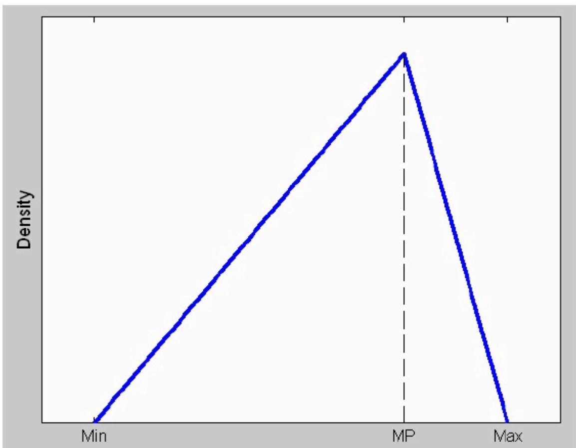


Figure 12. Illustration of triangle distribution [12]

We can see above that the probability increases linearly form zero at the minimum value to highest function value at the most probable value and decreases again linearly to zero at maximum value. Drilling engineers use the triangle distribution quite often due to the simplicity of generating it, on the other hand it represents the variable with more in depth knowledge compared to the uniform distribution. By obtaining knowledge of the max, min, and most likely value of a variable from technical limitation, history, experience, etc. one can generate a representative probability distribution.

An example of triangle distribution in drilling operations could be ROV survey time on a wellhead before commencing P&A operation. The minimum time will be based on knowledge of how long will it takes to reach the seabed and doing the standard procedure, the maximum time is the maximum operation time planned and the most probable is based on previous experience from similar operations.

A common mistake in the triangle distribution generation is the input minimum, maximum and most probable definition by the user [13]. The minimum and maximum value from offset data is not the minimum and maximum value for the triangle distribution. The minimum and maximum value in the triangle distribution has zero probability where the minimum and maximum value in the offset data has occurred therefore they have a probability to occur. Here below in **Figure 13** is an example of a historical data generated triangle distribution, one can see the difference of minimum and maximum value for the offset data and the triangle distribution.

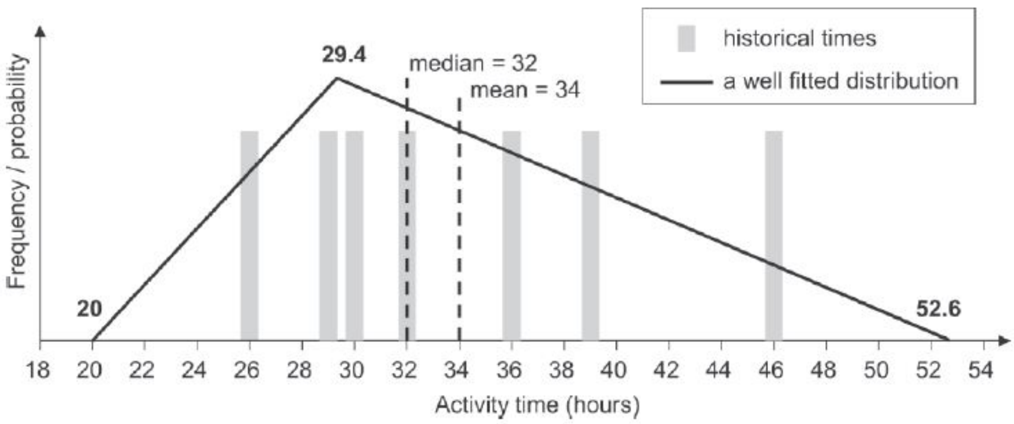


Figure 13. Historical data generated triangle distribution [13]

- **Normal Distribution**

Normal probability distribution, also called Gaussian distribution or bell curve, is a continuous distribution function that is described by its mean and standard deviation or variance. This distribution is suitable for a variable that has one most expected value with a symmetrical variation. Here in **Figure 14** is an illustration showing a typical normal distribution plot.

Although it could be difficult to estimate the standard deviation of a function, one can estimate the standard deviation by the knowledge there is 0.68 probability that the random variable will be within on one standard deviation of the mean and 0.95 probability the random variable will be in between two standard deviation of the mean.

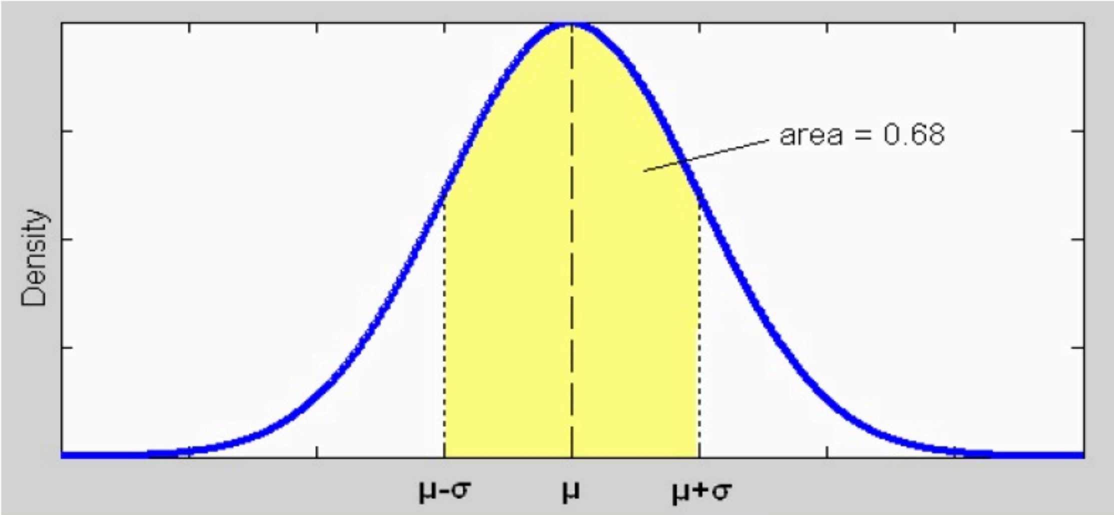


Figure 14. Illustration of normal distribution [12]

Repair time of a tool failure could be one of the examples in drilling operations. It has the most expected value from the standard operating procedure while it could be faster or do not need any repairs at all and it could be an infinite time to repair (tool broken). One could also have sufficient data or track record to determine the standard deviation or variance. But this probability distribution has a disadvantage that it has minus infinity as a minimum value. In drilling operations cost and time input, negative values does not occur then an additional function needs to be introduced to cut the probabilities of negative values.

- **Generic Distribution**

The generic distribution is a probability distribution that is based on a set of known data. This distribution is used for a set of data that does not fit with any mathematical probability distribution function. Here below in **Figure 15** is an illustration showing the generic distribution probability plot.

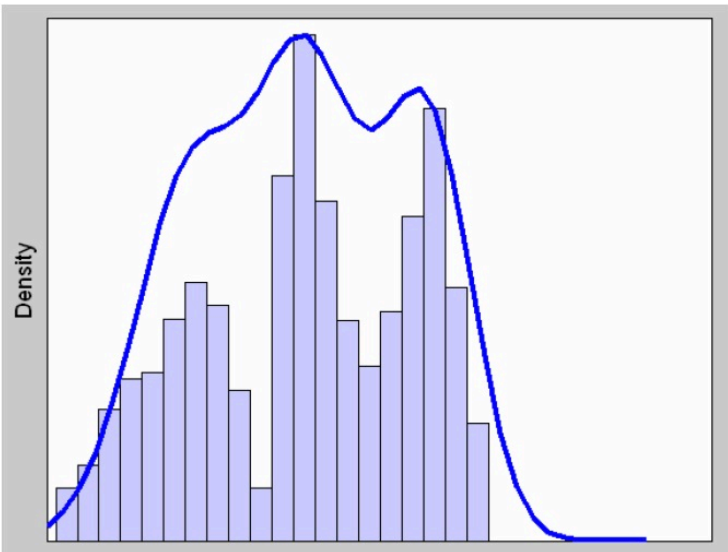


Figure 15. Illustration of generic distribution [12]

In drilling operation the ROP of drilling in a field could be an example of a generic distribution. It will be particular with the field for its formation layers and not follow any mathematical distributions. Historical data of the ROP could be used to generate the distribution.

- **Discrete Distribution**

The discrete distribution is another type of distribution where the values of the variable only can take certain isolated values with its probabilities. It has finite number of values, all probabilities must be between zero and one and the sum of the probabilities must be one. An example of a discrete distribution of bit use is shown below in **Figure 16**

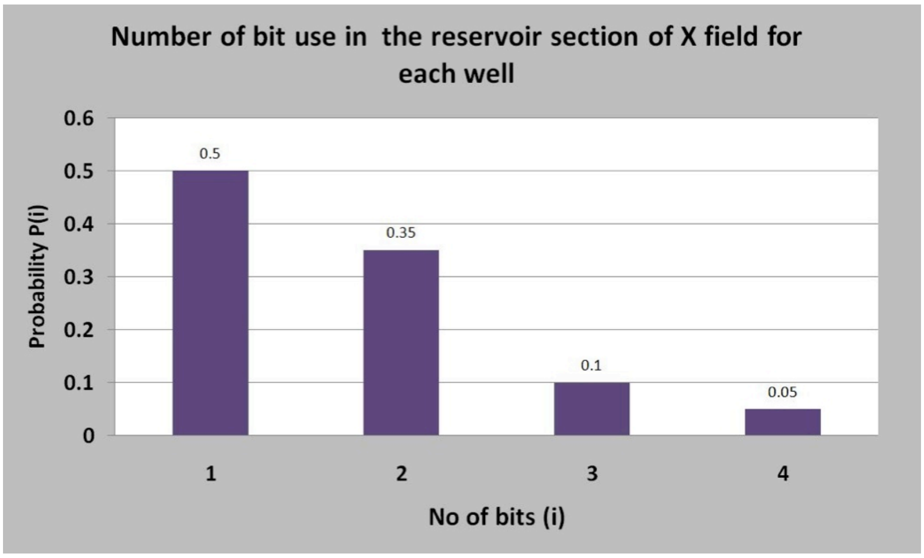


Figure 16. Illustration of discrete distribution

Table 7. Values with corresponding probabilities to construct the discrete distribution of Figure 16

No of bits (i)	Probability P(i)
1	0.5
2	0.35
3	0.1
4	0.05

The discrete distribution of the bit use in the reservoir section could be based on previous experience and constructed from a historical data set. The typical data set to generate a discrete distribution is a table shown above in **Table 7**.

4.3.2. Monte Carlo Simulation

Monte Carlo simulation is a stochastic technique of problem solving used to approximate the probability of certain outcomes by running multiple runs using random variables. The simulation performs certain analysis describing the possible results. This is done by substituting ranges of input values with a probability distribution for parameters that has uncertainties.

In a Monte Carlo simulation, a model is built consisting of different random input variables. The inputs are given as probability distributions. These inputs are then processes with known function of the output parameter. Each result is recorded and this process is called iteration. This process is repeated many times in the order of thousands to produce results which are shown in a probability distribution of the possible outcomes e.g. histogram.

The Monte Carlo method could also be a tool for risk identification and mitigation in the oil and gas industry with analysis of offset data and operating practices. Some examples where Monte Carlo could be used in drilling operation could be: evaluate a plan of avoiding spudding in winter to operate in a lower WOW probability time frame, changing surface location or trajectory to avoid geological drilling hazard and so on [13]. According to Williamson et al. [13], the benefits of Monte Carlo simulation in drilling operations are [13]:

- The forecast or possible outcomes of the drilling operations ahead will include full range of possible uncertainties. By incorporating historical data, knowledge, offset well data, etc. it avoids the systematic optimism of deterministic estimation.
- Provides quantified statement of likely project outcomes enabling a sound, consistent and traceable based decision-making.

Although the process of executing the Monte Carlo itself is simple and quick compared to other oil and gas simulation such as reservoir simulation, the preparation and evaluation of the results are essential. Systematically there are five steps involved when applying the Monte Carlo simulation method as shown below [13]:

1) **Defining the Model**
   Here the forecaster defines what are to be forecasted, and the outputs of the model. The scope of the analysis is also defined.

2) **Data Gathering**
   Assuming that the exact values of the model inputs are unknown, data gathering will be the basis to help quantifying the uncertainties. Because the data is different in time and space from the subject of the forecast the data set could be phrased as offset data. Choosing proper offset data is the key step in a well forecast. A poor and unreliable offset data input will result in useless result.

3) **Defining Input Distribution**
   By having the knowledge of offset data, one could define the probability distribution shape (uniform, triangle, etc.) which one will sample each uncertain input to the model and also the parameter (min, max, standard deviation, P10, P50, P90, etc.).

4) **Sampling Input Distribution**
   Here the computer will generate the input by taking random sample according to the probability distribution function defined. Two or more input quantities result in joint distribution that deviate from statistical independence. The two inputs will have a relationship or common influence called correlation. A correlation should be established and should reflect in the sampling method to represent the physical reality.

5) **Interpreting, Re-evaluating and Using the Results**
   The output of the process will be a set of probability distribution curves or histogram for each forecast quantity. This result needs to be evaluated and corrected if there are any mistakes. The final result could be used for business processes, justification, budget allocation, risk mitigation, setting target and expectations.

4.3.3. Example case

This section will elaborate on a simple example case on how a Monte Carlo simulation with probability distributions is used in a P&A operation with Matlab software. RiskE software also uses the same basic method with this example which will give an understanding an understanding of the inner structure of the program. The steps of the simple simulation will follow the theory in the previous section.

1) **Wellhead retrieval case model**

   The Monte Carlo simulation in this case will forecast the total duration and total cost of phase 3 of the P&A operation that is retrieving the wellhead and cutting the casing 5 m below the seabed. The output will be a probability distribution of the total well cost and duration in form of a histogram, values of P10, P50 and P90 will also be obtained.

2) **Operational and Cost Data Gathering and Input Distribution Determination**

   The engineers then collect history data, offset well data and expertise for this operation. After evaluation and research on the wellhead retrieval operation they conclude that the total cost (TC, Million NOK) and total duration (TT, Million NOK) will be calculated by the following formula:

$$TT = 2 \times \frac{DST}{VSP} + IST + ACT + WRT + FST \quad (1)$$

$$TC = MCC + TT \times \frac{CPD}{24} \quad (2)$$

   Where,

DST	=	Distance to location (km)
VSP	=	Vessel average cruising speed (km/h)
IST	=	Initial survey, net cover retrieval and run in hole time (hr)
ACT	=	Abrasive cutting time (hr)
WRT	=	Wellhead retrieval time (hr)
FST	=	Final survey and pull out of hole time (hr)
MCC	=	Vessel mobilization call-out cost (Million NOK)
CPD	=	Vessel operating cost per day (Million NOK per day)

   Due to the uncertainty of every input the Monte Carlo simulation is needed to solve the final result that represents the probabilities of the possible outcome values. The engineers with the data knowledge then define the input distribution that represents the uncertainties in the inputs. The input distributions below are just example numbers, both with respect to distribution type and value. The main intention is to demonstrate the inputs for Monte Carlo simulation. The input distributions are:

   - Distance to location (DST, km)
     The distance to the location is a single value input due to the certainty of the survey and mapping. It was provided from the vessel company that the distance from the port to the location is 50 km.

- Vessel average cruising speed (VSP, km/h)
  The vessel contractor gave the vessel average cruising speed input by analyzing the weather condition, technical specification and regulations. It was determined that the average cruising speed could be represented by a triangle distribution with 20 km/h as the minimum probable, 30 km/h as the most probable and 35 km/h as the maximum probable value.

- Initial survey, net cover retrieval and run in hole time (IST, hr)
  From previous operation experience of the intervention vessel company, the initial survey, net cover retrieval and RIH time was uniformly distributed with the minimum of 2 hours and maximum of 4 hours.

- Abrasive cutting time (ACT, hr)
  The wellhead retrieval and abrasive cutting company simulates and predicts the duration of possible cutting scenarios and also consider historical offset data for the cutting time. It was informed that the time was normally distributed with the mean time of 3 hours and 1 hours of standard deviation. But it was also informed that the minimum time possible to complete the cutting is no less then 1.5 hours. The normal distribution plot needs to be adjusted by cutting the minimum value.

- Wellhead retrieval time (WRT, hr)
  Similar to the cutting time the wellhead retrieval time was also normally distributed with mean time of 1 hours and 2 hours of standard deviation. The minimum time to complete the operation was 0.5 hours. The normal distribution plot needs to be adjusted by cutting the minimum value.

- Final survey and pull out of hole time (FST, hr)
  Similar to the initial survey, the final survey and pull out of hole time was uniformly distributed with 1 hour of minimum time and 2 hours of maximum time.

- Vessel mobilization call-out cost (MCC, Million NOK)
  The contract with the vessel company for the callout cost is lump sum of 5 million NOK for each callout.

- Vessel operating cost per day (CPD, Million NOK per day)
  Due to the nature of contracts and individual small contracts for the vessel, the total operating cost of the vessel per day for the phase 3 P&A is uniformly distributed with the minimum cost of 1,5 Million NOK per day and maximum cost of 2 million NOK per day.

Here below shown in **Figure 17** are the probability distribution histograms for the input values of the phase 3 wellhead retrieval P&A cost and duration forecast.

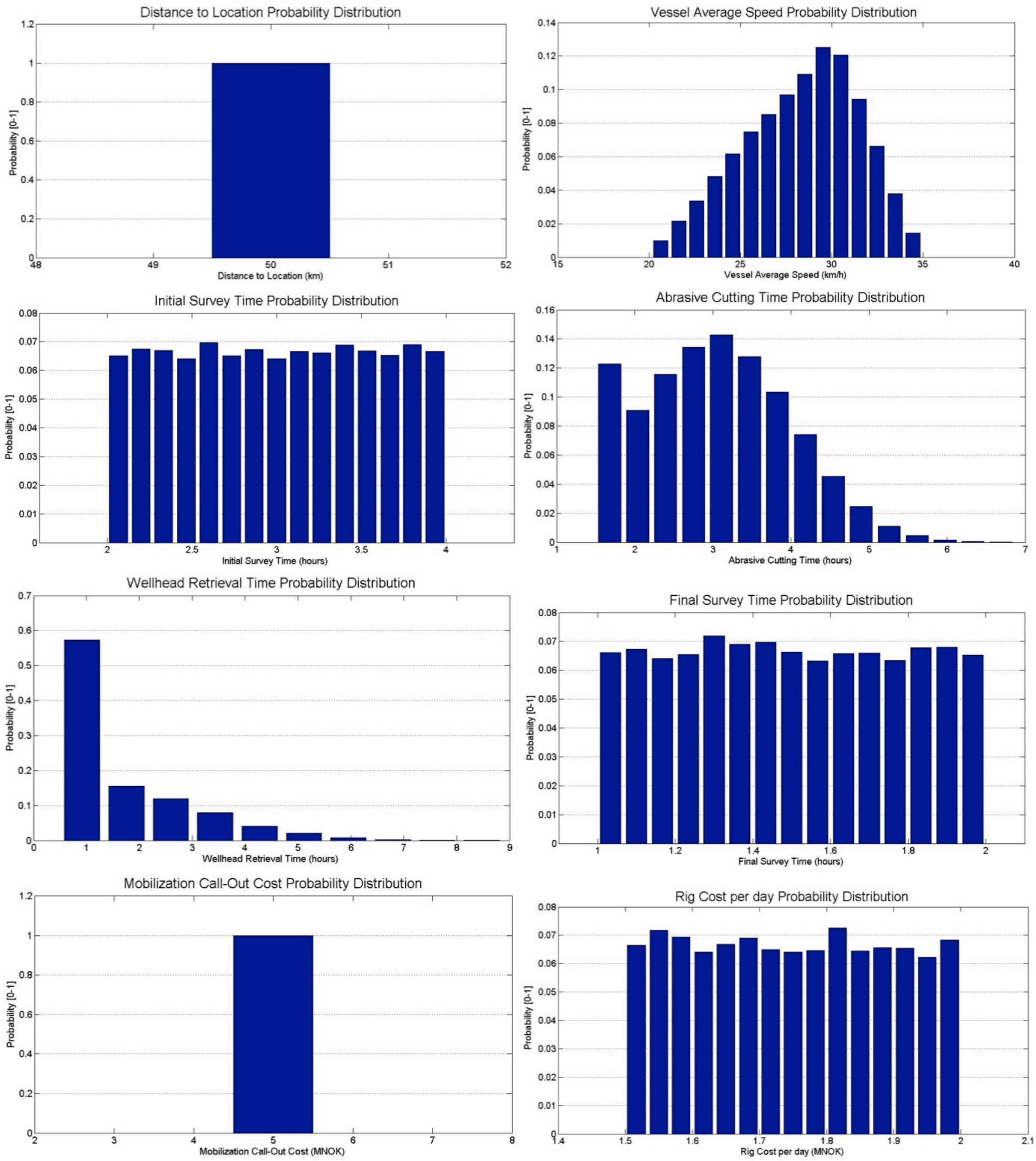


Figure 17. Probability distribution of the input parameters

3) Monte Carlo Simulation

Once the engineer evaluates and approves the data provided by the vendors and research team, the Monte Carlo simulation for forecasting the probability distribution histograms of the total time and cost could be done. In this case Matlab is used as the software-programming tool. Here below is shown the code that was used to perform 10000 iterations and generate the final results.

```
%Wellhead Retrieval Cost and Duration Monte Carlo Simulation
%Filename IndonesiaPNA
%This software is used to simulate a subsea wellhead retrieval using intervention vessel
%The main output is Total Duration (TT) and Total Cost (TC)

function [TT,TC,MCC,CPD,DST,VSP,IST,ACT,WRT,FST]=indonesiapna(N) %N = Number of Itteration
for i=1:N
    %Input Distribution
    MCC=5;                          %Rig chase vessel call-out cost (MNOK),single value
    CPD(i)=unifrnd(1.5,2);          %Rig chase cost perday (MNOK), uniform distribution with min 1,5 and Max 2
    DST=50;                         %Distance to location (km), single value
    VSP(i)=trianglerand(20,30,35,1); %Vessel Speed (km/h), triangle distribution with min 25, Most Prob 30, max 40
    IST(i)=unifrnd(2,4);            %Initial survey time (hr), uniform distribution min 2 and max 4
    ACT(i)=max(1.5,normrnd(3,1));   %Abrasive cutting time (hr), normal distribution with min 1,5, mean 3, stdev 1)
    WRT(i)=max(0.5,normrnd(1,2));   %Wellhead retrieval time (hr), normal distribution with min 0,5, mean 1, stdev 2)
    FST(i)=unifrnd(1,2);            %Final survey time (hr), uniform distribution min 1 and max 2

    %Final Result Calculation
    TT(i)=2*DST/VSP(i)+IST(i)+ACT(i)+WRT(i)+FST(i);     %Total time needed for the operation (hr)
    TC(i)=MCC+TT(i)*CPD(i)/24;                          %Total cost needed for the operation (MONOK)
end
```

4) **Wellhead Retrieval Cost and Duration Results and Simple Analysis**

After running the simple software the forecast result are obtained. Here shown in **Figure 18** and **19** are the probability distribution forecast of the total duration and total cost of phase 3. Probability distribution plot is one of the tool for helping in the decision making and risk mitigation.

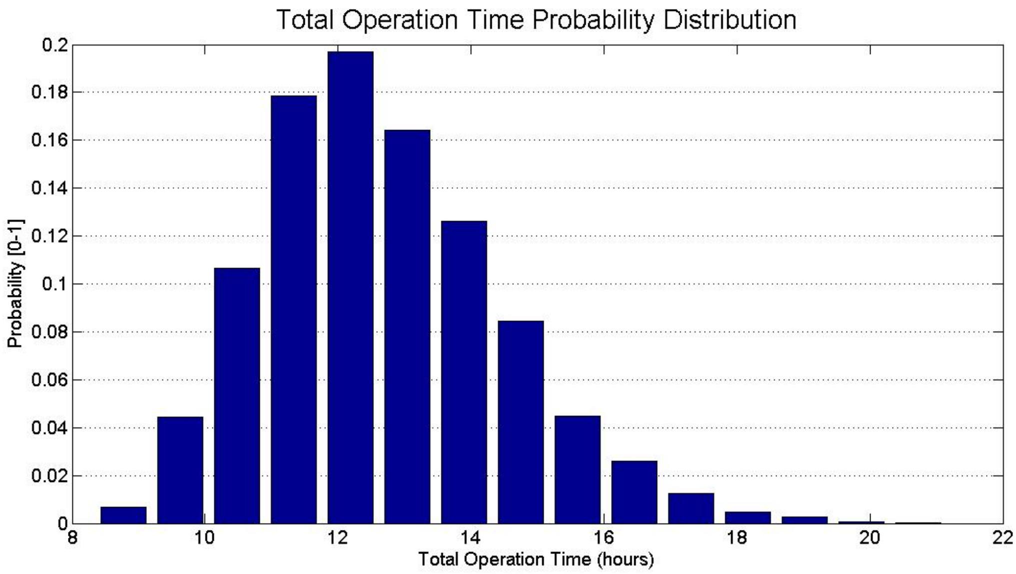


Figure 18. Total operation time probability distribution

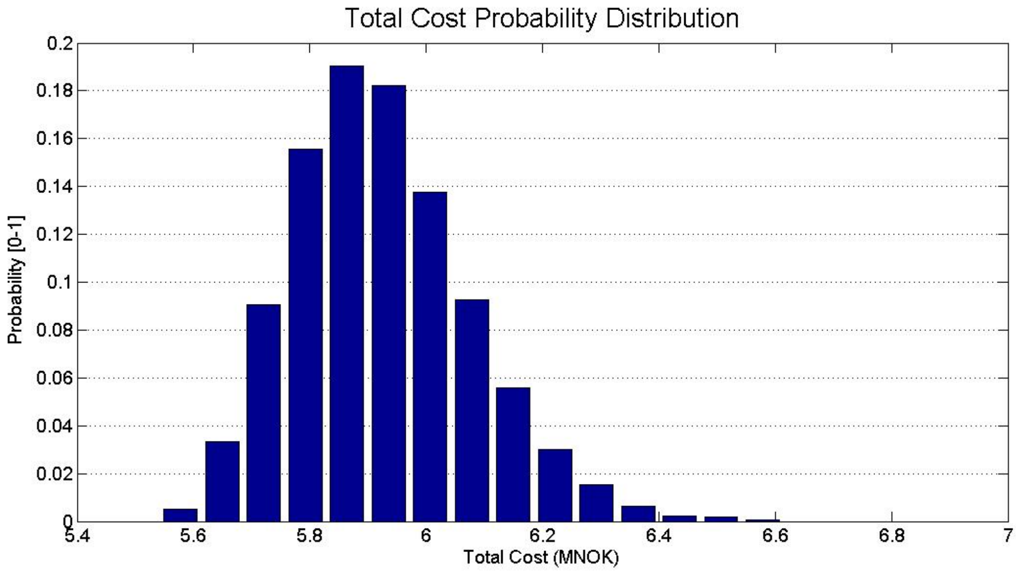


Figure 19. Total cost probability distribution

Statistical properties of the forecasts can also be derived from the probability distribution plots. These statistical properties are also tools for the decision makers to improve the efficiency of the operation. Here shown in **Table 8** are the statistical properties of the forecasts.

Table 8. Statistical properties of the forecast result

Statistical Parameter	Forecast Result	
	Total Time (hours)	Total Cost (MNOK)
P10	**10.52**	**5.74**
P50	**12.47**	**5.99**
P90	**15.05**	**6.13**
Mean	**12.67**	**5.92**
Median	**12.47**	**5.91**
Standard Deviation	**1.8**	**0.15**

A simple analysis from the percentile and standard deviation is that the range of the total cost is most likely not very large. The difference between P10 and P90 is only 0.39 MNOK, this is small compared to the total cost. One can conclude that this operation is not risky since there is no large variation or spread in the result. Updating the input to single values once an event has occured could also reduce the uncertainties of the final result.

The engineer of this project can also see that although there is an uncertainty in the total cost, a large portion of the total cost is contributed by the mobilization call-out cost which is 5 MNOK with single value distribution. By conducting the operation in batch or multiple well P&A, the cost per well could be reduced. This is due to the sharing of the mobilization cost.

This represents a simple example case for performing a Monte Carlo simulation for predicting the probability of duration and cost estimates for a P&A operation. Although adding risks of undesired events in an operation could be included on a forecast in RiskE, similar basic principles are used to solve numerous problems of forecasting.

4.4. RiskE Software Model Structure and User Interface

The RiskE software has a user friendly and organized interface. It was originally developed for modeling the drilling phase. The software is organized in a way that it guides the user through the inputs and executing in the following steps [11]:

1. Development of the operation plan
2. Analysis of costs and durations associated with the planned operations
3. Connection of possible undesirable events to the standard Operation Plan, in order to obtain the Risk Operation Plan
4. Modeling of sensitivity related to both cost/duration contribution and uncertainties
5. Identification of suitable preventive measures (alternatives to the base case)
6. Identification of the most appropriate alternative

Figure 20 below shows how the software tool model is structured. After building the well architecture, construction and description, there are phases that are inserted by the user to elaborate the operation plans. In RiskE the phases are drilling, mobilize, spudding, BOP and abandon. For each phases one could insert operations in the operation plans and undesired events in the risk operation plan section. The value of the inputs and probability distributions could be also inserted.

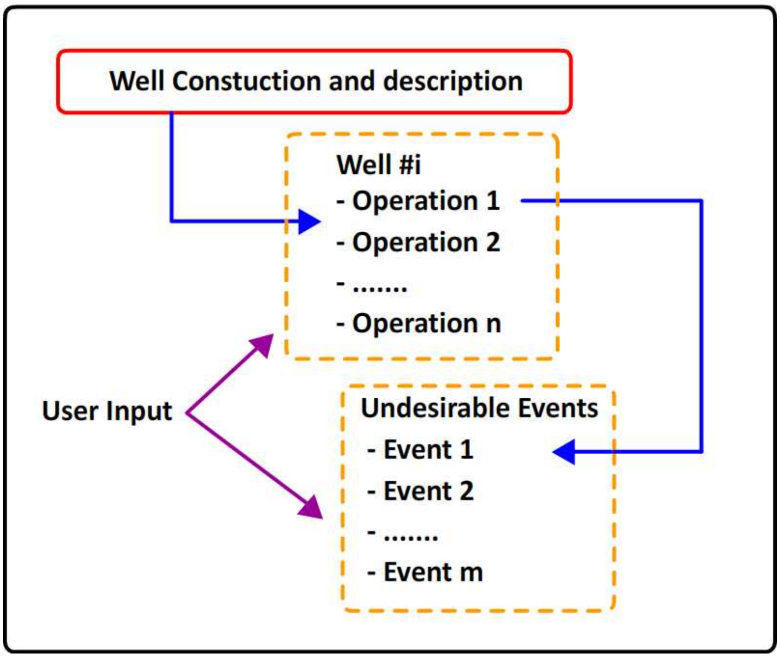


Figure 20. Tool model structure

4.5. RiskE Software Output

The final result of the RiskE software after assessing input parameters and operation plan are a set of results data ready for further analysis and a tool for decision-making. According to Merlo et al. [11], the outputs can be presented in several ways as listed below [11]:

- **Mean duration and cost vs drill depth.** The curve of mean duration and cost vs depth are derived from the input distribution vs time.
- **Drill depth vs time curves.** The percentile plots of drilling depth forecast vs time.
- **Well construction duration.** Histogram, min and max values, mean, standard deviation, percentiles and CDF curves are given from the probability distribution of the total well construction duration.
- **Well construction cost.** Histogram, min and max values, mean, standard deviation, percentiles and CDF curves are given from the probability distribution of the total well construction cost.
- **Cost and duration limits.** Obtaining the probability of performing the construction of the well within a user defined cost and duration threshold.
- **Sensitivity analysis based on cost and duration contribution.** This output will allow user to rank the events, phases and operation based on the mean portion of the total well construction cost and duration.
- **Cost breakdown.** The mean cost categorized according to ENI E&P cost coding standards.
- **Comparison of well construction plans.** Comparing several well construction scenarios alternatives on the total well construction cost and duration histogram and also drilling depth vs time and cost vs time curves.

Here below on **Figure 21** and **22** are the screenshots of the interface in RiskE on showing the result to the operation plan forecast and also a comparison between two alternatives.

Figure 21. Risk operation plan forecast result interface in RiskE software

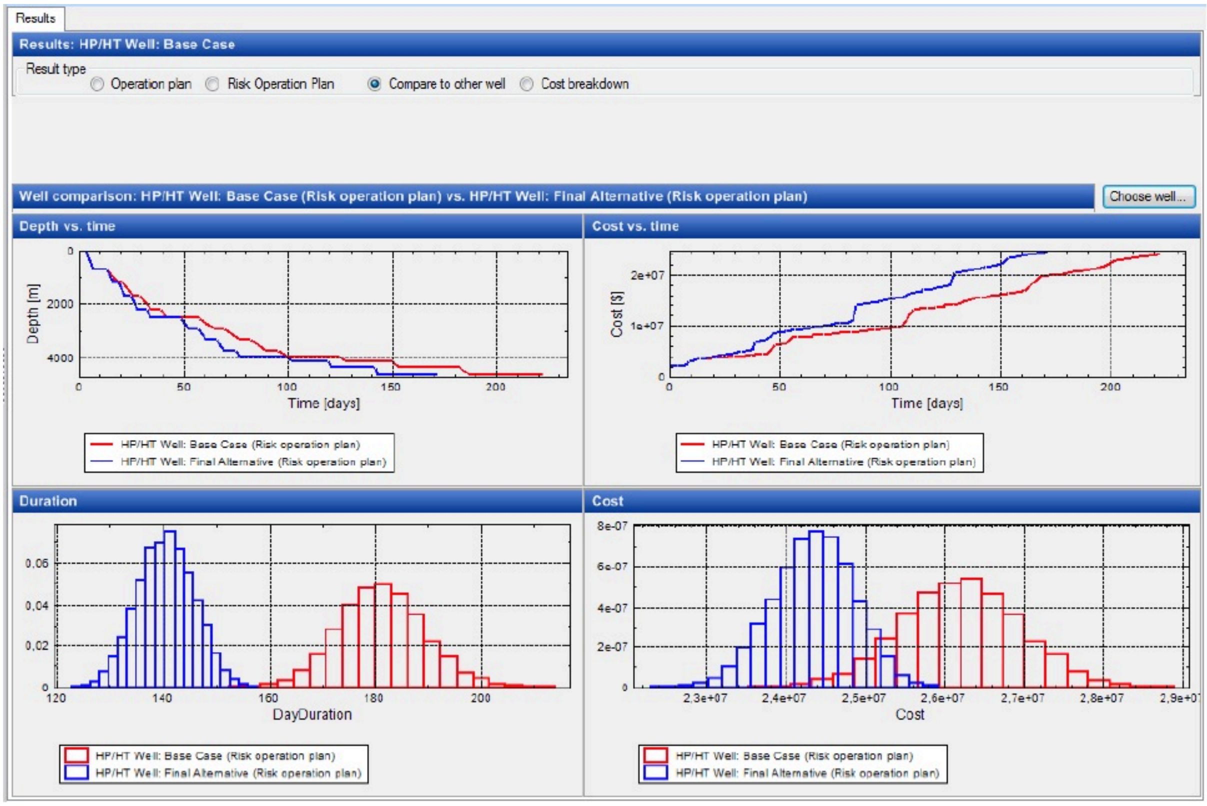


Figure 22. Comparison of duration and cost of the alternatives interface in RiskE software

5. Comparison of Subsea Exploration Well Scenarios of Permanent P&A Operation

In this section cost and duration forecast will be performed for a subsea exploration well P&A operation using the RiskE software. Several cases will be reflecting actual possibilities of operation in the field. The cases are divided into two comparison assessments as listed below:

a. **Method Comparison.** Four cases will be compared where in each case different technologies or vessels will be used to perform the P&A operation of a subsea exploration well. The difference are mainly the use of semi submersible rig, intervention vessel, rig chase vessel or combination of them to perform the phase 1, phase 2 and phase 3 P&A. The cost and duration forecast results then will be compared and analyzed.

b. **Batch Comparison.** Two cases will be compared where different vessels will be used to perform the P&A phase on a series of subsea exploration wells. The cost and duration forecast result will then be compared and analyzed, focusing mainly on the different factors that affects the total P&A cost and P&A cost per well.

5.1. Background

The ultimate goal of the simulation is to prove that the Monte Carlo simulation could be used to forecast P&A scenarios. The forecast results of different methods and batch operation to the cost and duration forecast will also be studied, but the exact values of these results will not be 100% accurate. Although the operational procedure and values are given by the experts, the values used are to some extent example values and the operations considered may not cover all the necessary operations needed. More studies and expertise are needed to generate comprehensive input for more accurate forecast.

5.2. Simulation Model Well Construction and Architecture

In order to simulate the scenarios, five example subsea wells are made. The example wells are located in the Bandung-32 artificial field, the field map shown in **Figure 23.** The wells are scattered with distances specified in the map. The subsea exploration wells are to be drilled with a semi submersible drilling rig one after another with identical well construction operation and architecture. The wells are vertical cased hole perforated with a well construction and architecture shown in **Figure 24.** The subsea exploration wells will be permanently abandoned after the drilling and data gathering process.

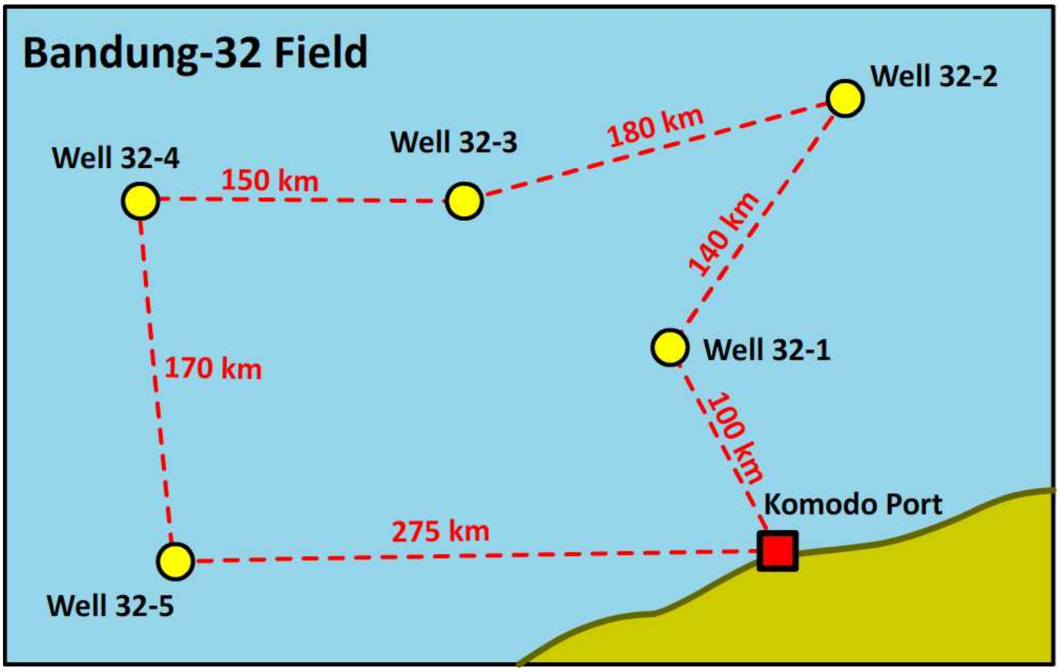


Figure 23. Bandung-32 field map

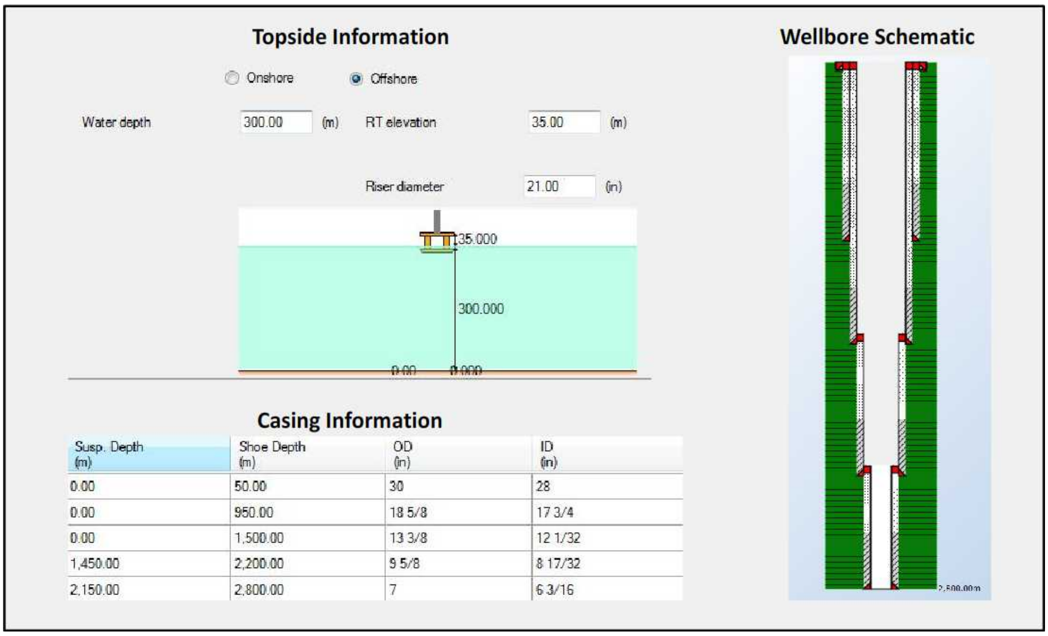


Figure 24. Bandung-32 exploration wells information

5.3. Case Definition Setup

As mentioned in the beginning of the chapter, several P&A scenario cases will be forecasted with respect to cost and duration. The cases will be compared both with respect to the use of different technologies/vessels and also batch operation. The initial condition before the P&A operation is that the semi submersible drilling rig is still in position and the well has a perforated cased hole perforation completion without any tubular in the well. According to NORSOK guideline also mentioned in section 2.3.4., a P&A operation is considered complete when the final condition is:

- **Phase 1 P&A reservoir abandonment is complete.** Assuming the reservoir has potential pressure from hydrocarbon then two well barriers need to be established. The primary barrier consists of the cement plug bullheaded to the reservoir and the cement behind the liner or casing. The secondary barrier is another cement plug located above the primary barrier set above a mechanical or hydraulic packer and cement behind the liner or casing. Assuming that the cement behind the casings and liners are already surveyed and the integrity has been confirmed in the drilling process no extra well logging needs to be performed.

- **Phase 2 P&A intermediate abandonment is complete.** Phase 2 of the P&A is the wellbore to surface barrier usually set 200 m below sea bed. The wellbore is plugged with a cement plug set above a mechanical/hydraulic plug. Besides the main borehole, the annulus/annuli also need to be cement plugged. This operation could be performed by new technologies such as WASP/SWAT.

- **Phase 3 Wellhead and casing retrieval.** In this phase the goal is to retrieve any traces of oil and gas activity on the seabed and also 5m below the seabed. The casings are cut and retrieved together with the wellhead. The method to complete this phase could be with an abrasive casing cutter or with cutter knives.

To Plug and Abandon all five wells in Bandung-32 Field different possible cases are planned. These cases are then forecasted and analyzed from a cost and duration point of view with the RiskE software. First the cost and duration of four cases are compared for plugging and abandoning one single well. The second comparison is comparing two cases of plug and abandonment operation for the whole field that consists of five identical wells.

Further in the subchapters more detailed explanation about the case comparisons will be elaborated.

5.3.1. Method Comparison Cases

The first comparison is the method comparison, four single well P&A cases will be forecasted and the results will be compared from a cost and duration point of view. The method main differences are the use of different type of device (e.g. Semisub, Intervention vessel, Rig chase vessel) to execute the different phases of the P&A. This variation will result in different spread rate, daily cost, operation events, duration, extra costs, etc.

In **Table 9** below the four cases for method comparison are shown. From the table it can be seen that the advantage of the first case is that there is no mobilization cost for other vessel and no time wasted for a temporary suspension. But the first case has a disadvantage related to the fact that the semi submersible rig has a very large daily rate. In contrast using vessels for abandoning will result in lower daily cost and also more time for the rig to perform exploration and production drilling instead of P&A operation. The downside of using vessels is the initial call out and extra mobilization cost.

One should remark that these cases are only for an exploration well case. A P&A campaign of an old oil field would include a mobilization and transit of the semi submersible rig.

A typical intervention vessel nowadays can handle wireline services, pumping services and cementing services in a subsea environment **(Figure 25).** Full specification of a typical intervention vessel could be seen in **Appendix B**.

The operations for the forecast starts from the green line or the end of the drilling and testing phase and ends with the phase 3 final demobilization **Table 9**. More details of the actual events for every case and also probability distribution of time and cost inputs will be presented in section 5.4.

Figure 25. Island Constructor of Island Offshore - typical intervention vessel

Table 9. Method comparison cases

Activity	Scenario			
	Case 1	Case 2	Case 3	Case 4
Setup	Semi Sub	Semi Sub	Semi Sub	Semi Sub
Top Hole and Install Wellhead	Semi Sub	Semi Sub	Semi Sub	Semi Sub
Install, BOP, drilling and testing	Semi Sub	Semi Sub	Semi Sub	Semi Sub
Suspension : Temporary abandonment, net cover	N/A	N/A	N/A	Semi Sub
P&A Phase 1 : Reservoir Abandonment	Semi Sub	Semi Sub	Semi Sub	Intervention Vessel
Suspension : Temporary abandonment, net cover	N/A	N/A	Semi Sub	N/A
Vessel Survey and setup	N/A	N/A	Intervention Vessel	N/A
P&A Phase 2 : Intermediete Abandonment	Semi Sub	Semi Sub	Intervention Vessel	Intervention Vessel
Suspension : Temporary abandonment, net cover	N/A	Semi Sub	N/A	N/A
Vessel Survey and Setup	N/A	Rig Chase Vessel	N/A	N/A
P&A Phase 3 : Wellhead Removal	Semi Sub	Rig Chase Vessel	Intervention Vessel	Intervention Vessel
Final Demob	Semi Sub	Rig Chase Vessel	Intervention Vessel	Intervention Vessel

5.3.2. Batch Comparison Cases

The batch comparison case will compare case 1 and case 2 from section 5.3.1. The difference is that the P&A operation will be executed for five consecutive wells in the Bandung-32 field. The case 1 will have a disadvantage of higher spread cost for the phase 3 abandonment but will have advantages such as no extra callout and mobilization cost for the vessel and also well suspension time. The case 2 will have advantages in lower cost per day in the phase 3 operation by using rig chase vessel **(Figure 26)**. Full specification of a typical rig chase vessel could be seen in **Appendix B**.

Figure 26. Island Valiant of Island Offshore- typical rig chase vessel

Although the five wells are identical, the Monte Carlo method used by the RiskE software will result in different cost and duration forecast compared to the sum of five single well cost and duration. This is due to each operation and input has different probability distribution possibilities.

The forecast will compare only phase 3 of the operation due to the identical operation in phase 1 and 2 using the semi submersible drilling rig. The difference for case 2 batch is the temporary suspension by the rig and vessel mobilization, survey and setup. Those events are additional events necessary to be performed for the case 2 operation. Case two is selected due to the relatively similar operation in the 3rd phase to other subsea well P&A operation and not necessary exploration wells. As mentioned on the previous sector, one should remark that these cases are only for an exploration well case. A P&A campaign of an old oil field would include a mobilization and transit of the semi submersible rig.

5.4. Model Input

In this section inputs and operations of the model for the RiskE software will be shown and explained. Although the operational procedure and values are given by the experts, the values used are to some extent example values and the operations considered my not cover all the necessary operations needed. Further studies for the input and operational procedure are recommended to be performed prior to a real forecasting. A case-by-case approach is necessary to be done in an actual P&A forecasting

Although it is possible to add additional risks such as delay due to waiting on weather, equipment failure, operation problems, etc. in RiskE, it will not be included in this study. These needs further studies for the definition and mathematical input.

5.4.1. Rig and Vessel Daily Cost

Shown in **Table 10** are the daily rates of the rig or vessel that is used in each of the cases. The distribution type is uniform. These data are ballpark values given by oil and service companies in the Norwegian Continental Shelf sector.

Table 10. Rig and vessel daily rate

Vessel and Rig Daily Rate			
Type	Rig/Vessel Rate per day (NOK)		Distribution type
	Minimum	Maximum	
Semi Submersible Rig	4000000	5000000	Uniform
Intervention Vessel	2000000	3000000	Uniform
Rig Chase Vessel	1000000	2000000	Uniform

5.4.2. Cases Activity and Operation Time

This section will describe the input for the RiskE simulation for both of the case comparisons. The sequence of activity and operation hours is used as an input as presented in **Table 11, 12, 13 and 14** with their respective probability distribution for each specific case defined in **Table 9**. Each phase and general activity are color coded according to the method used either it is Semi Submersible Rig (Red), Intervention Vessel (blue) or Rig Chase Vessel (green).

As mentioned in the previous section, these data are ballpark values given by oil and service companies in the Norwegian Continental Shelf. Inputs representing the possibility of delay due to waiting on weather, equipment failure, operation problems, etc. are not included in this study although it is possible in RiskE. Further study of the inputs and case by case analysis are necessary for forecasting an actual case.

Table 11. Case 1 operation time

Case 1							
General Activity	Sequence	Activity	Operation Hours min	Operation Hours most	Operation Hours max	Distribution type	Comment
P&A Phase 1 : Reservoir	1	Reservoir Cement plug Primary and Secondary	32		60	Uniform	Hugely depends on waiting on cement time and pressure test
P&A Phase 2 : Intermediete Abandonment	2	Punch, circulate and cement two annulus and hole	80		100	Uniform	Hugely depends on waiting on cement time, pressure test and behind the casing circulation
	3	Nipple down BOP	16		22	Uniform	
P&A Phase 3 : wellhead removal	4	Casing cutting	4	8	16	Triangle	
	5	Wellhead retrieval	1	2	2	Triangle	
	6	ROV survey after operation	2	3	4	Triangle	
	7	Deanchor and move out	30		50	Uniform	

Table 12. Case 2 operation time

Case 2							
General Activity	Sequence	Activity	Operation Hours min	Operation Hours most	Operation Hours max	Distribution type	Comment
P&A Phase 1 : Reservoir	1	Reservoir Cement plug Primary and Secondary	32		60	Uniform	Hugely depends on waiting on cement time and pressure test
P&A Phase 2 : Intermediete Abandonment	2	Punch, circulate and cement two annulus and hole	80		100	Uniform	Hugely depends on waiting on cement time, pressure test and behind the casing circulation condition
	3	Nipple down BOP	16		22	Uniform	
	4	Install corrosion cap and net cover	2		3	Uniform	
	5	ROV survey after operation	2		3	Uniform	
	6	Deanchor and move out	30		50	Uniform	
P&A Phase 3 : wellhead removal	6	Preparation and Mobilisation of vessel at port	36	48	60	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost
	7	Transit to location					Time depends on distance and spee
	8	Position vessel and survey	1	2	6	Triangle	
	9	Removal of corrosion cap and/or net guard	2	3	4	Triangle	
	10	Casing cutting	4	8	16	Triangle	
	11	Wellhead retrieval	1	2	2	Triangle	
	12	ROV survey after operation	2	3	4	Triangle	
	13	Transit to port					Time depends on distance and spee
	14	Demobilisation	12	18	24	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost

Table 13. Case 3 operation time

Case 3							
General Activity	Sequence	Activity	Operation Hours			Distribution type	Comment
			min	most	max		
P&A Phase 1 : Reservoir	1	Reservoir Cement plug Primary and Secondary	32		60	Uniform	Hugely depends on waiting on cement time and pressure test
	2	Nipple down BOP	16		22	Uniform	
	3	Install corrosion cap and net cover	2		3	Uniform	
	4	Deanchor and move out	30		50	Uniform	
P&A Phase 2 : Intermediete Abandonment	5	Preparation and Mobilisation of vessel at port	36	48	60	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost
	6	Transit to location					Time depends on distance and speed input
	7	Position vessel and survey	1	2	6	Triangle	
	8	Removal of corrosion cap and/or net guard	2	3	4	Triangle	
	9	Punch, circulate and cement two annulus and hole	80		150	Uniform	Hugely depends on waiting on cement time, pressure test and behind the casing circulation
P&A Phase 3 : wellhead removal	10	Casing cutting	4	8	16	Triangle	
	11	Wellhead retrieval	1	2	2	Triangle	
	12	ROV survey after operation	2	3	4	Triangle	
	13	Cut Casing with abrasive cutter	2	8	16	Triangle	
	14	Retrieve Wellhead	1		2	Uniform	
	15	ROV survey after operation	2	3	4	Triangle	
	16	Transit to port					Time depends on distance and speed input
	17	Demobilization	12	18	24	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost

Table 14. Case 4 operation time

Case 4							
General Activity	Sequence	Activity	Operation Hours min	most	max	Distribution type	Comment
Suspension by Semisub	1	Bridge plug setting and suspension	12		20	Uniform	
	2	Nipple down BOP	16		22	Uniform	
	3	Install corrosion cap and net cover	2		3	Uniform	
	4	Deanchor and move out	30		50	Uniform	
P&A Phase 1 : Intermediete Abandonment	5	Preparation and Mobilisation of vessel at port	36	48	60	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost
	6	Transit to location					Time depends on distance and speed input
	7	Position vessel and survey	1	2	6	Triangle	
	8	Removal of corrosion cap and/or net guard	2	3	4	Triangle	
	9	Reservoir Cement plug Primary and Secondary	32		60	Uniform	Hugely depends on waiting on cement time and pressure test
P&A Phase 2 : Intermediete Abandonment	10	Punch, circulate and cement two annulus and hole	80		150	Uniform	Hugely depends on waiting on cement time, pressure test and behind the casing circulation
P&A Phase 3 : wellhead removal	11	Casing cutting	4	8	16	Triangle	
	12	Wellhead retrieval	1	2	2	Triangle	
	13	ROV survey after operation	2	3	4	Triangle	
	14	Transit to port					Time depends on distance and speed input
	15	Demobilization	12	18	24	Triangle	This time added to cost but not duration of P&A operation and will be counted as mobilization cost

5.4.3. Batch Case Input Assumptions

For the batch case comparison, the data from case 1 and 2 will be used. Here below are the assumptions for the batch comparison:

- Until the nipple down BOP operation, both case 1 and 2 are identical with one another, the simulation will start with activities after that.
- Operation 4, 5 and 6 in **Table 12** are included in the cost and duration estimation as necessary events for preparing Phase 3 operation of batch 2 case.
- Five wells in the Bandung-32 Field will be forecasted.
- The vessel will travel to each of the wells with their respective relative distances shown in **Figure 24** including one time transit from and to the port**,** hence transit/transportation time will be added in the batch case for the rig chase vessel.
- The rig is already in place after drilling, hence there is no transit/transportation time added in the batch comparison case for the semi submersible rig.
- The vessel will do the phase 3 P&A for each well simultaneously with out a need for going back to port, hence only one call out/mobilization cost will be applied.
- The forecast will be a Monte Carlo simulation of 5 consecutive 3rd Phase P&A operation and not a multiplication of 5 Phase 3 P&A operation of a single well.

5.5. Results

In this chapter results from the forecasting will be presented in tables and graphs for an easier visual comparison. Case 2 histogram and other outputs will be presented, other are shown in **Appendix C.**

5.5.1. Method Comparison

- **Cost Forecast Histogram**

  The cost forecast histogram is one of the output from RiskE software. From this histogram users can see the probability spread of the forecasted cost. Here below shown in **Figure 27 is** the cost forecast for case 2. The purple, green and red line represents the P10, P50 and P90 of the distribution. The P50 cost for completing the whole P&A phase is around 44 MNOK which is the highest among all the methods if done in a single well.

  From the cost histogram engineers could calculate the standard deviation and other statistical variable to study the extreme consideration values and the possible range value to consider in budgetary means. In preparing a proposal for operation budget allocation, the engineers will propose a certain cost allocation to the procurement department to finish the operation. Each oil company has different budget policy and the cost histogram is one of the input on preparing the operation budget allocation.

  The results for other cases could be seen in **Appendix C**. Later in this section comparison table and charts will be presented.

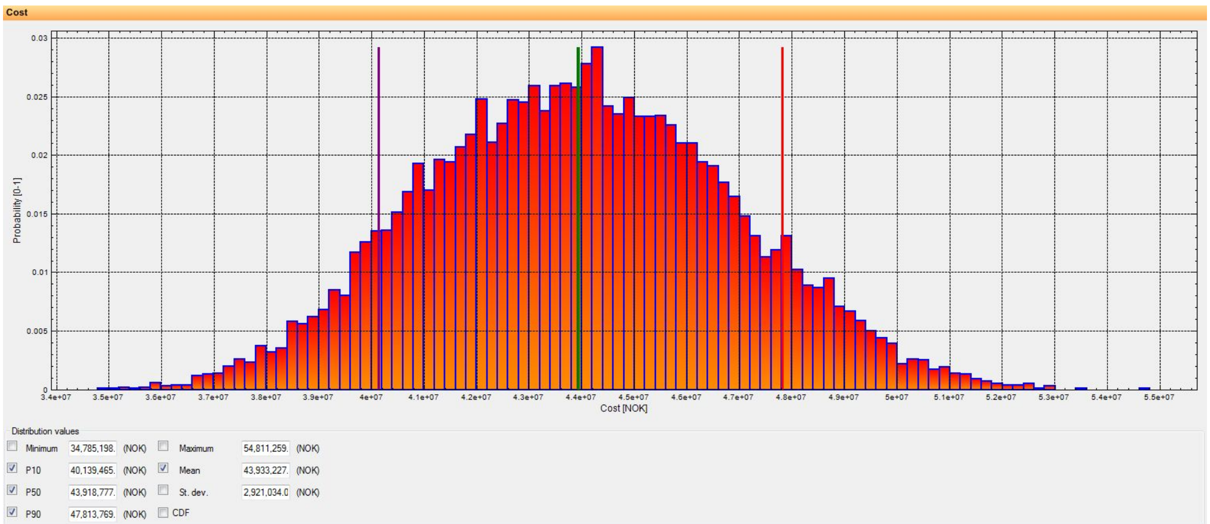


Figure 27. Case 2 Cost forecast histogram

- **Duration Forecast Histogram**

  Duration forecast histogram is another histogram output from the RiskE software. Here in **Figure 28** the duration forecast for case 2 is presented. The P50 of duration for the case 2 P&A operation is 9.4 days.

  This histogram is usually used to estimate the technical operational time allocation for the oil company operation. Technical operation time is the time targeted by the oil company for the field workers to complete if there is no delay in the operation.

The results for other cases could be seen in **Appendix C**. Later in this section comparison table and charts will be presented.

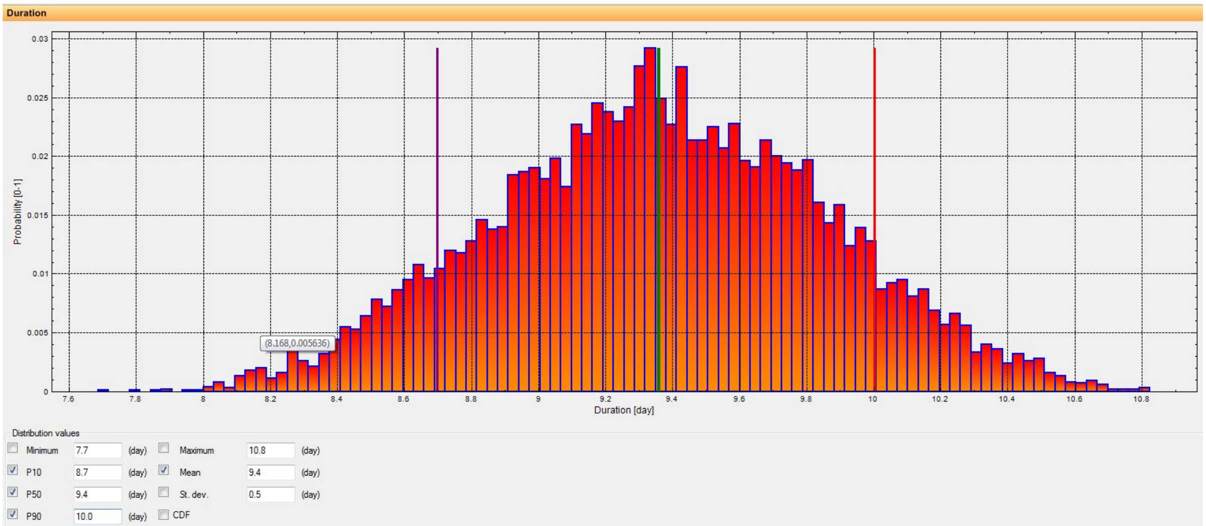


Figure 28. Case 2 Duration forecast histogram

- **Cost and Duration Cases Comparison**
  The statistical values of each cases are compiled in **Table 15** and furthermore bar charts are generated shown in **Figure 29 and 30**. These outputs are tools for the engineers to determine which method is the best for the P&A operation. Technical limit time and budget are usually generated from these statistical values to estimate the resource and budget planning and other assessments. Further discussion regarding the results will be presented in the discussion section.

Table 15. Method Cases statistical values

Case Scenario	Method	Statistical Values							
		Cost (MNOK)				Duration (Days)			
		P10	P50	P90	Mean	P10	P50	P90	Mean
Case 1	Rig -Rig - Rig	35.648	39.134	42.788	39.172	8.1	8.7	9.4	8.7
Case 2	Rig - Rig - Rig Chase Vessel	40.139	43.918	47.918	43.933	8.7	9.4	10	9.4
Case 3	Rig - LWIV - LWIV	35.354	39.629	44.307	39.75	9	10.3	11.6	10.3
Case 4	LWIV - LWIV - LWIV	34.921	38.727	43.017	38.878	9.7	10.9	12.2	11

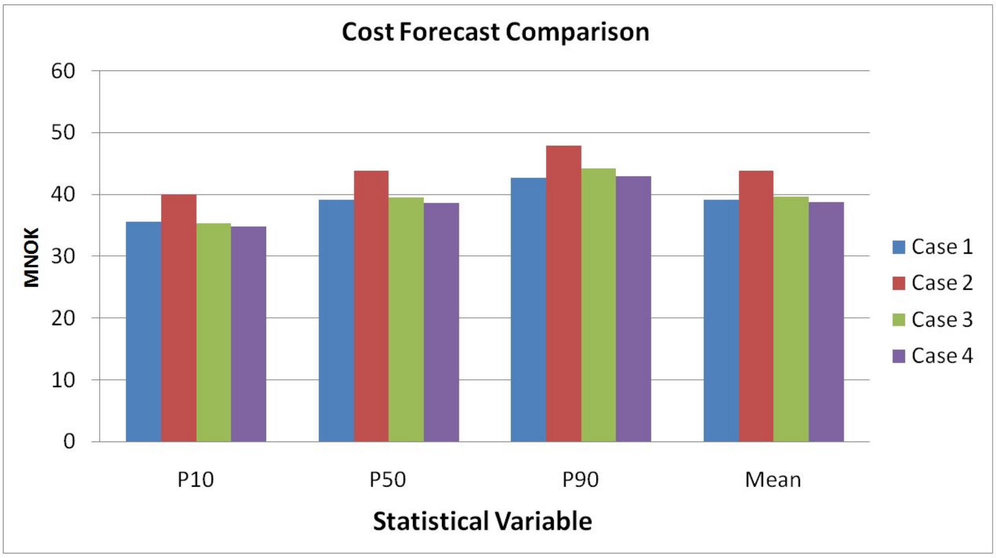


Figure 29. Method cases cost forecast comparison

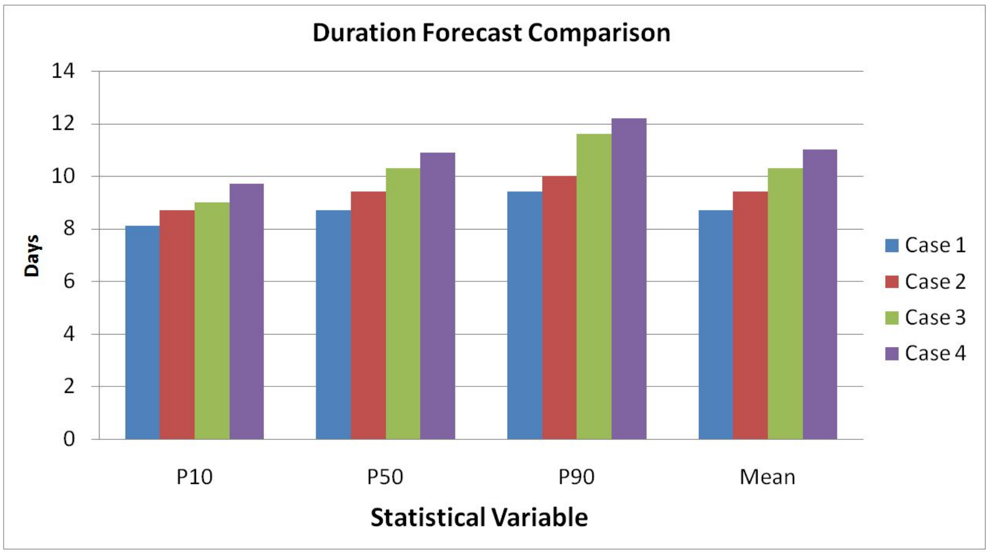


Figure 30. Method cases duration forecast comparison

- **Phase Sensitivity Percentage**
  Phase sensitivity is one of the outputs from RiskE that can be useful in developing more cost and duration efficient operations. By analyzing the percentages given by the output, engineers could see the contribution of each phase on the final outcome and furthermore improve the cost and duration efficiency of that specific phase. Another option is also to see each activity contribution to the final outcome.

  In **Figure 31** a screen shot of this output in RiskE is shown. From the four cases forecast it was observed that the phase 2 takes most time and cost expenditure for the P&A operation to complete. This is the reason why that the case two was the most costly and time consuming case due to the more expensive semi submersible drilling rig use for the phase 2 operation and additional operation and rig chase mobilization that were assumed when both rig and vessel are to be used fot the P&A operation.

Figure 31. Case 2 Phase sensitivity percentage

- **Cost vs Time Plot**

  Shown in **Figure 32** is the cost vs time plot of the operation. The cost associated with the operation for the cases are only day rate and mobilization cost, therefore the graph is a straight line and a jump of cost in the mobilization day representing the callout cost. For more detailed cases with several specific inputs such as cement cost, logging cost, cutting cost etc. more features in the graph will appear. This helps engineers to associate corresponding cost with its duration and time frame.

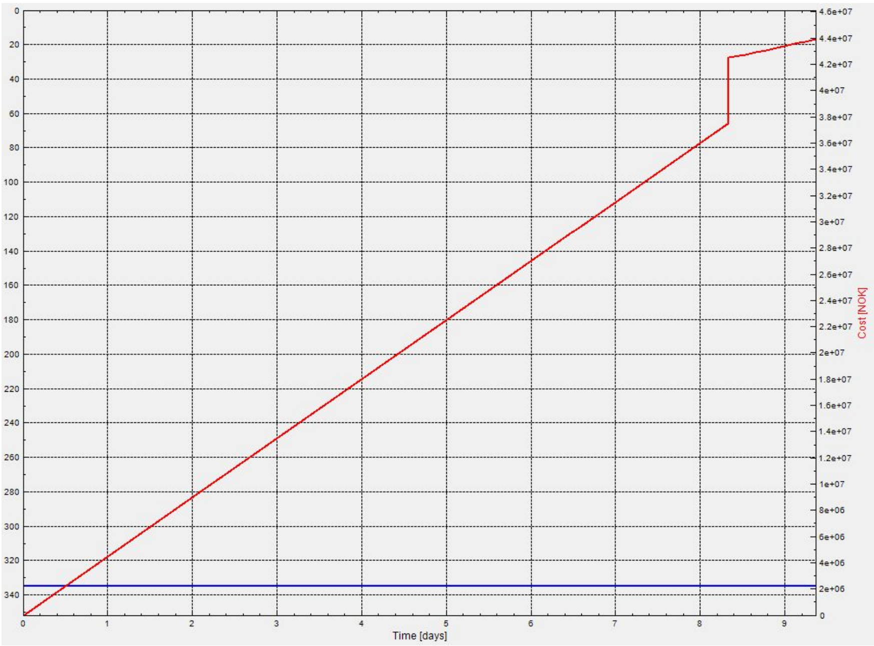


Figure 32. Case 2 Cost vs time plot

5.5.2. Batch Comparison

In the batch case scenarios besides comparing between case 1 batch and case 2 batch, different inputs for the rig and vessel rate are applied. This is to observe the impact of different daily rates. Different scenarios that can affect the total cost and duration will also be explained in the discussion section. As explained in the assumptions section, the batch case will compare only the Phase 3 of the P&A operation in addition with some operations to prepare the rig chase operation in case 2 and 2e. All of the results of the batch scenarios could be seen in **Appendix C.**

- **Cost and Duration Comparison**

  Besides the case 1 batch and 2 batch, two additional cases 1e batch and 2e batch are simulated with different daily rate. A single value of 10MNOK daily rate for semi submersible drilling rig and 1 MNOK daily rate for rig chase vessel are applied to see the effect of daily rate to the forecast. The results can be seen in these following tables and graphs.

It can be seen in **Table 16** and **Figure 33** that the cost forecast the two batch method has different outcome depending on the cost input. The daily rig and vessel cost assumption or data will determine which method will be the most cost effective. But besides cost consideration, choosing the second method could save rig time for drilling and completion purposes and also could reduce the WOW risk by choosing the optimal weather season fot the P&A operation.

Another fact is that the distances between the wells in the batch example considered are long. If the wells in the same close area the rig chase batch case would be more cost effective.

Table 16. Batch cases statistical values

Case Scenario	Method	Statistical Values							
		Cost (MNOK)				Duration (Days)			
		P10	P50	P90	Mean	P10	P50	P90	Mean
Case 1 Batch	Rig -Rig - Rig	46.693	50.611	54.582	50.621	10.5	11.3	12	11.3
Case 2 Batch	Rig - Rig - Rig Chase Vessel	52.532	56.128	59.746	56.141	14.3	15.1	15.9	15.1
Case 1e Batch	Rig -Rig - Rig	104.84	112.4	120.165	112.45	10.5	11.3	12	11.3
Case 2e Batch	Rig - Rig - Rig Chase Vessel	98.384	105.49	112.484	105.45	14.3	15.1	15.9	15.1

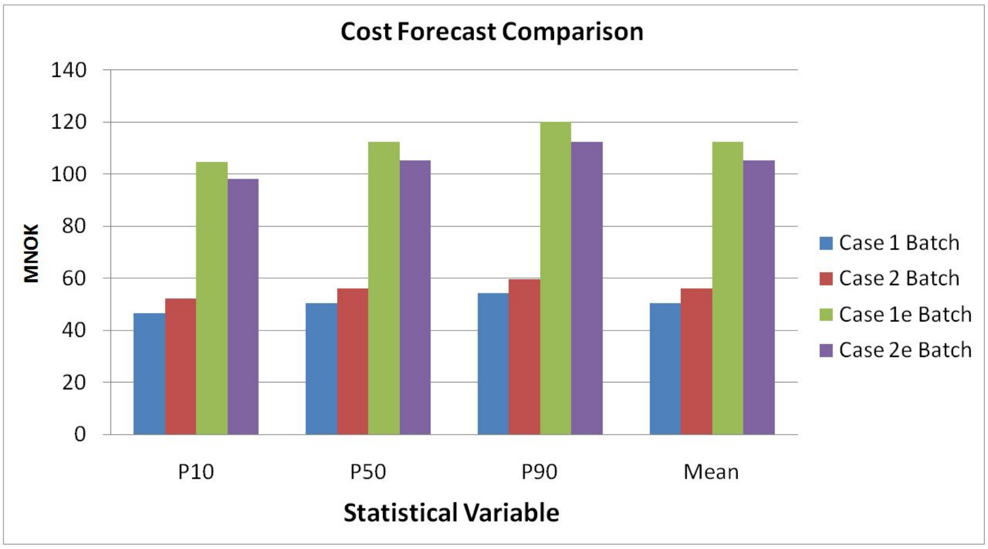


Figure 33. Batch cases cost forecast comparison

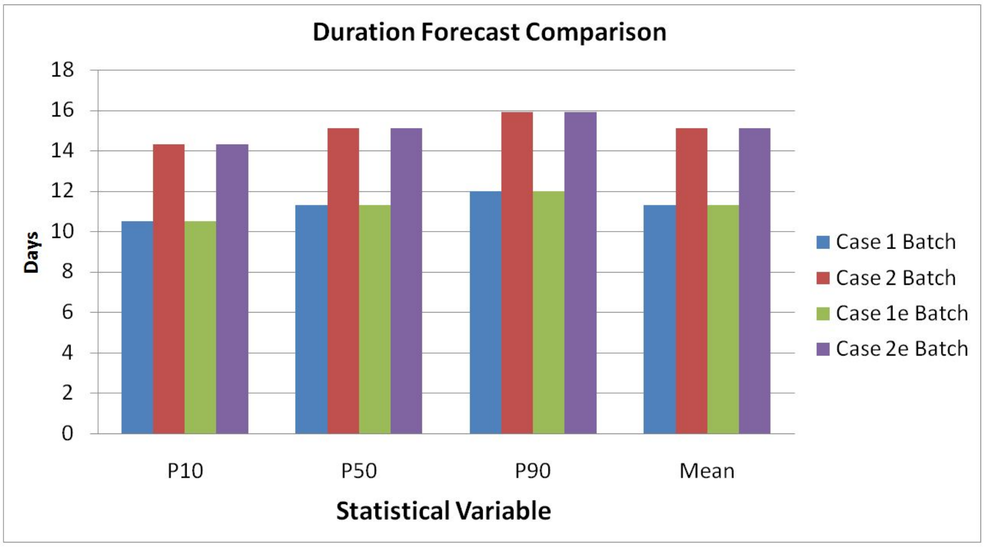


Figure 34. Batch cases duration forecast comparison

- **Phase Sensitivity Percentage**
  From the phase sensitivity result for the batch cases it could be seen that the pre-abandonment activities using the semisubmersible drilling rig gives the largest contribution to the time and cost of the total operation in batch 2 and 2e cases. These are the 4,5 and 6 event in the **Table 12**. More discussion will be given in the discussion section.

Figure 35. Case 2 batch cases cost forecast comparison

- **Cost vs Time Plot**
  From the cost and time plot of the batch 2 case shown in **Figure 36** it is clearly seen that for the P&A operation the majority of the cost and time is dominated by the pre-abandonment operations. Further discussion will be given in the discussion section.

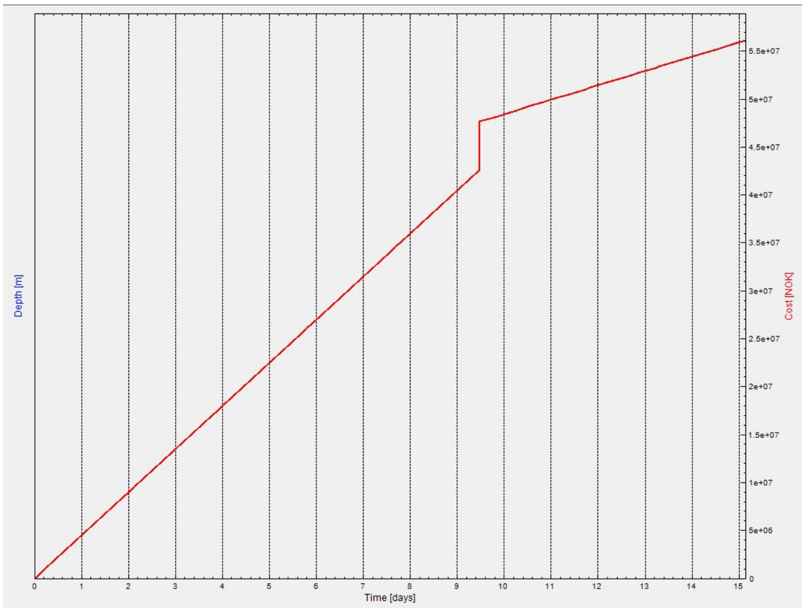


Figure 36. Case 2 batch cost vs time plot

5.6. Discussion

In this section, several points of discussion will be explained related to the simulation results. Although the input data and the assumption are based on ballpark values and general assumptions, there are several key findings that are informative for future simulation and P&A studies. These key discussion points will be explained in different subsections.

5.6.1. Cost and Duration Impact of Phase 2 Operation

From the method comparison cases statistical result displayed in **Table 15** and **Figure 29** and **31** with other phase sensitivity results in **Appendix C**, some interesting facts could be observed. Phase 2 dominates the duration and cost contribution of the final outcome. This is due to the long time used in the punch, circulate and plug operation conducted. In an actual case this could be even longer if there is a need of pulling out the tubing, washing bad cement, additional logging, casing milling etc.

Case 2 in the simulation was the most expensive for a single well operation, this is due to the phase 2 operation is done using the semi submersible drilling rig and additional mobilization cost of the vessel. The cost saving of finishing phase 3 with a rig chase vessel is not significant due to the small amount of time in the phase 3 operation.

On the other hand in case 3 and 4 mobilization cost and additional rig usage for pre-abandonment could be compensated by using an intervention vessel to finish majority of the P&A operation particularly phase 2. This is a huge potential considering the assumption of a single well, a batch scenario would favor the case 3 and 4 even more from the risk, cost and rig saving time point of view.

Case 3 and 4 is an ideal case on paper that could hugely improve P&A operations in the NCS, further technology development for reliability and multiple case capability is needed in order to have a robust full P&A operation using intervention vessel.

5.6.2. Factors that Affect Batch Operations

The batch case comparison results in **Table 16**, **Figure 33** and **34**, reveals interesting facts to be discussed. With the assumptions used in the simulation for the batch case 1 and 2 was observed that by using a full semi submersible rig is more cost effective compared to a combination of semi submersible rig and rig chase vessel. This is due to the additional pre-abandonment operation cost, mobilization cost and transit cost for the case 2 batch. One should note that these cases are based on an assumption for an exploration well case where the semi submersible rig is already in place after drilling and no mobilization and transit are required for the case 1 batch. However this picture may change in favor to any particular case if certain variables are different. The main variables are :

- **Rig daily rate**
  Case 1e and 2e is an example that different rig rates could result in different final outcome. By changing the rig rate assumptions the case 2e becomes more cost efficient compared to case 1e. The rig and vessel contract will be the main driving force of this variable. In an actual case a semi submersible drilling rig operation could turn out more expensive to operate daily due to the cost of the support system involved such as support vessels, helicopter, support center, etc.

- **Distance between wells**
  In the Bandung-32 Field example case the distance between wells will add the transit time resulting in additional cost for the case 2 batch operation. The distance between wells in an actual case could also add additional risk of delay due to bad weather. On the other hand batch operation in actual scenarios usually are done in one template resulting in a distance between wells which are close to zero. These are variables that will result in different final outcome and furthermore change the perspective when determining the batch method.

- **Number of wells**
  The number of wells in a batch operation will determine the final cost per well. A single call out/mobilization cost will be divided between the numbers of wells hence a lower cost per well will be obtained.

- **Risk factors consideration**
  Later explained in section 5.6.4., one of the advantage of the method using LWIV or Rig Chase Vessel is after the temporary abandonment by the semi submersible drilling rig the full P&A operation could be commenced in a chosen time throughout the year. By choosing what time the P&A operation will be done by the Rig Chase Vessel or LWIV, WOW risks could be reduced hence a lower mean cost and duration forecast. In this simulation an assumption that no WOW risks involved are used hence this factor is not accounted in the final result.

5.6.3. Semi Submersible Rig Time Saved

As mentioned before in chapter 2, one of the main purpose of doing more P&A operation with LWIV or Rig Chase vessel is to reduce use the semi submersible drilling rig activity for P&A operation. By reducing the use of semi submersible drilling rig in P&A operation, more drilling and completion operation can be performed which is the intended use of the semi submersibles. This is important since available rigs are scarce in the NCS and more exploration and field development are needed. Although some cases could be more expensive, the need of drilling and completion with a semi submersible could overcome the cost consideration when choosing a method.

From the time and cost data, rig and vessel use for every case could be obtained and furthermore compiled for comparison. Here below on **Table 17** and **Figure 37** are the semi submersible rig time saved per well is presented in table and graph.

Table 17. Semi submersible rig time saved per well

Case Scenario	Method	Time Used (Days)			Semi Submersible Rig Saving Time per Well Relative to Case 1 (Days)
		Semi Submersible Drilling Rig	RLWI / Rig Chase	Total Time	
Case 1	Rig -Rig - Rig	8.7	0	8.7	0
Case 2	Rig - Rig - Rig Chase Vessel	8.3	1.1	9.4	0.4
Case 3	Rig - LWIV - LWIV	4.4	5.9	10.3	4.3
Case 4	LWIV - LWIV - LWIV	3.2	7.8	11	5.5

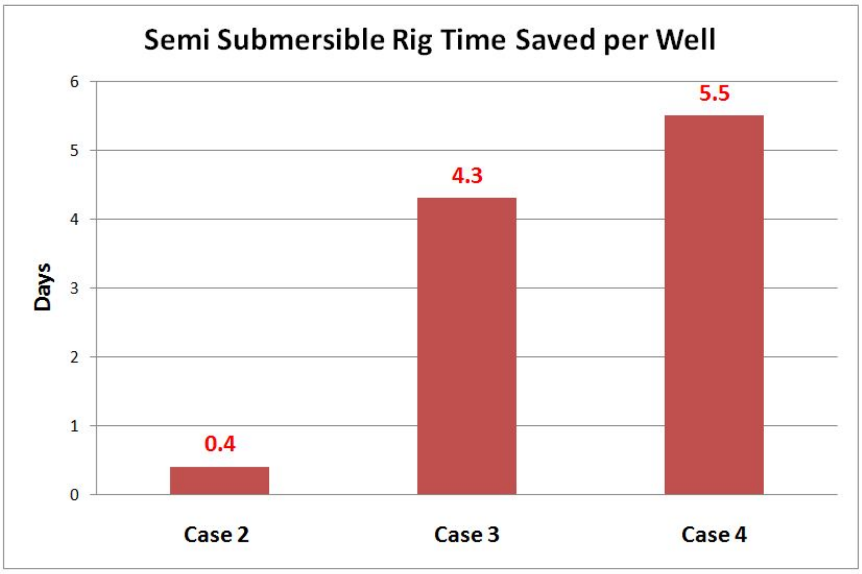


Figure 37. Semi submersible rig time saved per well comparison

5.6.4. P&A Operation Timing to Reduce Operation Risks

Weather is an important element in subsea operations due to the high operation demand with respect to conducting safe operations within operational limits. As discussed before in section 2.5.1., for an unsafe and technically unfeasible weather condition an intentional delay of operation known as Waiting on Weather (WOW) will be induced.

The probability of this weather condition to occur varies throughout the year by the seasonal changes. To reduce the probability of WOW a well could be suspended temporary by the semi submersible drilling rig for later to be reentered with LWIV or rig chase vessel in a time where the WOW possibility is the lowest to fully complete the P&A. Shown in **Figure 8** on page 23 is the wave height and its probability to occur throughout the year. These types of data are used to determine the optimal time for the operation.

6. Conclusions and Recommendations

The research, simulation and work in this thesis has revealed several interesting facts that could improve the cost, duration, method, etc. of permanent P&A operation specifically in subsea exploration wells. Furthermore the use of RiskE software for P&A operation forecast also reveals potential room for the software improvement.

This chapter will cover the conclusions and recommendations based on the previous chapters in this thesis.

6.1. P&A Cost and Duration Estimation

After analyzing the simulation forecast results, a few findings are revealed. The fact that the cost and duration difference is relatively insignificant between using rig-less or rig-based method shows that there is no importance for an oil company to change semi submersible rig P&A operation to a vessel P&A operation for a single exploration well. In the future when intervention vessel could handle the full P&A operation in a safe and reliable manner, a full P&A operation will be commercially and technically possible and the cost and duration could be reduced.

On the other hand, choosing a method with a perspective other than cost and duration could bring advantages for the oil company such as additional semi submersible rig time for drilling and completion activities and reduced operational risks. With the batch operation, vessels could perform P&A for several different operators using the concept of integrated operations. This would reduce the operational cost per well for the P&A operation.

Several points of recommendation with respect to the findings explained above to improve the cost, duration and general permanent P&A operation are:

- **Improve the reliability and technology for Intervention vessels to fully commence P&A operation focusing on the Phase 2 operation.**
  Commencing the phase 2 of the P&A operation by vessels is a potential cost and duration saving since this phase takes the longest time to finish. By improving the technology and reliability of the vessels in the market, field operators will not hesitate to use vessels to do full P&A operation since current technology still raise some robustness doubt in the market. Further advantages of using vessels are explained in the other points.

- **Promoting more use of vessels to do P&A operations to save more rig time for primary drilling operations.**
  By using vessels to commence P&A operations, rigs could be used more to do drilling and completion of exploration and development wells. This is essential in a time where rig contracts are expensive and scarce and oil prices are high. More rig time should be used for its main function which is drilling and completing wells.

- **Promoting more use of vessel to do P&A operations after a temporary suspension to reduce operational risks such as waiting on weather by commencing the operation in a chosen time interval.**
  Weather is one of the main challenges of oil and gas activity in the North Sea. By suspending a planned P&A well after drilling and commencing the full P&A operation in a chosen time throughout the year the probability of delay caused by waiting on weather could be reduced.

- **Increase the number of wells in batch operation by integrating P&A operations to reduce the cost of P&A per well.**
  The number of wells in a batch P&A operation will reduce the P&A cost per well. This could be accomplished by integrating P&A operations from different oil companies or fields. This task will not be easy considering the different contracts and relations between oil companies and more involvement from the governing authorities are needed.

6.2. RiskE Software for P&A Operation Forecasting

RiskE software was initially developed to forecast cost and duration for drilling operation. In this thesis the software is used to forecast various scenario of a P&A operation. This uncommon use of the RiskE software exposed some of the potential and room for improvement within RiskE for P&A application uses, such as:

- The RiskE software could be used for P&A forecasting without major changes. The flexibility to alter the automatically generated operation play by deleting existing or inserting new user defined makes this possible. The user can name these operations accordingly and specify appropriate input regarding duration and cost distribution. This is a key feature in RiskE to simulate customized operations which differ from a normal drilling operation.

- In drilling, a time and depth curve is essential to display how far the operation has commenced relative to the time. However, in P&A, the progress of the operation is not reflected by depth. Another way of displaying this is to add a time vs % P&A operation completion curve as an additional output.

- In the Mobilize Rig Technology input phase an addition of Intervention Vessel and Rig Chase Vessel could be a useful addition for RiskE with specific characteristics of a vessel such as speed, etc.

- In the RiskE phase and operation sensitivity results, it is seen that if the naming of the phase/operation is longer then a certain length, only partially the name is displayed. A display that enables the user to see all the naming will be a useful change for RiskE.

- An addition of a phase editor for a Phase 1, 2 and 3 P&A besides the existing drilling, mobilize, spudding, BOP and abandon and furthermore an automatic operation generator for the respective P&A phases will be a useful addition for RiskE. An addition of a customized phase editor that could cover all types of operations and automatically generate the most common operations cold also be added.

6.3. Recommendation for Future Studies

There are several points that can improve future studies in cost and duration P&A forecast with respect to the topics discussed in this thesis, such as :

- Studies on more detailed and accurate operation procedures and their respective input distribution for forecasting cost and duration in P&A cases.

- Studies on risks involved in P&A operation and implement the study in the RiskE-risk operation plan for a better risk based cost and duration forecast.

- Further cost and duration simulation including sensitivity analysis. Variables such as rig cost, well distance, number of wells, etc. should be varied to study their effects on cost and duration of a P&A operation.

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15. Personal Contact with Service Company officially obtained permission with requirement of the anonymous location and change of data values in the figure

Appendix A

Additional Well Barrier Elements (WBEs) Acceptance Criteria – NORSOK [3]

No.	Element name	Additional features, requirements and guidelines
Table 2	Casing	Accepted as permanent WBE if cement is present inside and outside.
Table 22	Casing cement	Accepted as a permanent WBE together with casing and cement inside the casing. Should alternative materials be used for the same function a separate WBEAC shall be developed.
Table 24	Cement plug	Cased hole cement plugs used in permanent abandonment shall be set in areas with verified cement in casing annulus. Should alternative materials be used for the same function a separate WBEAC shall be developed. A cement plug installed using a pressure tested mechanical plug as a foundation should be verified by documenting the strength development using a sample slurry subjected to an ultrasonic compressive strength analysis or one that have been tested under representative temperature and/or pressure.
Table 25	Completion string	Accepted as permanent WBE if cement is present inside and outside the tubing.
Table 43	Liner top packer	Not accepted as a permanent WBE.

Table 2 – Casing Acceptance Criteria – NORSOK [3]

Features	Acceptance criteria	See
A. Description	This element consists of casing/liner and/or tubing in case tubing is used for through tubing drilling and completion operations.	
B. Function	The purpose of casing/liner is to provide a physical hindrance to uncontrolled flow of formation fluid or injected fluid between the bore and the back-side of the casing.	
C. Design construction selection	1. Casing-/liner strings, including connections shall be designed to withstand all pressures and loads that can be expected during the lifetime of the well including design factors. 2. Minimum acceptable design factors shall be defined for each load type. Estimated effects of temperature, corrosion and wear shall be included in the design factors. 3. Dimensioning load cases with regards to burst, collapse and tension/compression shall be defined and documented. 4. Casing design can be based on deterministic, probabilistic or other acceptable models.	ISO 11960 API Bull 5C3 API Bull 5C2
D. Initial test and verification	1. Casing/liner shall be leak tested to maximum anticipated differential pressure. 2. Casing/liner that has been drilled through after initial leak test shall be retested during completion activities.	
E. Use	1. Casing/liner should be stored and handled to prevent damage to pipe body and connections prior to installation.	ISO 10405 API Bull 5C2
F. Monitoring	1. The A annulus shall be continuously monitored for pressure anomalies. Other accessible annuli shall, if applicable be monitored at regular intervals. 2. If wear conditions exceed the assumptions from the casing-/liner design, indirect or direct wear assessment should be applied (e.g. collection of metal shavings by use of ditch magnets and wear logs).	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leaking casing/liner.	

Table 22 – Casing Cement Acceptance Criteria – NORSOK [3]

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 **General:** Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 **Conductor**: No requirement as this is not defined as a WBE. 5.3 **Surface casing**: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 **Casing through hydrocarbon bearing formations**: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class 'G'
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for "wellhead"
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

Table 24 – Cement Plug Acceptance Criteria – NORSOK [3]

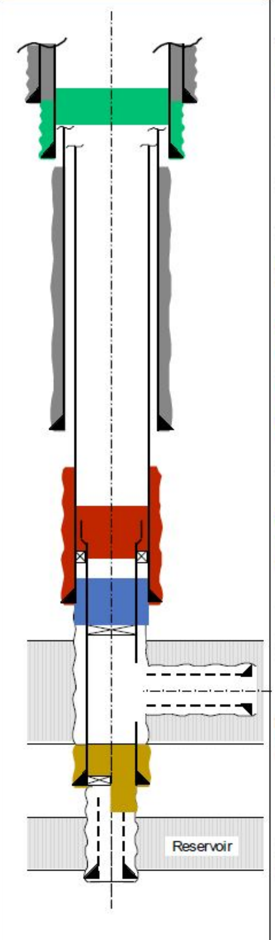
<table>
<tr><th>Features</th><th>Acceptance criteria</th><th>See</th></tr>
<tr><td>A. Description</td><td>The element consists of cement in solid state that forms a plug in the wellbore.</td><td></td></tr>
<tr><td>B. Function</td><td>The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.</td><td></td></tr>
<tr><td>C. Design, construction and selection</td><td>1. A design and installation specification (cementing program) shall be issued for each cement plug installation.
2. The properties of the set cement plug shall be capable to provide lasting zonal isolation .
3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration.
4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole
5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads.
6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole.
7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD.
8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe.
9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.</td><td>API Standard 10A Class 'G'</td></tr>
<tr><td>D. Initial verification</td><td>1. Cased hole plugs should be tested either in the direction of flow or from above.
2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure.
3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.).
4. Its position shall be verified, by means of:
<table>
<tr><th>Plug type</th><th>Verification</th></tr>
<tr><td>Open hole</td><td>Tagging, or measure to confirm depth of firm plug.</td></tr>
<tr><td>Cased hole</td><td>Tagging, or measure to confirm depth of firm plug
Pressure test, which shall
a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and
b. not exceed casing pressure test, less casing wear factor which ever is lower
If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.</td></tr>
</table></td><td></td></tr>
<tr><td>E. Use</td><td>Ageing test may be required to document long term integrity.</td><td></td></tr>
<tr><td>F. Monitoring</td><td>For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.</td><td></td></tr>
<tr><td>G. Failure modes</td><td>Non-compliance with above mentioned requirements and the following:
a. Loss or gain in fluid column above plug.
b. Pressure build-up in a conduit which should be protected by the plug.</td><td></td></tr>
</table>

Table 25 – Completion String – NORSOK [3]

Features	Acceptance criteria	See
A. Description	This element consists of tubular pipe.	
B. Function	The purpose of the completion string as WBE is to provide a conduit for formation fluid from the reservoir to surface or vice versa.	
C. Design, construction and selection	1. All components in the completion string (pipe/housings and threads) shall have gas tight connections whenever exposed to hydrocarbons during its lifetime. 2. Dimensioning load cases shall be defined and documented. 3. The weakest point(s) in the string shall be identified. 4. Minimum acceptable design factors shall be defined. Estimated effects of temperature, corrosion, wear, fatigue and buckling shall be included in the design factors. 5. The tubing should be selected with respect to • tensile and compression load exposure, • burst and collapse criteria, • tool joint clearance and fishing restrictions, • tubing and annular flowrates, • abrasive composition of fluids, • buckling resistance, • metallurgical composition in relation to exposure to formation or injection fluid, • HPHT: Strength reduction due to temperatures effects.	
D. Initial test and verification	1. Pressure testing to METP. 2. HPHT: The tubular load bearing component of the completion string should be MPI inspected prior to HPHT exposure.	
E. Use	1. Stab-in safety valve and one way check valve for all type of connections exposed at the drill floor shall be readily available when the completion string is located inside the BOP.	
F. Monitoring	1. Pressure integrity is monitored through the annulus pressure.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Leak to or from the annulus.	

WBS - Permanent Abandonment – Multibore with Slotted Liner/Sandscreens

9.8.5 Permanent abandonment - Multibore with slotted liners or sand screens

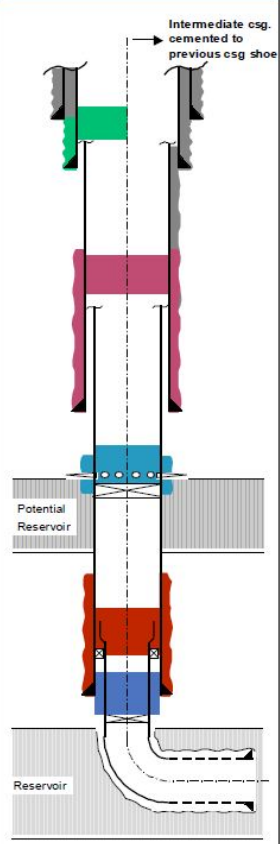


Well barrier elements	See Table	Comments
Barrier between reservoirs		
1. Casing cement	22	
2. Cement plug	24	Cased hole.
or,		
2. Cement plug	24	Transition plug across casing shoe.
Primary well barrier		
1. Cement plug	24	Across wellbore and casing shoe.
Secondary well barrier, reservoir		
1. Casing cement	22	
2. Cement plug	24	Casing plug across liner top.
Open Holes to surface wellbarrier		
1. Cement plug	24	Cased hole cement plug.
2. Casing cement	22	Surface casing.

Notes
1. The “well barrier between reservoirs” may act as the primary well barrier for the “deep” reservoir, and “primary well barrier” may be the secondary well barrier for “deep” reservoir, if the latter is designed to take the differential pressures for both formations.
2. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, as applicable in each case.

WBS - Permanent Abandonment – Slotted Liners in Multiple Reservoirs

9.8.6 Permanent abandonment - Slotted liners in multiple reservoirs



Well barrier elements	See Table	Comments
Primary well barrier, deep reservoir		
1. Cement plug	24	Through liner and across casing shoe/Open hole transition.
Secondary well barrier		
1. Casing cement	22	
2. Cement plug	24	Across liner top.
Primary well barrier, shallow reservoir		
1. Cement plug	22	Squeezed into perforated casing annulus above potential reservoir.
Secondary well barrier, shallow reservoir		
1. Casing cement	22	
2. Cement plug	24	
Open holes to surface well barrier		
3) Cement plug	24	Cased hole.
4) Casing cement	22	Surface casing.

Notes
1. Secondary well barrier shall not be set higher than the formation integrity at this depth, considering that the design criteria may be initial reservoir pressure, which may develop over time.
2. The case on the right hand side indicates that the intermediate casing string is cemented into surface casing, i.e. with no open annulus to surface. Hence, no open holes to surface well barrier is required.

Appendix B

Intervention Vessel Specification

ISLAND INTERVENTION – ISLAND OFFSHORE
(Source http://www.islandoffshore.com/?cid=91#cid=91)

Type:	RLWI (Riserless light well intervention unit) - DPIII
Design:	Ulstein SX 121
Yard:	Ulstein Verft AS
Year:	2011
Class:	DNV + 1A1 with the following class notations: R Ship-shaped Well Intervention Unit, SF, E0, DYNPOS-AUTRO, NAUT-OSV (A), CLEAN DESIGN, OPP-F, CRANE, COMF-V(3), COMF-C(3), LFL*, DK(+), HL(2,8), HELIDK.
L.O.A.:	120,2m
Width:	25,0m
DW:	8700T / 7,9m
Deck area:	1.400m2 10 t/m2 main deck
	380m2 5 t/m2 mezzanine deck
Accomodation:	100 persons
Subsea crane:	140T
Moonpool:	8x8m
	Tower with guide wire winches
	Main winch capacity
	140t @ 0 - 1500m water depth
	115t @ 1500 - 2500m water depth
	Skidding system
	2xWork ROV w/heavy weather LARS

The Island Intervention has been designed as a light well intervention and subsea construction vessel. The vessel is capable to meet and fulfill the toughest requirements in the industry, and has already experience from several types of subsea projects not limited to the below:

- P&A work
- Construction work
- Tower and module handling
- Installation work
- IMR work
- Survey work
- Crane work
- Diving work

Rig Chase Vessel Specification

MV ISLAND VALIANT – ISLAND OFFSHORE
(Source http://www.islandoffshore.com/?cid=91#cid=25)

Type:	AHTS - Light construction vessel - DP2
Design:	UT 787 LCD
Yard:	Aker Yards Langsten
Year:	2007
Class:	DnV+1A1, SF, E0, DK(+), HL(p), LFL*, ICE C, TUG, DynPos AutR, CLEAN, T-MON, BIS, COMF-V(3), DEICE, SUPPLY VESSEL.
L.O.A.:	93,30m
Width:	22,0m
DW:	4200t
Deack Area:	860m2
Accomodation:	60
A-frame:	200t (100t ahc) fitted above moonpool
ROV:	A 170hp work ROV permanent installed in a garage with heavy weather LARS system
Subsea Crane:	90t ahc (SWL 110t)
Coursor System:	A Cursor and guide wire system could be fitted to the vessel

The Island Valiant has been designed as a large AHTS vessel with Subsea installation and light Construction vessel capabilities.
The vessel is capable to meet and fulfil the toughest requirements in the industry, and has already experience from several
Heavy duty projects not limited to the below;

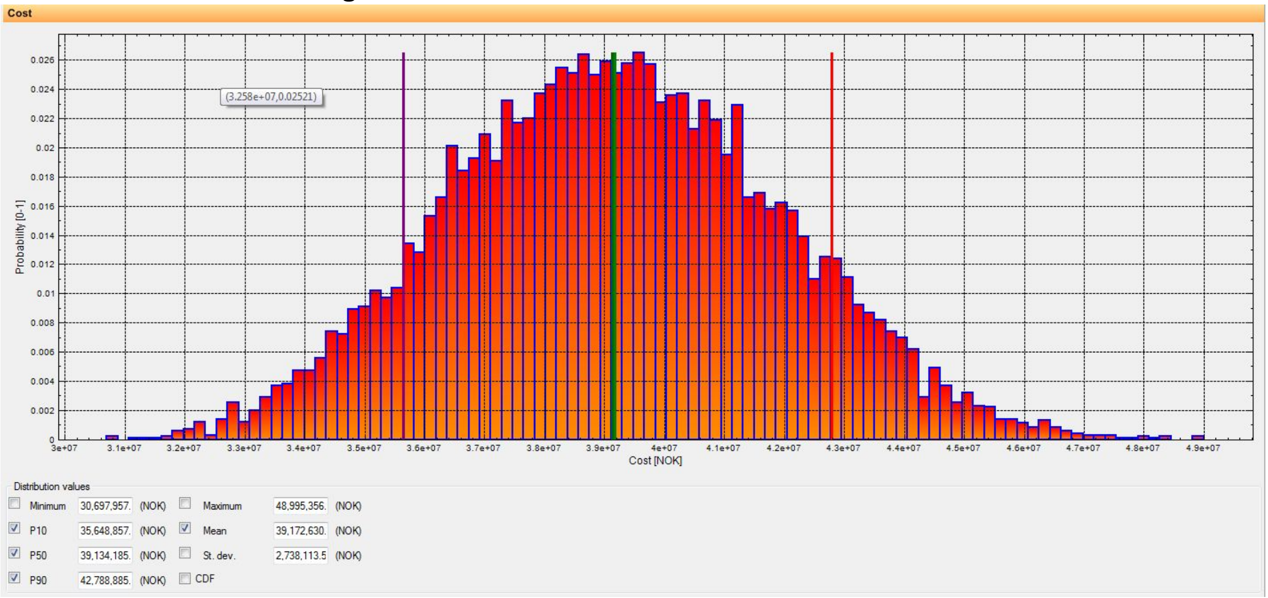
- Deep water anchor handling with fully integrated work ROV support.
- Heavy duty mooring and subsea Installation work
- Pre-laying of chain and synthetic rope at deep water
- Trenching work
- Light construction work
- P&A work
- Tower work
- Drill pipe handling through moonpool
- Mooring Installation work at deep water
- MR work
- Survey work
- Crane work
- ROV Work

The Island Valiant has been built for world wide operation, and is presently trading the North Sea Spot and Project market.

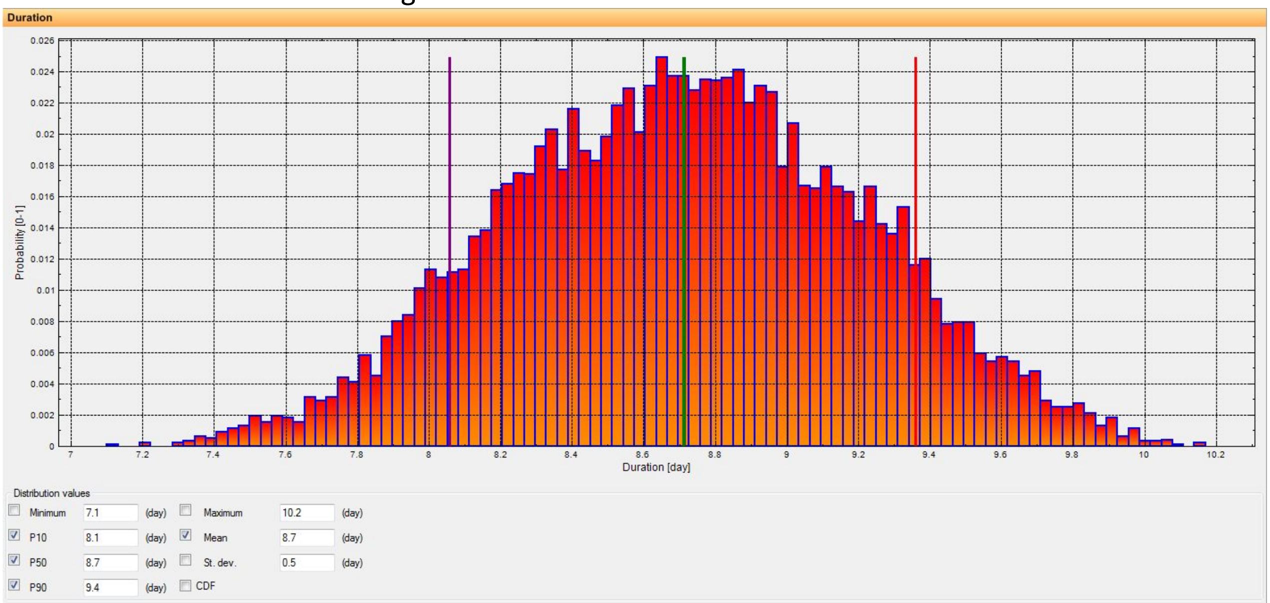
Appendix C

Case 1 Histograms and Graphs

Case 1 Cost Forecast Histogram

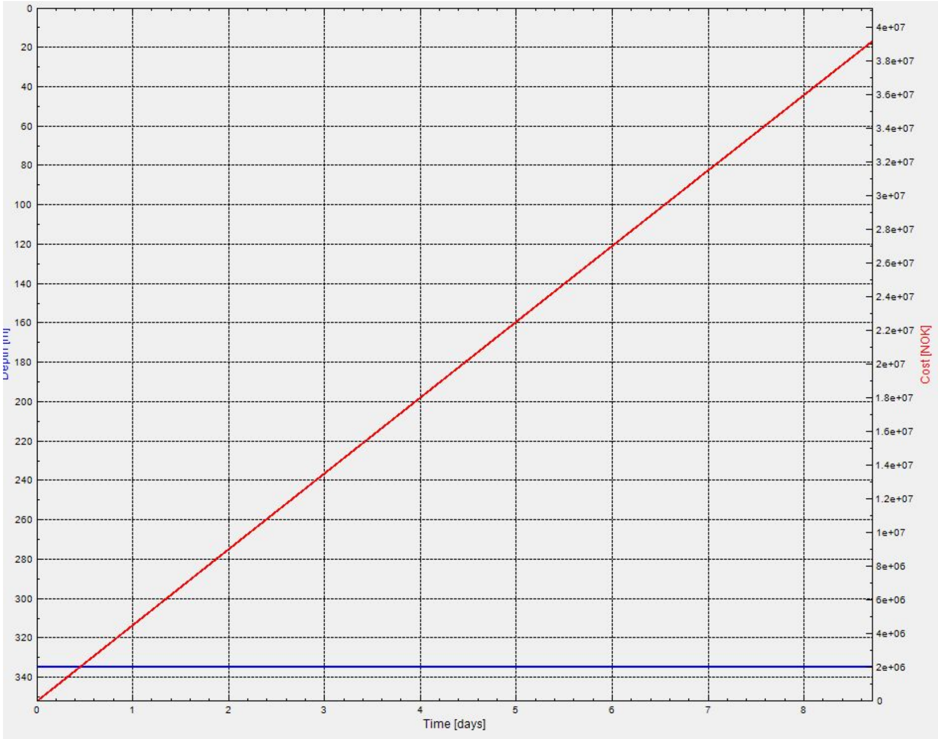


Case 1 Duration Forecast Histogram



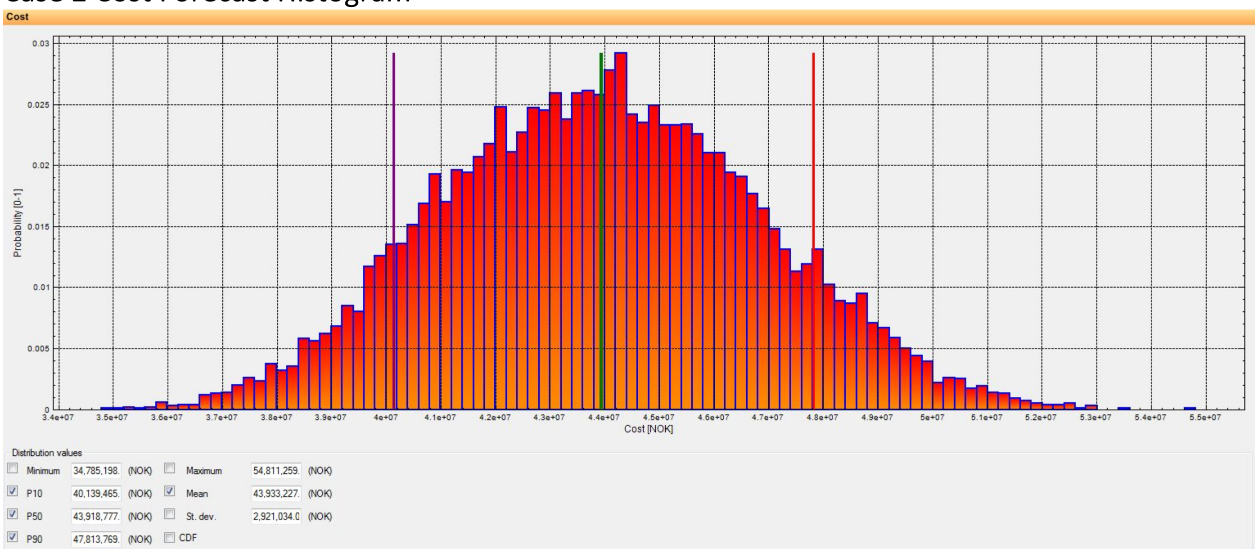
Case 1 Phase Sensitivity Percentages

Case 1 Time and Cost Graph

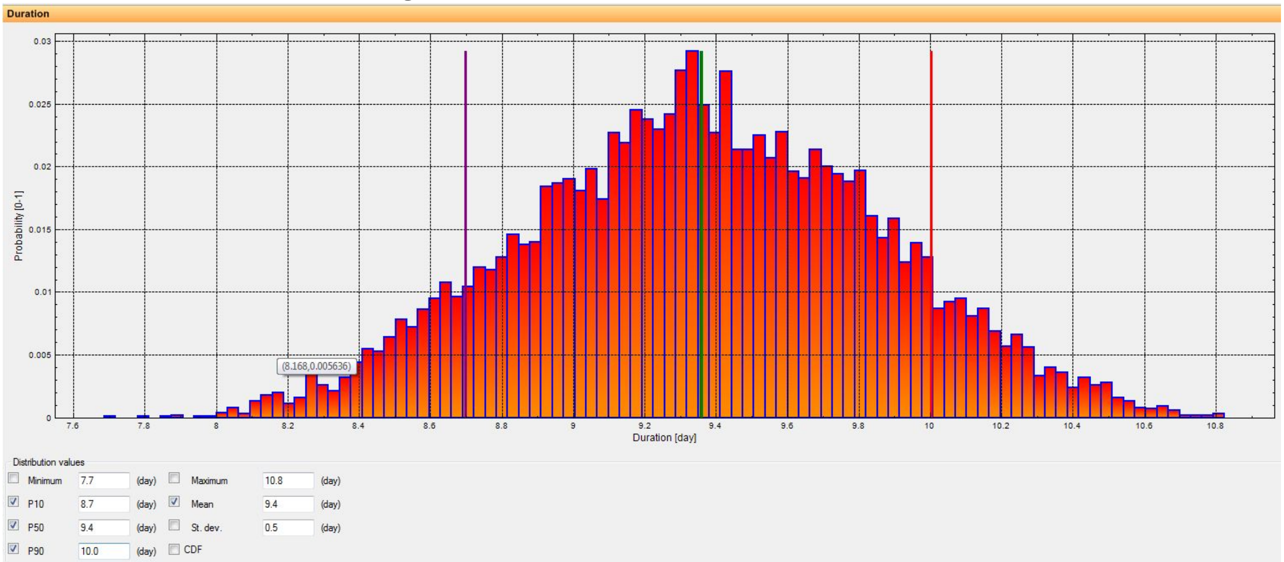


Case 2 Histograms and Graphs

Case 2 Cost Forecast Histogram

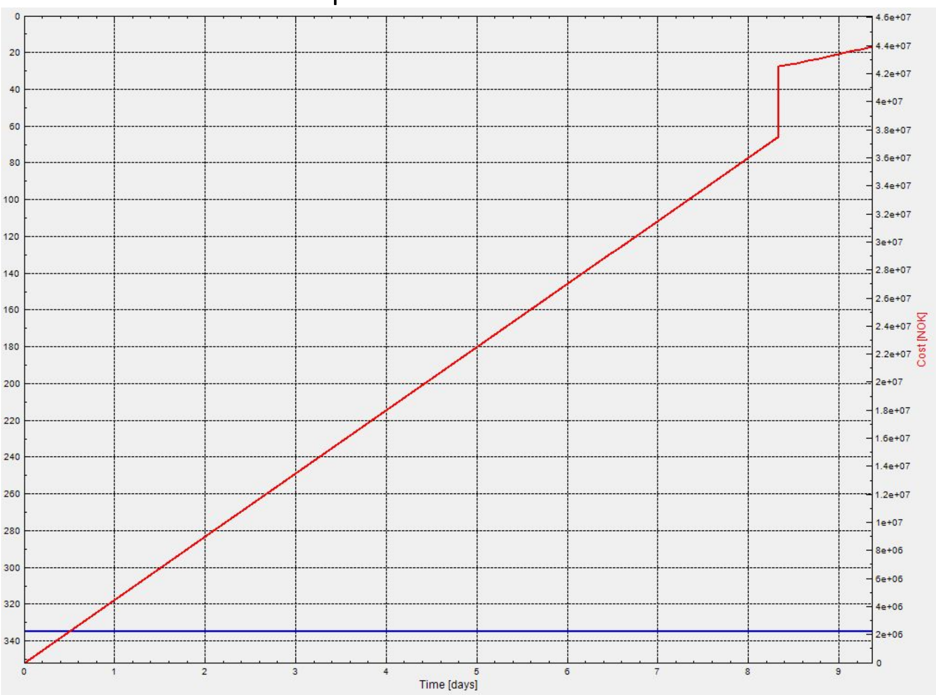


Case 2 Duration Forecast Histogram



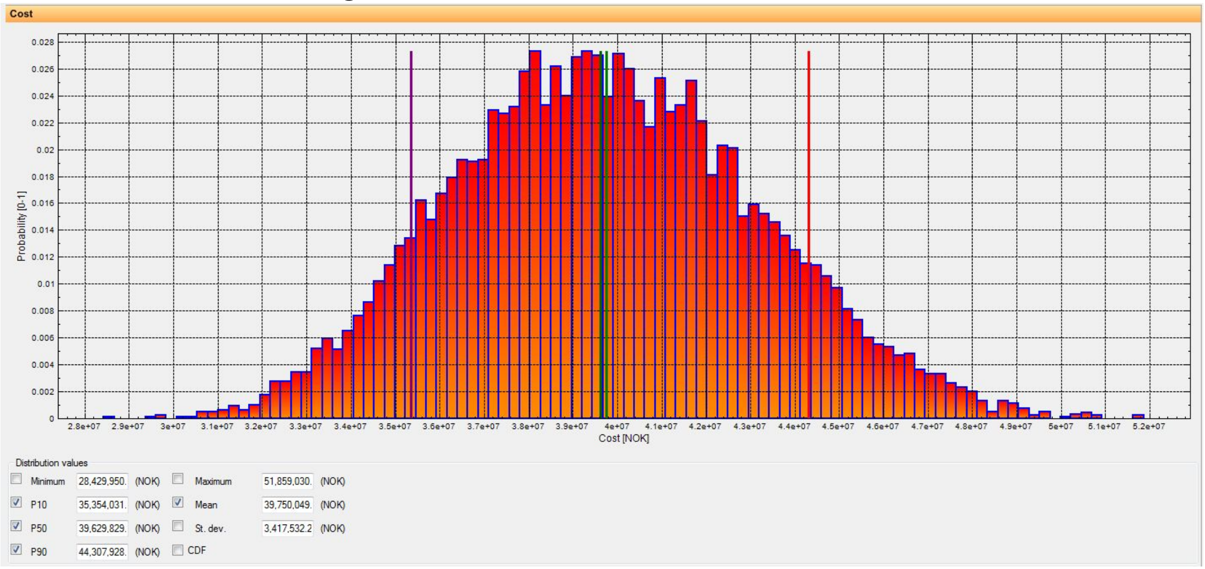
Case 2 Phase Sensitivity Percentages

Case 2 Time and Cost Graph

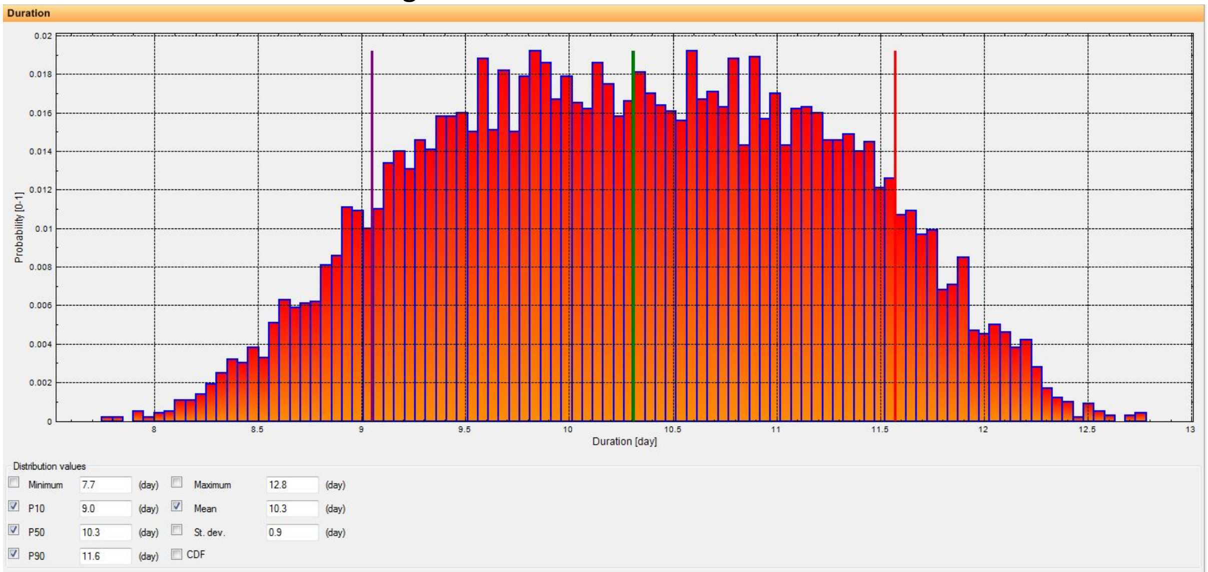


Case 3 Histograms and Graphs

Case 3 Cost Forecast Histogram

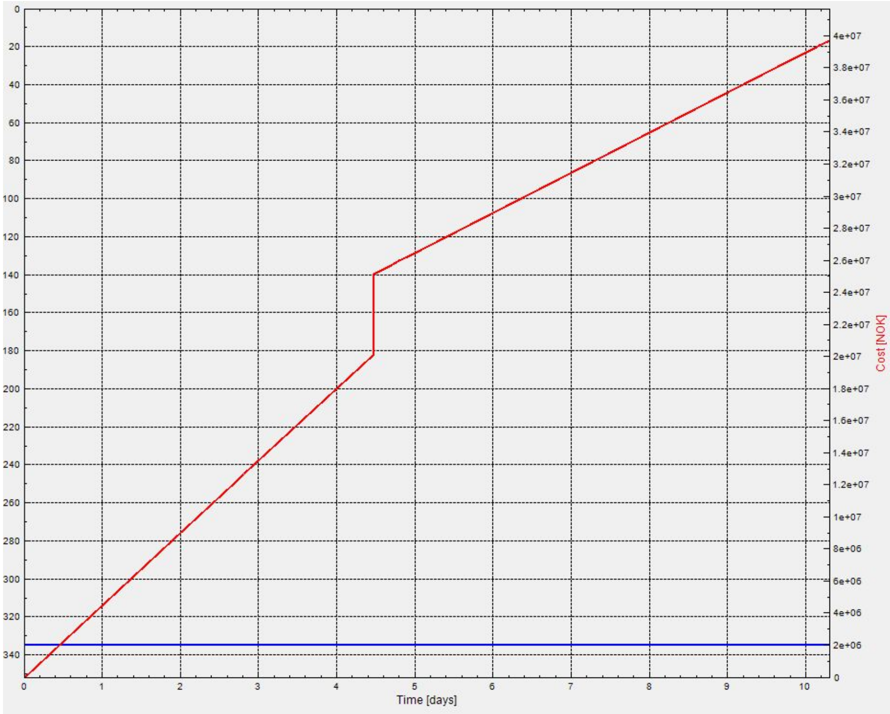


Case 3 Duration Forecast Histogram



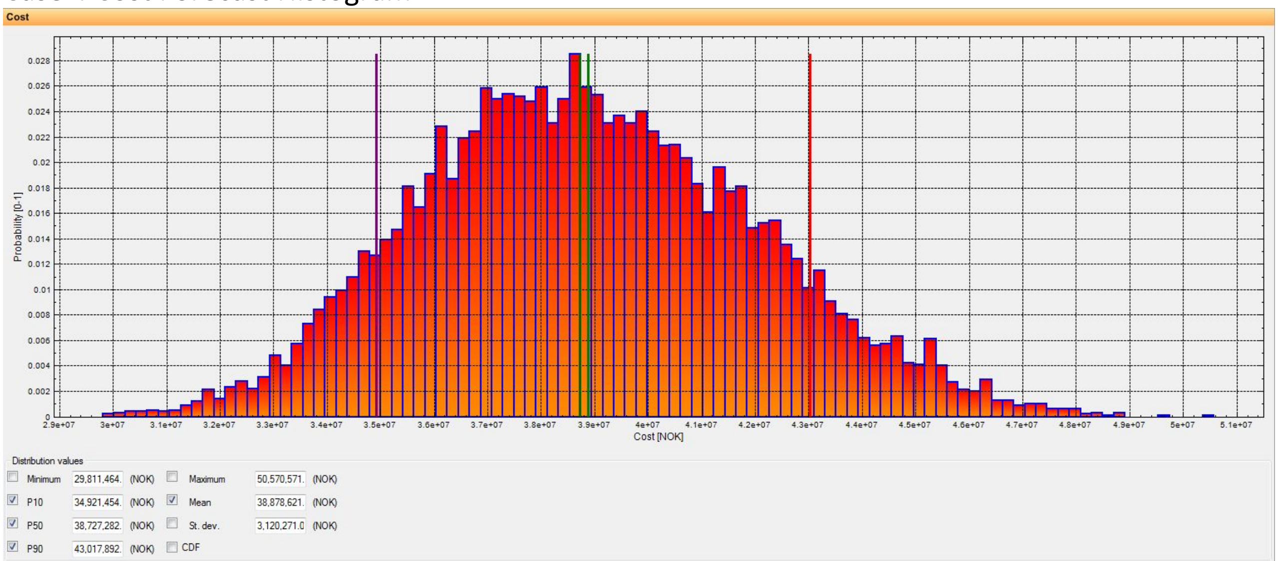
Case 3 Phase Sensitivity Percentages

Case 3 Time and Cost Graph

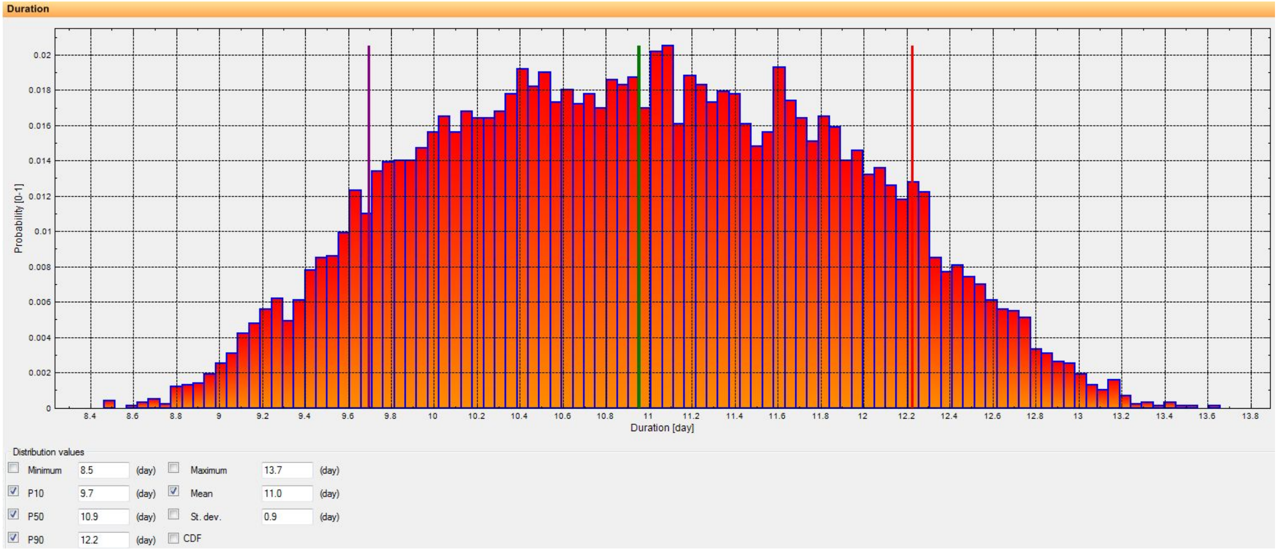


Case 4 Histograms and Graphs

Case 4 Cost Forecast Histogram

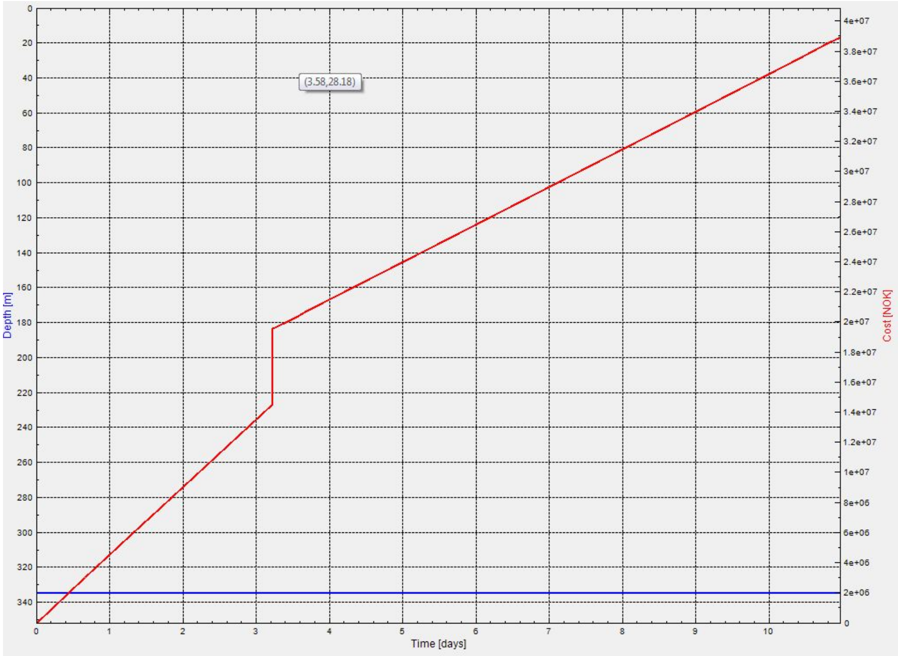


Case 4 Duration Forecast Histogram



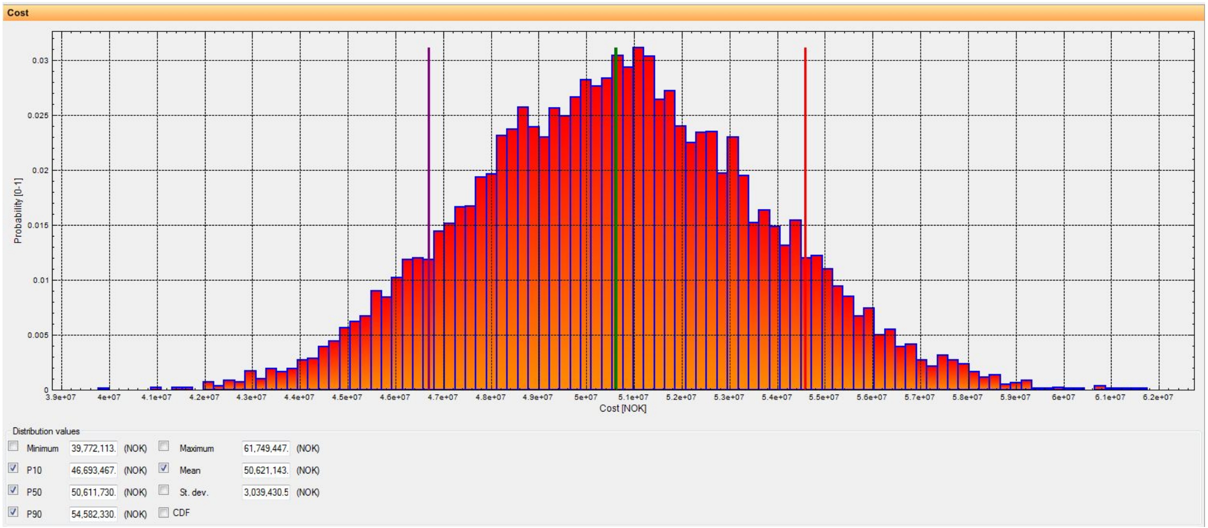
Case 4 Phase Sensitivity Percentages

Case 4 Time and Cost Graph

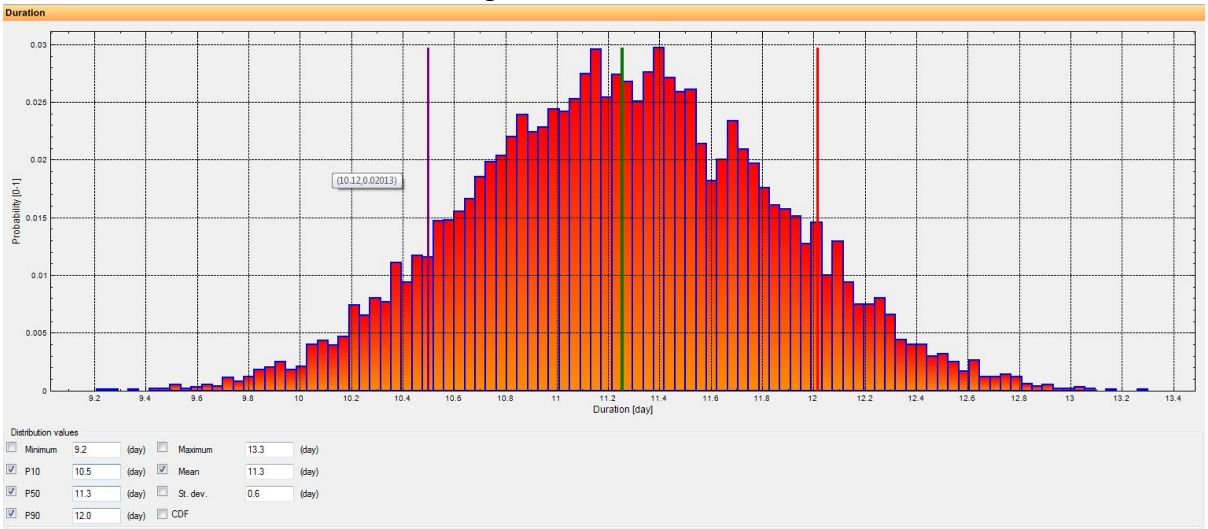


Case 1 Batch Histograms and Graphs

Case 1 Batch Cost Forecast Histogram

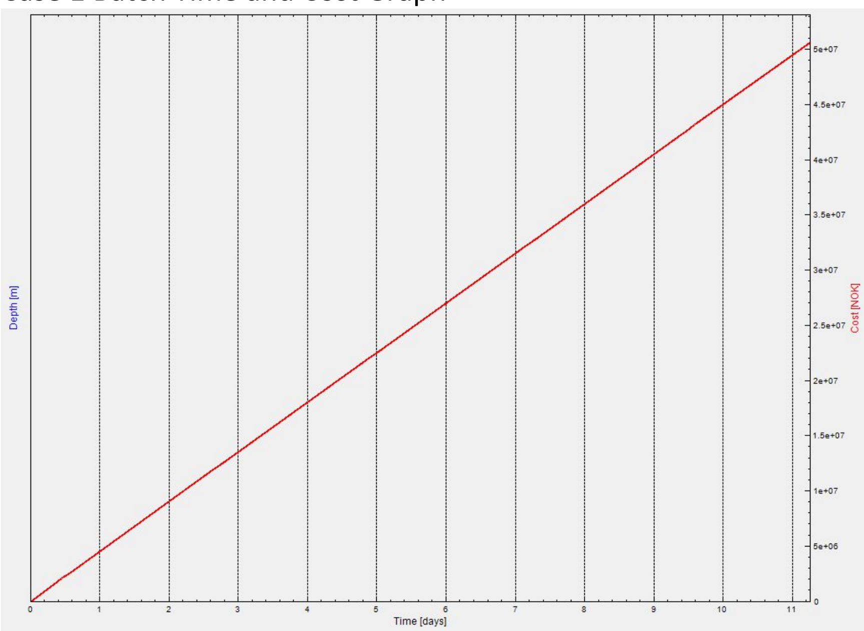


Case 1 Batch Duration Forecast Histogram



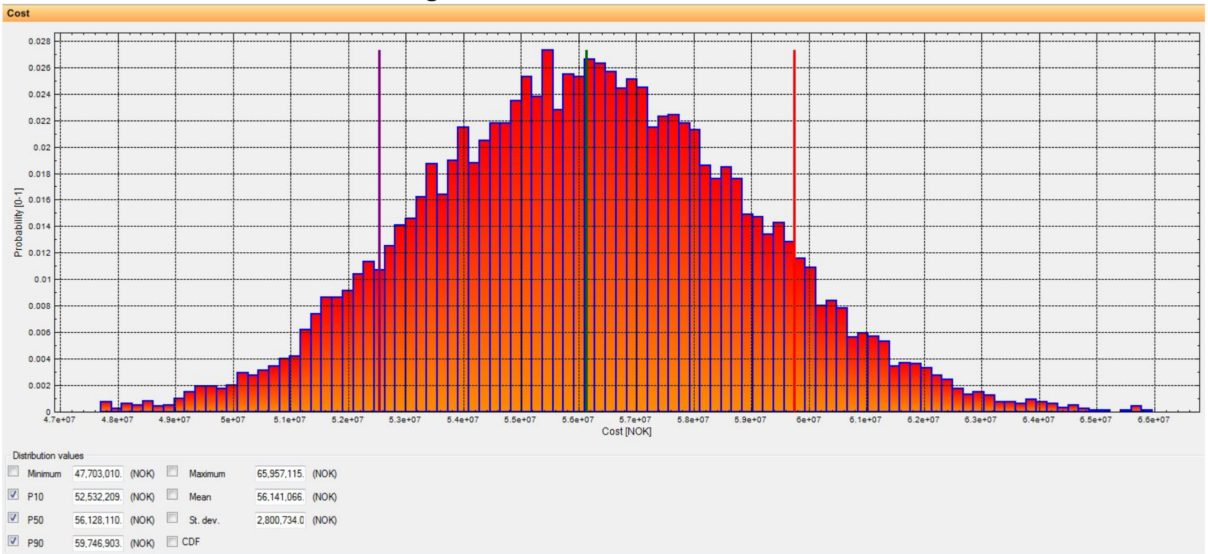
Case 1 Batch Phase Sensitivity Percentage

Case 1 Batch Time and Cost Graph

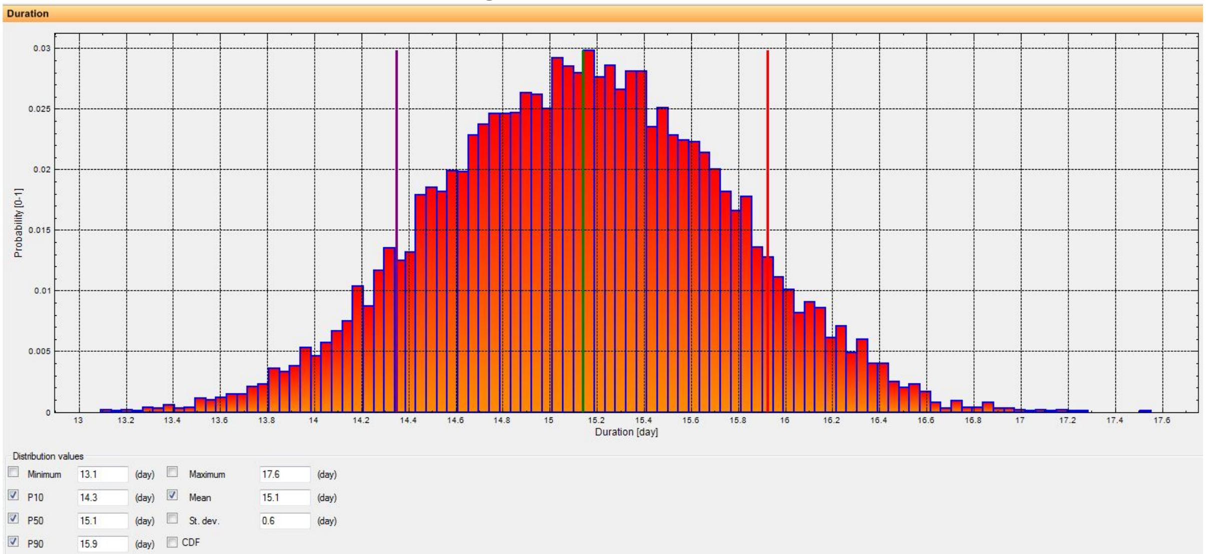


Case 2 Batch Histograms and Graphs

Case 2 Batch Cost Forecast Histogram

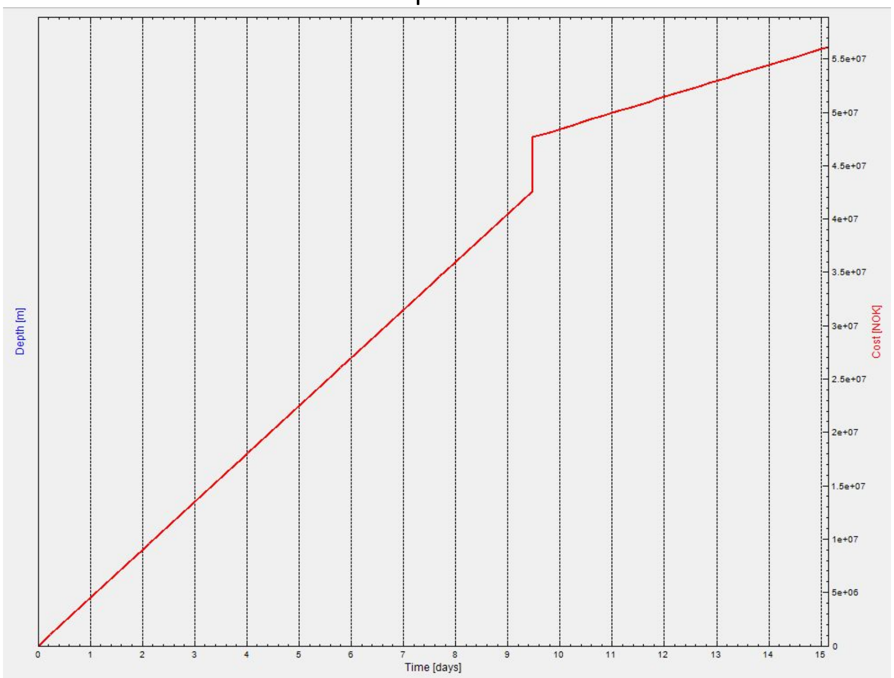


Case 2 Batch Duration Forecast Histogram



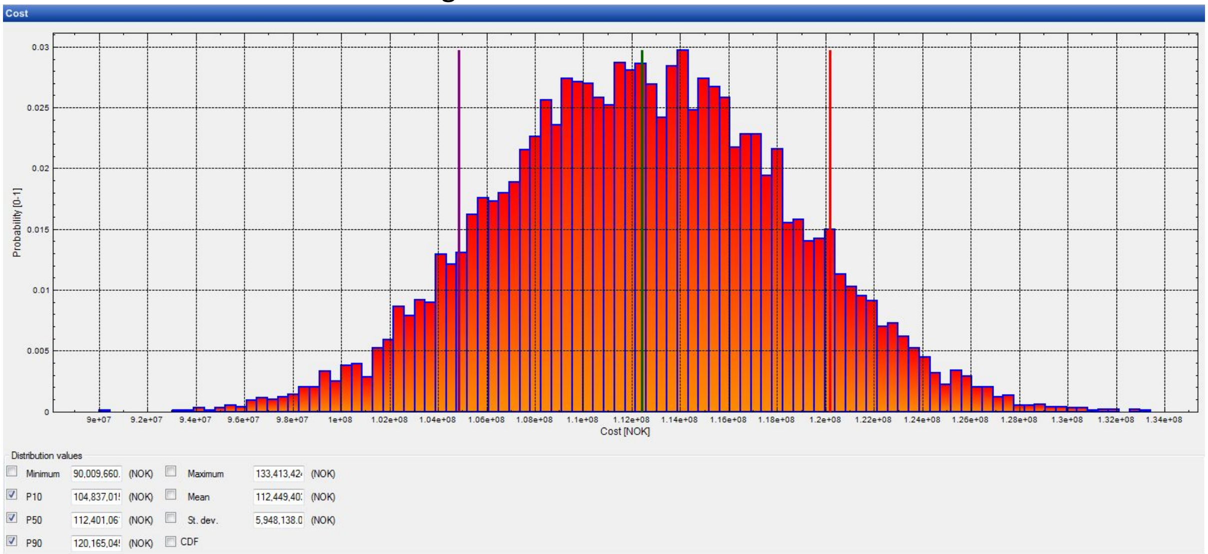
Case 2 Batch Phase Sensitivity Percentages

Case 2 Batch Time and Cost Graph

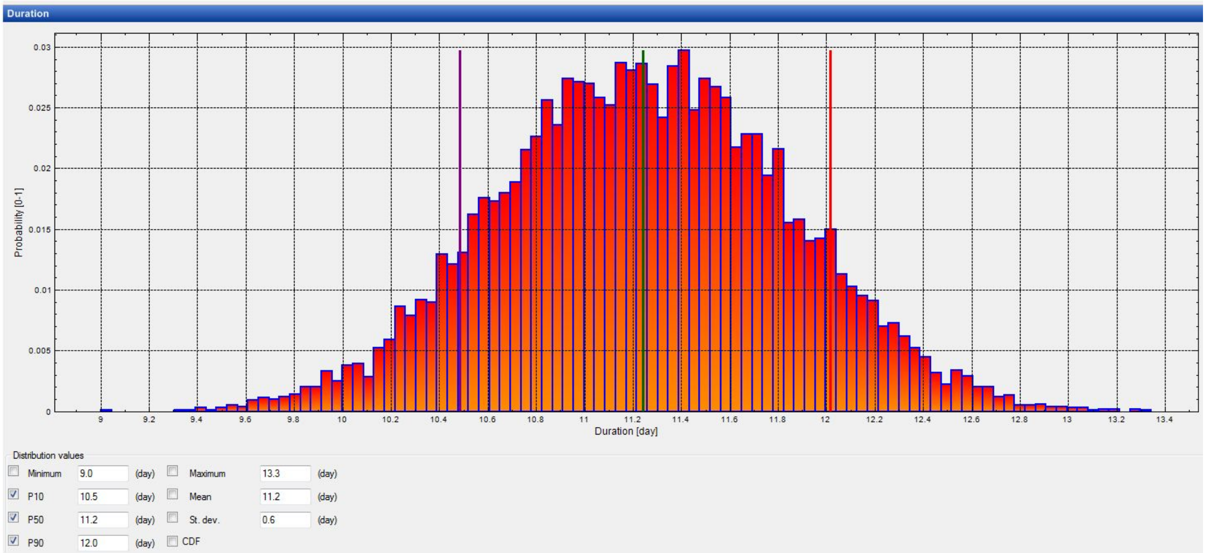


Case 1e Batch Histograms and Graphs

Case 1e Batch Cost Forecast Histogram

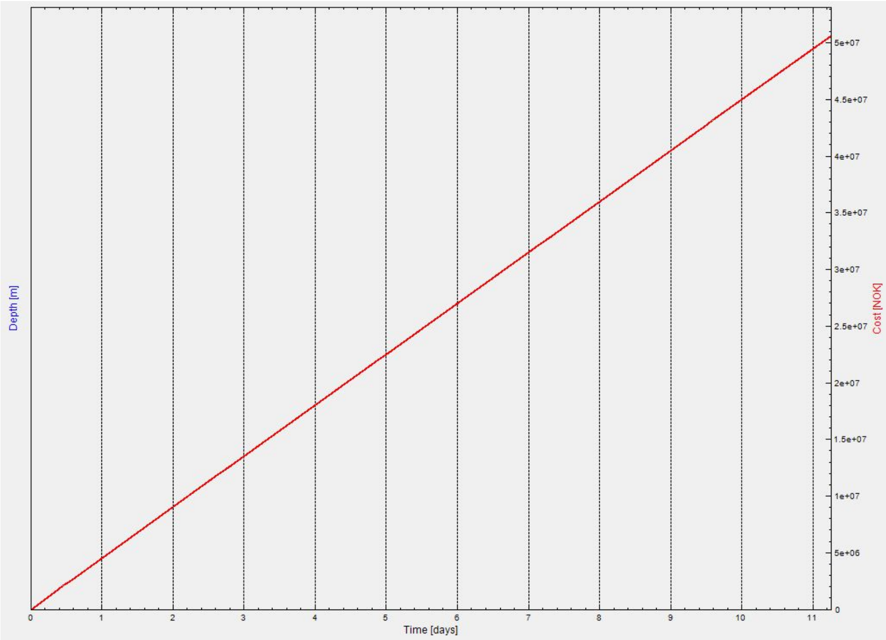


Case 1e Batch Duration Forecast Histogram



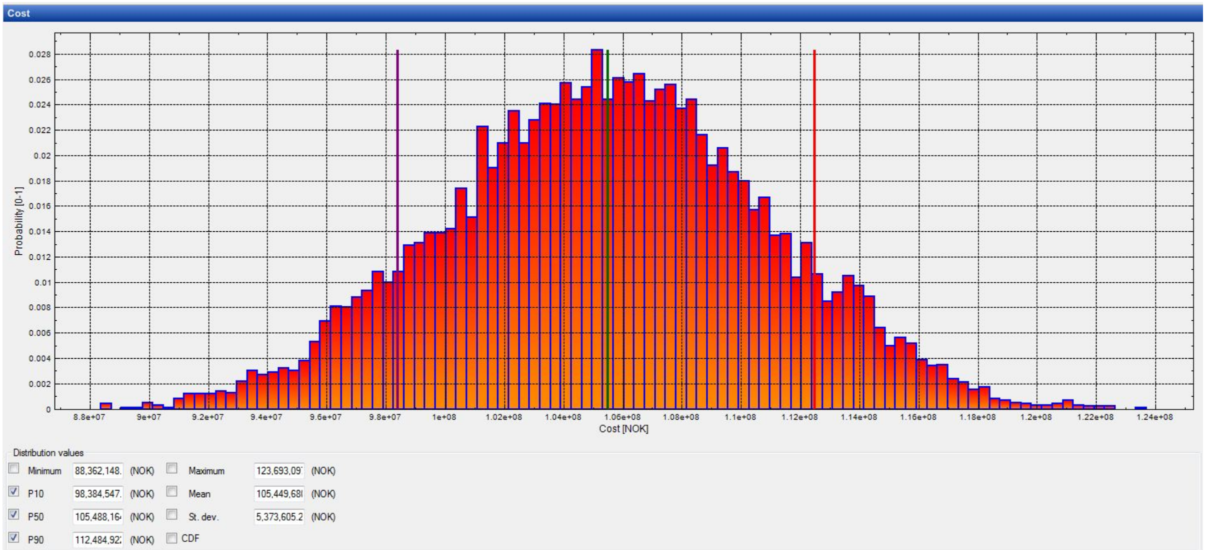
Case 1e Batch Phase Sensitivity Percentage

Case 1e Batch Time and Cost Graph

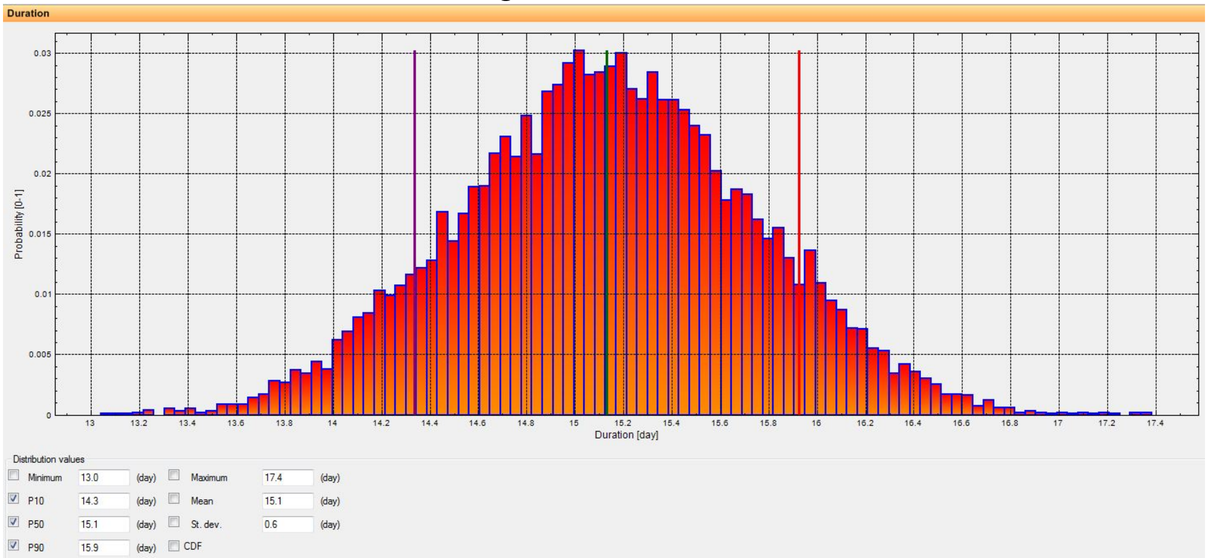


Case 2e Batch Histograms and Graphs

Case 2e Batch Cost Forecast Histogram



Case 2e Batch Duration Forecast Histogram



Case 2e Batch Phase Sensitivity Percentages

Case 2e Batch Time and Cost Graph