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Abstract

Due to high uncertainties and the cost intensive nature of well operations, accurate forecast of well cost and duration is one of the main requirements for writing an AFE and supporting decision making processes. Traditionally, the well cost has been estimated by the deterministic approach. However, this method has some limitations and the actual operating costs can significantly exceed the planned budget. Thus, the probabilistic approach of well cost estimation along with risk assessment has been developed and considered a more appropriate approach for dealing with well cost estimation.

There are many simulation tools which are available in the market. Nevertheless, the Risk€ software, developed by IRIS, is the simulation tool used here. This software also provides the function of including undesirable events into the simulation. Thus, risks associated with the well operations can be assessed effectively.

An example well model is created and the characteristics of the results are studied. Detailed analysis has been performed to observe how the changes in input parameters can affect the uncertainties and values of the simulated results. The case construction was inspired by a drilling program that was released from Statoil through the Academia program for teaching purpose.

The simulation showed that drilling and mobilization phases have the largest influence on the total well cost and duration. Besides, detailed sensitivity analysis revealed that better information of an expected range of ROP can greatly reduce the uncertainties of the results. When the expected values are analysed, the results demonstrate asymmetric behaviour. The effect on total duration and cost when the operation is slower is much greater than when it is faster.

Risk events are included in the simulation with an assumption that the problems can be solved and there is no extra cost associated with the events, only extra duration. Comparison between the standard operation plan and the risk operation plan also shows that unwanted events can drastically increase the uncertainties of the results and failure to include risk events in the forecast can lead to improper budget assigned to the project.

For future study, the software should be developed to handle more well operations scenario; such as multilateral well, lost in hole (LIH) situation, batch drilling including the effect of

learning curve and the completion phases. The software could also be extended for analysing new drilling technologies. Thus, well cost and duration estimation in various situations can be performed.

Acknowledgement

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My grateful thanks also go to IRIS, especially Øystein Arild, for providing me with the software to use in this thesis and Talisman Energy for offering the scholarship and summer internship during my master study in Norway.

I owe my deepest gratitude to my parents, Amphol and Pongthip, and my family for giving birth to me, providing me with the best educations and giving me support throughout my life.

Above all, I would like to dedicate this thesis to my aunt, Malai Kullawan, to whom I cannot find words to express my gratitude. I extremely thankful that she has always stood by me, believed in me, and given me unequivocal support and patience such that my mere expressions of thanks would not have been sufficient.

Last, but not least, special thanks go to all the professors and staffs in the department of petroleum engineering, University of Stavanger and my friends in Thailand, Norway and elsewhere for their help, support and encouragement in every way.

For any inadequacies and errors that may remain in this study, the responsibility is entirely my own.

Kanokwan Kullawan

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Nomenclature

AFE	-	Authorization For Expenditure
BHA	-	Bottom Hole Assemblies
BOP	-	Blow Out Preventer
CDF	-	Cumulative Distribution Function
HSE	-	Health, Safety and Environment
ID	-	Inner Diameter
LIH	-	Lost In Hole
LOT	-	Leak Off Test
LWD	-	Logging While Drilling
MCS	-	Monte Carlo Simulation
MD	-	Measured Depth
MU BHA	-	Make Up BHA
MWD	-	Measurement While Drilling
NOK	-	Norwegian Kroner
NPT	-	Non ProductiveTime
OAT	-	One At A Time
OD	-	Outer Diameter
OWC	-	Oil Water Contact
PDF	-	Probability Density Function
POOH	-	Pull Out Of Hole
RIH	-	Run In Hole
ROP	-	Rate Of Penetration
ROV	-	Remotely Operated Underwater Vehicle
RT	-	Rotary Table
SA	-	Sensitivity Analysis
SD	-	Standard Deviation
ST	-	Sidetrack
TD	-	Total Depth
TFT	-	Trouble-Free Time
UA	-	Uncertainty Analysis
USD	-	US Dollar
WOB	-	Weight On Bit
WOW	-	Wait On Weather

1. Introduction

1.1 Background

Among all petroleum exploration activities, drilling oil wells could be considered one of the riskiest and most expensive ventures. Record high oil price and shortage supply on drilling rigs, especially deep-water drilling rigs, have boosted the rig daily rental rate drastically over the past decade. Due to that reason, one of the objectives in drilling a hydrocarbon well is too make a hole in the ground as quickly as possible. However, there are 3 basic considerations which are required for successful drilling operations. First of all, the well needs to be drilled in a safe manner. Health, safety and environments, HSE, are always the top priorities although it may lead to delay in operation or extra cost. Second, the well must fulfil the requirements for its purpose either as an exploration, prospect appraisal or field development well. Regardless of the well type, there are minimum demands for all the wells. They should be drilled without damaging the borehole and the potential formations. They should also allow for formation testing, data gathering, hydrocarbon production, or other post-drill activity. The third basic consideration is that the overall well cost should be minimized. This topic has been the point of interest for the industry for a long time. Several oil companies have put a great effort in improving drilling efficiency and reducing drilling time in order to lessen the overall well cost.[8]

Previously, success of drilling project was defined by the completion of the well construction activities within the constraints of time, cost and performance. Nowadays, that definition has been modified. In 2002, Harold Kerzner pointed out the key issues for the drilling projects completion as shown below:[9]

- Within the allocated time period
- Within the budgeted cost
- At the proper performance or specification level
- Being accepted by the customer
- Without disturbing the main work flow of the organization

It is obvious that both cost and duration have always been considered as the key issues in drilling business. Thus, accurate forecast for drilling time and cost is necessary for drilling performance management.

1.2 Challenges Related to Well Cost Estimation

Although the companies are seeking for the correct estimate of well construction cost and duration, to achieve that may not be straightforward as it seems. Some of the major challenges related to well cost estimation are listed below:

- One main source of information for the model input is the historical data. Despite of that, there could be a shortcomings of the data acquired or the collected data may not have sufficient level of details. Furthermore, the available data may not be relevant to the wells being predicted.
- Well construction processes are associated with risks of undesirable events. These events, such as WOW, kick event, etc.; can cause delays in well operations. The total operation time is the summation of the trouble-free time (TFT) and the non-productive time (NPT). We may define TFT as the time required for planned operation and NPT is the time that any unplanned operations consume.[10]

  The challenge in writing AFE is that an extra duration caused by NPT could lead to a risk of exceeding a planned budget. Thus, accurate forecast for well cost is important so that appropriate budget is planned for drilling the well. There should be neither lacking of funding situation nor unspent funds left.[11]
- Besides the unwanted events, the planned operations are subjected to many uncertainties due to both geological and technical factors. The processes may take longer time than expected. This is where the probabilistic approach plays a significant role.

1.3 Study Objectives

The main objectives of this thesis are to discuss different approaches for well cost estimation as well as their advantages and limitations along with their development over time and to combine major drilling risks into cost estimation. Besides, this study also aims at studying the characteristics of the forecasted results and providing recommendations for the software future development.

1.4 Structure of the Thesis

This thesis is divided into 7 chapters. The first chapter is the introduction part of this thesis which covers the background of this study, what have made this topic challenging, the objectives of this thesis and the structure of the thesis. In the second chapter, literature reviews regarding well cost estimation have been performed. This chapter presents various methods of performing well cost estimation, the software which is available in the market, its development overtime and some statistical refresher. Chapter 3 discusses about the Monte Carlo simulation and shows a calculation example using this technique. After that, some major risk events which are associated with the drilling operations are explained in chapter 4. Then, chapter 5 describes the Risk€ software which is the simulation tool used in this study. Next, in chapter 6, the simulation of an example well has been conducted and the results are discussed. Finally, the last chapter offers the conclusion of this study and the recommendations for future study and the software development.

2. Well Cost Estimation

2.1 AFE Writing Procedures

"AFE (Authorization for Expenditure) is a budgetary document, usually prepared by the operator, to list estimated expenses of drilling a well to a specified depth, casing point or geological objective, and then either completing or abandoning the well. Such expenses may include excavation and surface site preparation, the daily rental rate of a drilling rig, costs of fuel, drillpipe, bits, casing, cement and logging, and coring and testing of the well, among others. This estimate of expenses is provided to partners for approval prior to commencement of drilling or subsequent operations. Failure to approve an authority for expenditure (AFE) may result in delay or cancellation of the proposed drilling project or subsequent operation. In short, it is the cost of drilling and constructing a well."[12]

Generally, estimation of the well construction cost has been based on historical data. Major operators collect a variety of data related to drilling operations, such as: [13],[14]

- Time and cost information for various operations
- Drilling problems, time and cost associated with the problems, and their solutions
- Comparisons of drilling performance

Drilling engineers combine the offset wells data, engineering calculations, projections about operational improvements and plan for contingency cost in order to write the AFE. These data will be analysed for an estimation of drilling performance and the likelihood of facing drilling problems. Expert judgments could also be added.

Due to extremely high cost of the daily rental rate of drilling rigs, the time taken to drill a well could represent 70 to 80% of the final well cost. Since the duration of the well construction has a significant impact on the budget planning, it becomes a common practice to assess the well duration together with the well cost. There are two main approaches which are commonly used for well cost estimation. These are the deterministic and the probabilistic approach. More details about each method are described below.

2.2 Deterministic Well Cost Estimation

Traditionally, the well cost estimates have been developed by a deterministic approach. The budget for the well construction cost has been based on a single value, a base-case cost. In order to take uncertainties and risks into account, the optimistic case and the pessimistic case could also be developed by adding or subtracting a certain percentage from the base-case cost. The optimistic and pessimistic cases are sometimes mentioned as low and high cost estimates. [7],[15]

2.2.1 Advantages of the Deterministic Approach

- The deterministic approach is simple.
- It has a clear set of assumptions.
- The method gives quick results which are easy to communicate.

2.2.2 Limitations of the Deterministic Approach

- From historical well cost estimates, the deterministic approach has been too optimistic. The prediction may be subjected to technical imperfection such as systematic underestimation.[16]
- It does not reflect the full range of possible outcomes.
- The likelihood of any particular outcomes and the probability that the actual well cost will be the same or close to the predicted value are not quantified.

The figure below shows the results from a deterministic estimation of the well cost and duration. The blue line is a time – depth curve which represents the relationship between the progress of the well depth and the time spent on the processes. The red line is a time – cost curve which illustrates the how the costs increase as the well operations are going on.

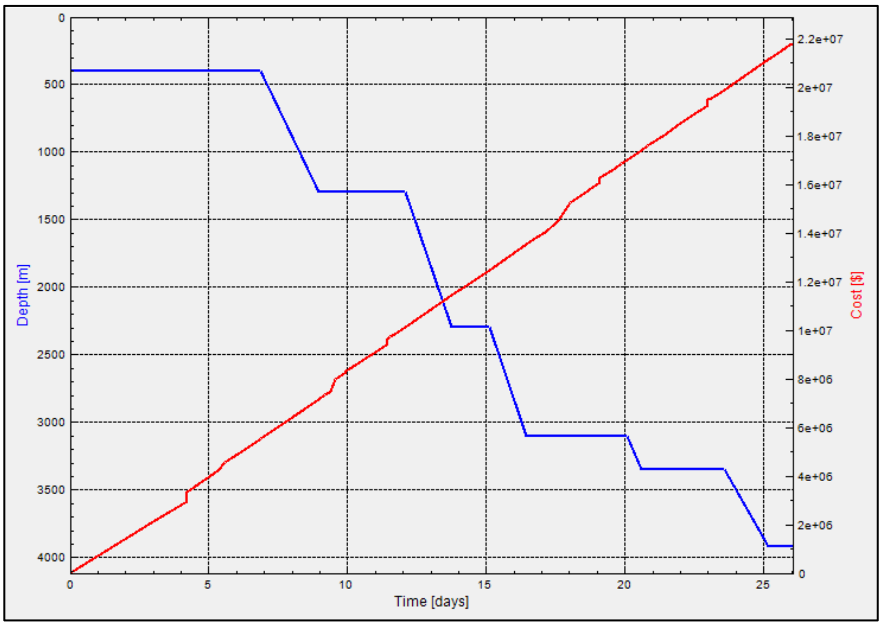


Figure 1: Time – Depth Curve and Time - Cost Curve given by a deterministic cost and time estimation (Figure taken from Risk€ Software)

2.3 Probabilistic Well Cost Estimation

By the nature of oil & gas upstream operations, there are a lot of risks and uncertainties associated with the activities. With the limitations of the deterministic method mentioned before, the probabilistic method, also referred to as the stochastic method, is considered a more suitable approach for dealing with uncertainties in time and cost management. This method has quickly become a common business practice in the well construction industry.[17] This concept also utilizes historical data from offset wells, but in the form of probability distributions. Probabilistic technique provides many advantages for both users and decision makers for maximizing correct decision making and preventing time and cost overrun.

The main concept of the probabilistic well construction time and cost estimation is to apply the Monte Carlo simulation technique in combination with the use of probability distributions for cost and duration estimation.

In addition, the probabilistic approach can include unwanted events into the well model, which cannot be done by the deterministic approach. As a result, risk assessment can be conducted more efficiently.

2.3.1 Advantages of the Probabilistic Approach

As the probabilistic approach is referred to as the more appropriate method for well cost estimation, some of its advantages are listed below. [7],[17]

- In probabilistic estimating, the stakeholders are better acknowledged with the uncertainties in well construction operation and the range of expected outcome.
- Risks and opportunities can be addressed earlier in the planning processes and the awareness of risks, opportunities and their impact is significantly improved.
- It helps the decision makers to make better decisions by using consistent methodology in decision making process.
- The offset data is analysed thoroughly which leads to better transfer in experiences and best practices among the project teams.
- This method allows for sensitivity analysis. Thus, more effective allocation of funding and resources can be focused on the key cost drivers.
- In the probabilistic approach, the well construction is broken down into consecutive steps and the offset data is analysed along with the well model. This can clarify

opportunities and risks in performance. Thus, it supports the performance improvement as well as pointing out the limitations of the technical process.

- If there are several alternatives for the well construction process, comparison of the alternatives can be provided.
- It helps in cost-benefit evaluation of risk reducing measures. Planned well construction is compared to an adjusted operation plan. The benefits of the adjusted plan can be examined and balanced with the cost that needs to be spent on it.
- It also promotes accurate recording and reporting of actual operation time and cost data, which is important for performance management and improvement. Realizing that the database is utilized significantly, the data collectors will have better understanding about the necessity of good data quality.
- It can identify the probability of finishing the well construction within a given time window. This issue could be critical in some areas, e.g. in the Barents Sea, where the drilling time window is tight. This is due to the fact that, in the Barents Sea, drilling is only performed during the winter season for sea life protection.

2.3.2 Limitations of the Probabilistic Approach

Although the probabilistic approach brings many benefits and advantages which lead to improvement in the planning and decision making process, the probabilistic assessment has its limitations just as the deterministic approach. [17]

- The probabilistic approach should never be expected to identify and capture all risks and uncertainties. There will always be unknown unknowns.
- The results from the analysis should always be accompanied with the philosophy used in model construction. The users of the prediction results should understand the assumptions used in the model.

2.4 Software Available in the Market

While performing probabilistic well cost estimation and/or Monte Carlo simulation, a number of software can be used as a tool. Software selection varies with users and organizations. Some companies have developed their own software or spreadsheet for drilling cost forecasting purpose. Some organizations utilize available commercial software for their prediction. Frequently, the commercial software used in cost estimation activity is a spreadsheet-based application which allows users to perform Monte Carlo simulation from their existing spreadsheet software. Major oil field service companies also offer well cost estimation and risk analysis software as one of their services. In this case, the software providers generally offer other services and/or software which have the potential to enhance the efficiency of cost estimation.

Beside Risk€[18] software which will be used in this thesis, examples of the software available in the market will be described here.

2.4.1 Commercial Software

- **@Risk from Palisade Corporation**[19]: @Risk is an add-in to Microsoft Excel. This software performs risk analysis using Monte Carlo simulation. The range of possible outcomes and the likelihood that each result will occur are shown in Microsoft Excel spreadsheet. This can help decision makers to make decisions under uncertainties. The software has been used in various industries, from the financial to the scientific. In oil and gas industry, its application is including, but not limited to, exploration and production, oil reserves estimation, capital project estimation, pricing, and regulation compliance.

  When setting up the model, the user can select the probability distribution or define the distribution from the historical data for a given input. The results from the simulation are the whole range of possible outcomes with the probabilities they will occur. It also offers the tornado chart and sensitivity analysis to identify the critical factors.
- **CrystalBall from Oracle**: CrystalBall is a spreadsheet-based application which is suitable for predictive modelling, forecasting, simulation and optimization. Similar to @Risk, both of them are generic Monte Carlo software. It uses Monte Carlo

simulation to calculate and record the results of thousands of different scenarios. Analysis of these cases reveals the range of possible outcome, their probability to occur, the input that most impact the model and the key point that should be focused on. [20]

2.4.2 Company Developed Software

- **Spreadsheet developed by Conoco Inc.**: It is a drilling-cost spreadsheet developed by Conoco drilling engineers. It combines forecasting and risk analysis to predict the range of cost and duration required to drill a well. More detail about this software is given in chapter 2.5. [15]
- **Drilling and Well Estimator (DWE) by Statoil**: Statoil has developed a cost estimation software to use with its drilling and well operation worldwide. The software uses the statistical method from the company's large data base. When there is a lack of data, risk management method is utilized. More detail about this software is given in chapter 2.5.[21]

2.4.3 Software Product from Service Companies

- **WellCost software from Halliburton**: Halliburton offers the Wellcost software using both the deterministic and probabilistic method for drilling cost estimation. It helps drilling and completion engineers generate cost estimate for the operations throughout the life of the well. The software works together with other related software and services provided by Halliburton. [22]
- **Osprey Risk software from Schlumberger**: Osprey Risk is a plug in for Petrel drilling software. It enables drilling engineers to find the balance of risk, efficiency and cost. It analyses the risks and their subsequent effects on cost and time. [23]
- **P1 and C1 from the Peak Group**: The P1 software from the Peak Group was used to generate cost and duration estimation for each operational phase e.g. drilling top hole section, etc. However, in order to generate the estimation for the whole field, a new system was required. Thus, C1 was developed to use the output probability curves from P1 to generate a probabilistic time and cost estimation for the whole development campaign. [24]

2.5 Development of Probabilistic Approach and Monte Carlo Simulation in Well Cost Estimation

The first use of Monte Carlo Simulation techniques and the probabilistic approach in the petroleum industry was seen several decades ago. In 1976, there was a paper by Capen[25] which was one of the earliest SPE publications that was associated with the probabilistic method. After that, the technique became more popular in the reservoir engineering discipline and here it has been used routinely. However, it took longer time for this technique to become a common practice within the drilling engineering discipline.

In 1993, Peterson et al. from Marathon Oil Company[13] published a paper which considered applying Monte Carlo Simulation for the generation of the drilling AFE. At that time, collecting data related to drilling operations in databases had just been standard practice for only few years. Thus, there were questions regarding the availability of accurate historical data and the shortcomings of the data acquired.

In 1997, Probabilistic Drilling-Cost Estimating publication by Kitchel et al from Conoco Inc.[15] discussed how the company applied the technique to perform an estimation of the drilling cost. Since risk analysis had become a significant part in the decision-making process in the petroleum industry, Conoco drilling engineers built a drilling cost forecasting spreadsheet with a model that combined risk analysis and Monte Carlo simulation along with regional cost data. The spreadsheet provided a query sort for the major feature categories and divided them into 2 groups. The first group was called the big-rock sort. The features that fell into this group were the key cost drivers that accounted for 80% of the total cost estimate. There were relatively few features that fell into this category and those features were dealt with the probabilistic approach. Additional efforts were put in describing the uncertainty for these features. The other group was the small rocks which would be simply dealt with the deterministic approach by entering single values into the spreadsheet.

In 2003, a publication by Zoller from Enterprise Oil do Brasil Ltda and Graulier and Paterson from the Peak Group[24] presented the next step in applying the Monte Carlo simulation technique in well construction cost estimation. Commercial Monte Carlo simulation software was used in this study, such as, @Risk and CrystalBall. Before this, probabilistic time and cost estimation was generated for each of the operational phases. The benefits of single operation modeling were quickly appreciated and this led to a wish to extend the model for multiple wells for the whole field development campaign. However, this could not be achieved by a simple addition of the individual well models. It required another level of Monte Carlo simulation by using individual well distribution as an input. First of all, the model for the individual well was built in order to understand the uncertainty of the well construction process. Then, this model was split into 7 batch phases which are top hole, 12 ¼” pilot hole, sidetrack 12 ¼” main bore, 8 ½” hole, well test, run upper completion and run subsea Christmas tree. The simulation results from each operation phase of the campaign are the statistical distributions which will be used in the MCS as an input to generate the whole field simulations for duration and cost. Learning effect and correlation of similar activities were mentioned in this study; however, more research was required in order to apply this using the probabilistic approach.

In 2006, Hariharan and Judge from SPE and Nguyen from Hydril Co.[14] published a paper considering the application of the probabilistic analysis while evaluating the benefits of new technologies. For emerging technologies, most of the time, the historical data was not available. In those cases, the probabilistic approach was, perhaps, the best and most suitable way of analyzing the impact and benefit of the technologies. Even though the use of the probabilistic approach and Monte Carlo simulations had been introduced for well cost estimation for a long time, it was pointed out in this paper that there still had been limited published work involving this topic. The survey was conducted and its results presented that one of the main obstacles in the prevalence of probabilistic methods was the lack of regular training and refresher courses to relevant personnel.

In 2008, Løberg and Arild from IRIS, Merlo from Eni E&P and D’Alesio from ProEnergy[7] introduced Risk€ software as a tool to introduce and strengthen the application of probabilistic well cost estimation. The model used in this software divides the well construction processes into several sub-operations. The total cost and duration consist of the summation of the cost and duration of all the sub-operations. With this model, alternative well designs can be compared in terms of cost uncertainties. Undesirable events were included in the well construction process with given probability of occurrence and the potential extra duration caused by the event. Then, the results were presented in 2 ways, i.e. both for the standard operation plan without undesirable events and risk operation plan when the undesirable events are included.

In 2010, Hollund et al[21] discussed about developing a spreadsheet model regarding the probabilistic model for estimating drilling time and cost in Statoil. The model which was described in this paper applied a statistical methodology from a large database along with an integration of estimation and risk management when lacking available data. The well model was broken down into the number of drilling activities. After that, the model was calibrated to the historical data based on geography, geology, technology and the time period. Then, an outlier algorithm was implemented to validate the data. The development resulted in the software application named Drilling and Well Estimator (DWE) which was linked directly into the company's database. This software will be used for time and cost estimation of all Statoil drilling and well operation to enhance unbiased estimates. It resulted in an improving trend of delivered wells being closer to estimations in the planned wells.

In 2011, Jablonowski et al[26] presented that the use of learning curve for cost estimating has become a best practice among many operators. For drilling and completion campaign with several wells, performance related to cost and duration tended to improve. Thus, ignoring the effect of the learning curve could lead to a forecast which is too pessimistic. They also proposed the 3-step procedure of applying the learning curve in probabilistic cost estimation. First, normal probabilistic analysis is performed. In this step, the learning effect would not be considered. In the second step, the learning effect would be applied in either a deterministic or a probabilistic manner. This could be done by applying an equation from Brett and Millheim.[27] The deterministic learning is appropriate when there is small uncertainty in an estimate of the learning equation's parameters. If the uncertainty in one or more parameter is large, the probabilistic learning is more suitable. Then, in the last step, adjust the result after the simulation. The original probabilistic estimate achieved in the first step should be updated as the wells are executed.

2.6 Statistics Refresher

In this section, definitions and equations of some basic statistical values will be described in order to prompt the readers for more details on the probabilistic estimation in the following chapters. [28]

- **Percentile:** The set of divisions that produce exactly 100 equal parts in a series of continuous values. It is the lowest value which is greater than a certain percent of the observations. 10th percentile, or P10, is the smallest value that is greater than 10 percent of the observations.
- **Arithmetic Mean:** A measure of location or central value for a continuous variable. For a sample of observations x_1; x_2; . . . ; x_n the measure is calculated as

$$\bar{x} = \frac{\sum_{i=1}^{n} x_i}{n} \tag{1}$$

  The arithmetic mean is most useful when the data have a symmetric distribution and do not contain outliers.

- **Standard Deviation:** The most commonly used measure of the spread of a set of observations. It is a measure of the dispersion of a set of data from its mean. The more spread apart the data, the higher the deviation will be. Standard deviation is equal to the square root of variance. The square root of the sample variance of a set of N values is the standard deviation of a sample which can be calculated by:

$$S_N = \sqrt{\frac{1}{N} \sum_{i=1}^{N} (x_i - \bar{x})^2} \tag{2}$$

  However, this estimator is a biased estimator when applied to a small or moderately sized sample. It tends to be too low. The most common estimator for the standard deviation is an adjusted version which is defined as:

$$S_{N-1} = \sqrt{\frac{1}{N-1} \sum_{i=1}^{N} (x_i - \bar{x})^2} \tag{3}$$

- **Median:** Median is a value in a set of ranked data which divides that data set into 2 groups of identical size. If there is an odd number of data points, the median is the value in the middle. If there is an even number of data points, the median can be calculated from the average of the 2 values in the middle.

2.7 Probability Distribution

Probability distribution is a graphical or mathematical representation of the range and likelihoods of possible values that a random variable, a variable that can have more than one possible value, can have. The probability distribution can be either discrete or continuous. This depends on the nature of each variable. For a discrete random variable, a mathematical formula gives the probability to each value of the variable, such as binomial distribution and Poisson distribution. For a continuous random variable, a curve described by a mathematical formula specifies the probability that the variable falls within a particular interval, by way of areas under the curve. Probability is a personal appraisal of uncertainties. Thus, there is no predefined probability distribution for any particular uncertain situations. Most risk analysis and statistical software offers a wide variety of distributions. However, there are several distributions that show up frequently in petroleum exploration risk analysis, their definitions and characteristics will be briefly discussed here. Proper references for the theory presented in this section is given in [28],[29],[6].

2.7.1 Uniform Distribution

The uniform distribution is a continuous probability distribution, f(x) of a random variable which has constant probability over an interval. It is sometimes mentioned as “rectangle” or “boxcar” distribution, or a random distribution. This distribution is defined by two key parameters, a and b, which are its minimum and maximum values respectively.

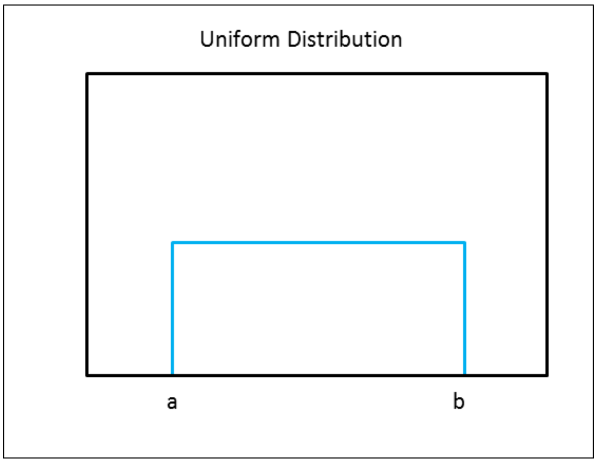


Figure 2: Uniform distribution plot.

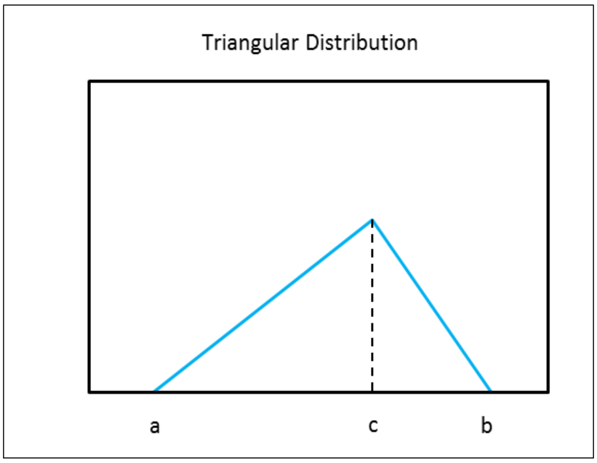
$$\textit{Probability Distribution Function};\ f(x) = \begin{cases} \frac{1}{b-a}, & a \le x \le b \\ 0, & x < a \text{ or } x > b \end{cases} \qquad (4)$$

$$\textit{Mean};\ \mu = \frac{a+b}{2} \qquad (5)$$

$$SD;\ \sigma = \sqrt{\frac{(a-b)^2}{12}} \qquad (6)$$

2.7.2 Triangular Distribution

Triangular distribution is a continuous probability distribution with the minimum value at a, maximum value at b and its peak value at c, sometimes defined as lower limit, upper limit and mode respectively. It can be symmetrical or skewed in either direction. It is typically used when there is limit sample data available, especially in cases where the relationship between variables is known but data is limited.



Triangle (a, b, c)

Minimum, a

Most Likely, c

Maximum, b

Figure 3: Triangle distribution plot.

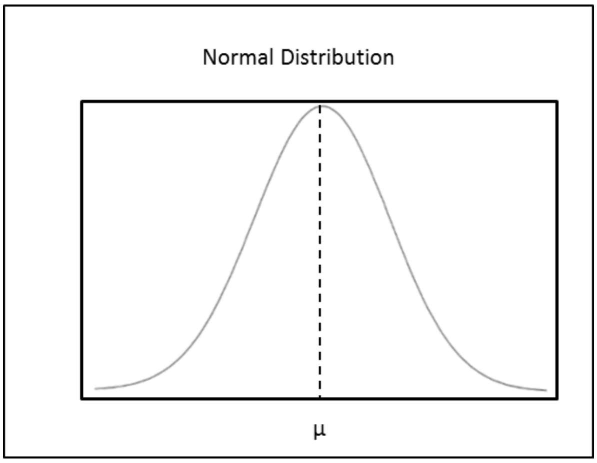
$$\textbf{Probability Density Function};\quad f(x|a,b,c)=\begin{cases}0 & , \; x<a \text{ or } x>b\\ \frac{2(x-a)}{(b-a)(c-a)}, & a\le x\le c\\ \frac{2(b-x)}{(b-a)(b-c)}, & c<x\le b\end{cases} \qquad (7)$$

$$\textbf{Mean};\; \mu=\frac{a+b+c}{3} \qquad (8)$$

$$\text{SD};\; \sigma=\sqrt{\frac{(b-a)(b^2-ab+a^2)-cb(b-c)-ac(c-a)}{18(b-a)}} \qquad (9)$$

2.7.3 Normal Distribution

The normal distribution, or sometimes known as the Gaussian distribution, is the most widely known and used of all the distributions. Since the normal distribution is a good representative for many natural phenomena, it has become a standard of reference for many probability problems. This distribution is symmetric and bell shaped. All values of *X* between -∞ and ∞ are continuous. The mode (most likely value), median (value of the random variable that separate the distribution into two equal parts), and the mean are all equal. The mean, μ, and variance, σ^2, determine the shape of the distribution. Thus, the normal distribution is actually a family of distributions.



Normal (μ, σ)

Mean, μ

SD, σ

Figure 4: Normal distribution plot.

$$\textbf{Probability Density Function};\quad f(x)=\frac{1}{\sigma\sqrt{2\pi}}exp\left[-\frac{1}{2}\frac{(x-\mu)^2}{\sigma^2}\right] \qquad (10)$$

$$\textbf{Mean};\; \mu = as\ specified \qquad (11)$$

$$\textbf{SD};\; \sigma = as\ specified \qquad (12)$$

2.7.4 Lognormal Distribution

Lognormal distribution is a continuous distribution where the logarithm of the variables has a normal distribution. It is similar to the normal distribution but its shape is asymmetric. It is skewed to one side. If X is a random variable with a normal distribution, then $Y = \exp(X)$ has a log-normal distribution; likewise, if Y is log-normally distributed, then $X = \log(Y)$ is normally distributed. This is true regardless of the base of the logarithmic function: if $\log_a(Y)$ is normally distributed, then so is $\log_b(Y)$, for any two positive numbers $a, b \neq 1$. It is occasionally referred as the Galton Distribution.

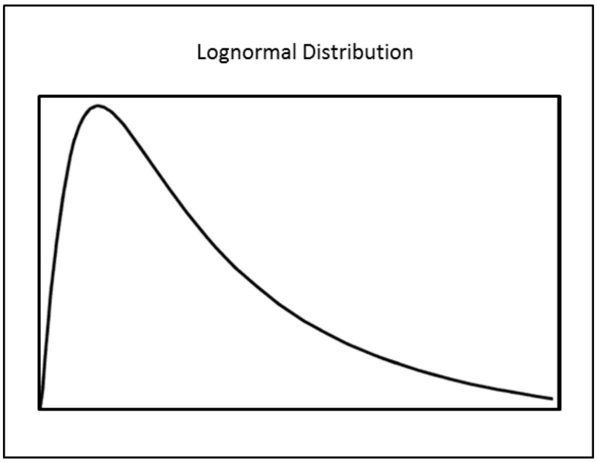


Figure 5: Lognormal distribution shape.

$$\boldsymbol{Probabilidy\ Density\ Function};\ \mathbf{f(x)} = \frac{1}{x\sigma(2\pi)^{1/2}} \exp\left[-\frac{1}{2\sigma^2}(\ln x - \mu)^2\right], 0 \leq x < \infty \quad (13)$$

$$\boldsymbol{Mean};\ \boldsymbol{\mu = as\ specified} \quad (14)$$

$$\boldsymbol{SD};\ \boldsymbol{\sigma = as\ specified} \quad (15)$$

2.7.5 Weibull Distribution

Weibull Distribution is a continuous probability distribution. It is named after Waloddi Weibull, the Swedish physicist. The distribution occurs in the analysis of survival data and has the important property that the corresponding hazard function can be made to increase with time, decrease with time, or remain constant, by a suitable choice of parameter values. This distribution is appropriate when the failure probability varies over time. Thus, it is often used in reliability testing, weather forecasting, etc. The probability distribution, f(x), is given by:

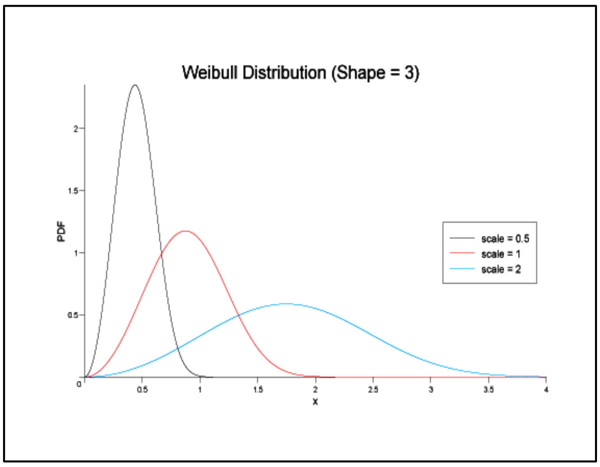


Figure 7: Weibull Distribution with shape parameter = 3 – Source: [4]

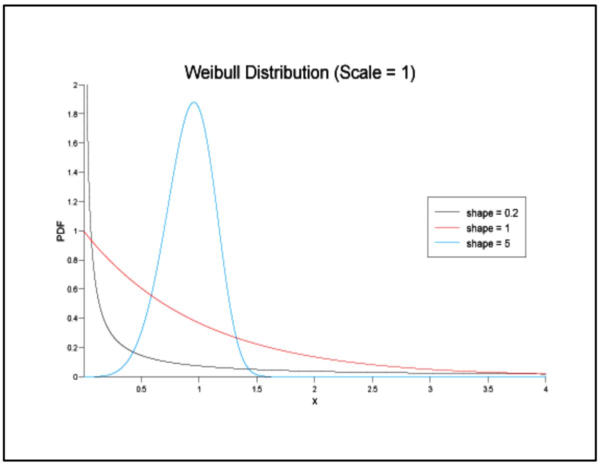


Figure 6: Weibull Distribution with scale parameter = 1 - Source: [4]

$$\boldsymbol{Probability\ Density\ Function;}\ \ f(x) = \begin{cases} 0 & ,\ x < 0 \\ \dfrac{\gamma x^{\gamma-1}}{\beta^{\gamma}} exp\left[-\left(\dfrac{x}{\beta}\right)^{\gamma}\right] & ,\ x \geq 0 \end{cases} \qquad (16)$$

$$\boldsymbol{Mean;}\ \mu = \beta\Gamma\left(1 + \frac{1}{\gamma}\right) \qquad (17)$$

$$\boldsymbol{SD;}\ \sigma = \beta\sqrt{\Gamma\left(1 + \frac{2}{\gamma}\right) - \Gamma\left(1 + \frac{1}{\gamma}\right)^{2}} \qquad (18)$$

where $\gamma > 0$ is the shape parameter and $\beta > 0$ is the scale parameter of the distribution. When $\gamma = 1$, Weibull distribution becomes the exponential distribution.

2.7.6 Discrete Distribution

A discrete distribution is a statistical distribution whose variables can take only discrete values. It can be binomial distribution, only two outcomes are possible on any given trial, and multinomial distribution, any number outcomes are possible. The mean and standard deviation of this distribution is given by:

$$\boldsymbol{Mean;}\ \mu = np_i \qquad (19)$$

$$\boldsymbol{SD;}\ \sigma = \sqrt{np_i(1 - p_i)} \qquad (20)$$

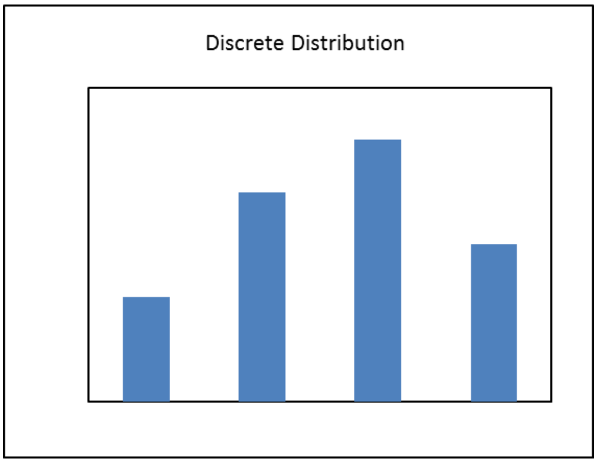


Figure 8: Discrete Distribution plot.

Where n is the number of independent trials and p_i is the chance of success.

2.7.7 Examples of Variables Represented by Each Type of Probability Distribution

Type of Probability Distribution	Example of Variables Represented by Probability Distribution
Uniform	used in exploration risk analysis with MCS method, platform operating cost
Triangle	used in exploration risk analysis with MCS method, drilling cost, short duration NPT
Normal	core porosity, percentages of abundant minerals in rocks, percentages of certain chemical elements or oxides in rocks
Lognormal	core permeability, thicknesses of sedimentary beds, oil recovery, short duration NPT, welltime, depth, problem free time, repair time
Weibull	weather forecasting (WOW time), long duration NPT

Table 1: Examples of variables represented by each type of probability distribution – Source: [29],[10]

3. Monte Carlo Simulation

Monte Carlo simulation (MCS) is a statistic-based analysis methodology which is very popular among engineers, geoscientists, and other professionals for evaluating prospects or analysing problems that involve uncertainty. The methodology gives probability and value relationship for key parameters, including oil and gas reserves, capital exposure and economic values, such as net present value (NPV) and return on investment (ROI).[6],[13],[30]

A Monte Carlo simulation is a model that consists of one or more equations. The variables of the equations are separated into inputs and outputs. Some or all of the inputs are treated as probability distributions rather than deterministic numbers. The user selects the type of statistical distribution for each input parameters. This process is guided by the user's experience and fundamental principles, but driven by use of historical data. In Monte Carlo simulation, it is assumed that the variables are independent. In case that two or more variables are dependent on one another, dependency is required to be included in the model. The results of the simulation are also given as distributions which describe the minimum, maximum and most likely values, including means, standard deviation, the10th percentile, the 90th percentile, etc. The simulation is a succession of hundreds or thousands of repeating trials. Each trial randomly selects one value from each input parameter and calculates the outputs. During each trial, the output values are stored. After that, the output values for each output are grouped into a histogram or a cumulative distribution function.

3.1 Procedure of Monte Carlo Simulation

Processes of the Monte Carlo simulation technique can be divided into 5 steps. [17],[6],[31]

3.1.1 Define an Appropriate Model

To perform the MCS, the objectives and scope of the model need to be properly defined. These can vary tremendously, depending on the stage of the project. For example, the initial estimate will require different level of details from the AFE level estimate. Generally, the model gets more details as the planning process moves towards execution. However, it should be noted that a more detailed model does not necessarily mean a more accurate one.

To be able to include risk events in the model is one of the advantages of utilizing the probabilistic approach in well cost estimation. Risks, opportunities, contingencies or scope changes should be included in the model. There are no concrete rules which dictate what are needed to be in the model. This can depend on the company policy, standard practice, economic evaluation, etc. Nevertheless, a consistent approach is important when dealing with major risk events, wait on weather or other environmental interruptions, opportunities and scope changes.

3.1.2 Data Gathering

Based on an assumption that exact values of model inputs are not known, data gathering is essential to help quantifying the uncertainty. In order to represent a full range of possible performance and outcome, the set of data collected should be large enough. This will also reduce the effect of small sample size. Besides, the data should only be taken from offset wells which are comparable to the well to be forecasted.

3.1.3 Select Suitable Probability Distribution for Input Variables

There are several probability distributions which are commonly used in the exploration activities to fit the offset data for input parameters. There are 2 main steps in defining input distributions. The first step is to choose the distribution shape, such as uniform, triangle, log-normal, etc. The second step is to define the distribution parameters, e.g. minimum value, standard deviation, P90th percentile etc.

Triangular and uniform distributions have become popular for well cost and duration estimation. Although these distributions are simple, the simplicity does not imply imprecision. However, it is more important to ensure that the input distributions adequately reflect the mean and spread of the offset data than to decide which distribution is the most suitable.[17]

3.1.4 Randomly Sample Input Distributions

Historically, the Monte Carlo method was considered to be a technique, using random or pseudorandom numbers, for solution of a model. Random numbers are essentially independent random variables uniformly distributed over the unit interval [0, 1]. First of all, the probability density function (PDF) is transformed to its cumulative distribution function (CDF) equivalent. Secondly, a uniformly distributed random number is selected between 0 and 1. The selected random number is used to enter the vertical axis of the CDF curve and then down to the horizontal axis. By taking the inverse of the CDF function, a unique value of the corresponding parameter is obtained. The random numbers are having a uniform distribution between 0 and 1so they are equally likely. Thus, the resulting samples are also equally likely. However, it is not necessary that the distribution of the resulting sample values is a uniform distribution. This is due to the fact that although each sample value is equally likely, more samples are generated from the steepest part of the CDF curve. The process of generating the random number for each input parameter is represented by the figure shown below.

Please be noted that it is incorrect to apply the same random number to sample all the input distributions. If a single value of random number is used for all distribution, it would automatically imply fixed value for all variables. For instance, if the selected random number is low and it is applied to all inputs, combination of high and low value of each variable is not possible. Thus, it is the rule that we use a separate random number to sample each distribution.[29]

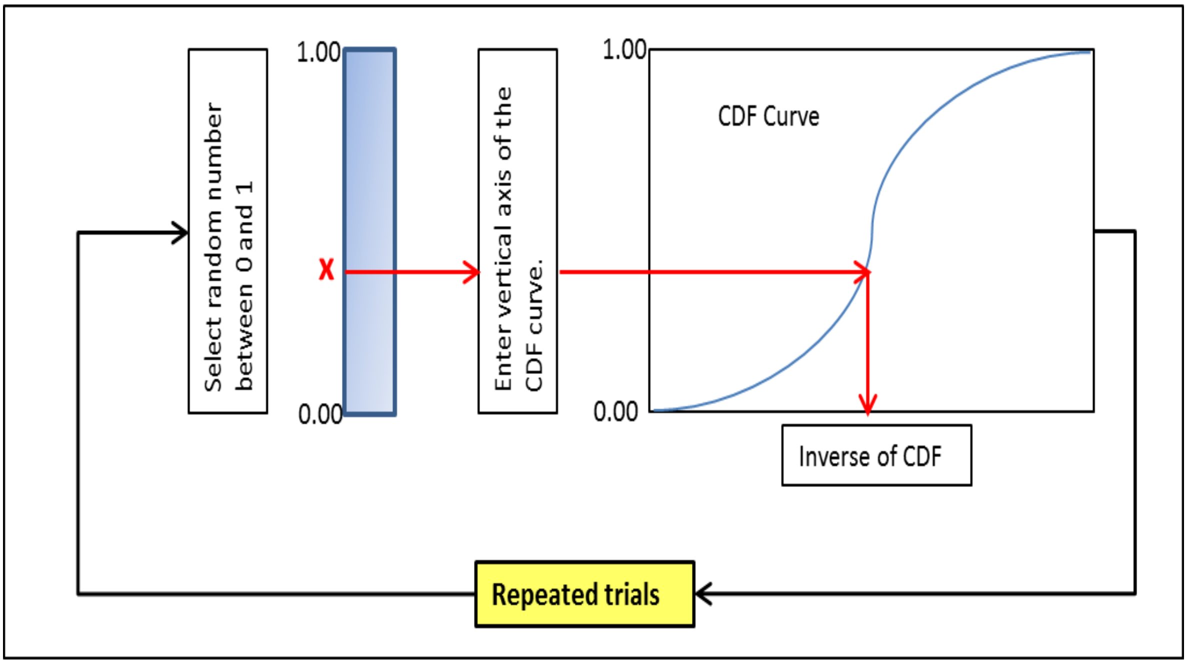


Figure 9: Schematic of input parameter generation. – Source: [6]

3.1.5 Compute the Model Results and Generate Statistics of Results

The inverse of the CDF curve on the horizontal axis is the input value which will be used to compute the model results. The result of each trial will be stored. This process is repeated as many times as needed. Then the stored results will be used to build the histogram of the output variables. The schematic of the Monte Carlo simulation procedure is shown below.

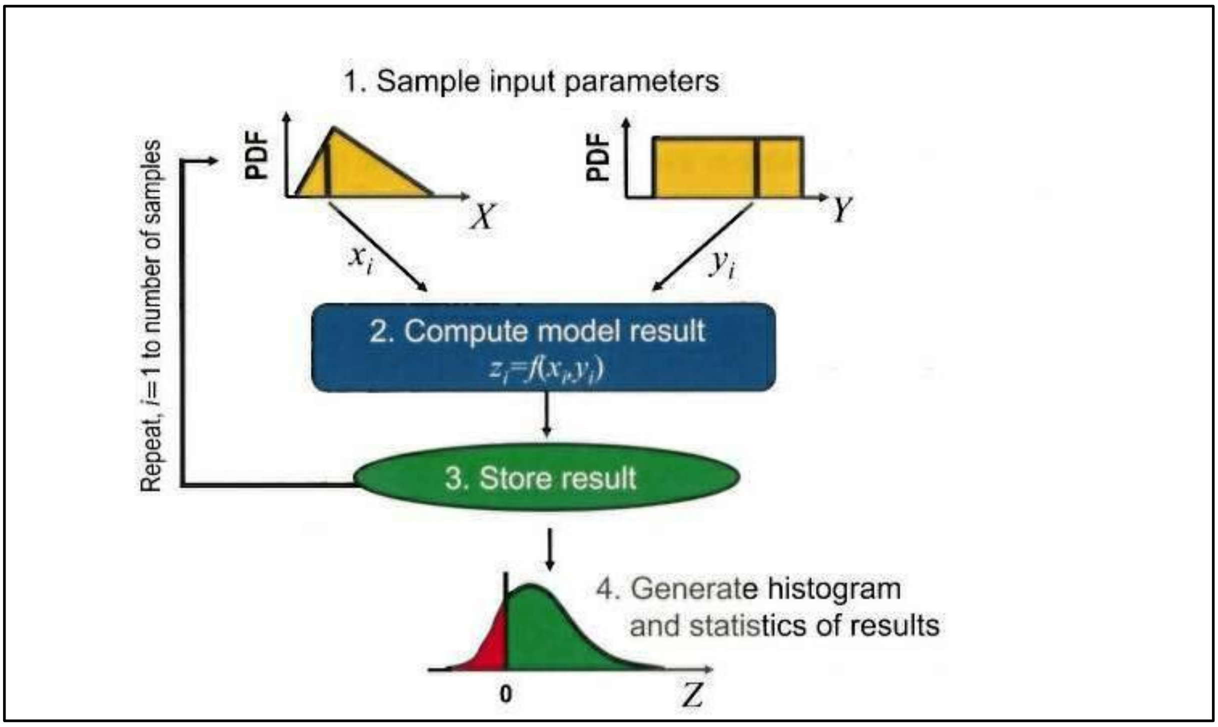


Figure 10: Schematic of Monte Carlo simulation procedure – Source:[6]

3.2 Advantages of Monte Carlo Simulation

The Monte Carlo simulation offers a number of advantages as follows: [6]

- We have mentioned before that we may not know the exact values of input parameters. With the MCS technique, the input variable distributions do not require any approximation.

- It is easy to model the correlations and dependencies, based on the assumptions that they are recognized and well understood.

- Typical petroleum engineers and geoscientists have the capability to understand the level of mathematics used to perform MCS and the complexity of this method.

- Solving problems by MCS has less chance of making mistakes compared with an analytical approach.

- There is commercial software available for the tasks involved in the simulation.

- Complex and nonlinear mathematics can be included in the model with no extra difficulty.

- Since MCS is widely recognized as a valid technique, the results of this method are more likely to be accepted by both analysts and decision makers.

- The behaviour of the model can be investigated easily.

- If there are some changes to the model required, it can be done quickly. Besides, it is possible to compare the results between before and after the model is changed.

3.3 Common Pitfalls in Performing Monte Carlo Simulation

Due to a great number of benefits of using Monte Carlo simulations, this technique becomes the preferred method compared to the deterministic approach for well forecasting. However, its potential to enhance the reliability of well forecast will be recognized only if the technique is applied properly. Williamson et al[31] have presented some observations of common concerns when using this technique.

- Model input should have appropriate level of detail. Based on different situations, the well can be modelled with the details of the well level, section level or job level. Depending on how the drilling performance is modelled, the same range of performance can lead to different overall drilling time. Thus, it is recommended that the input to MCS model should be basic quantities which are not derived from others. For example, to model the performance of drilling a hole section with an expected range of ROP is preferred compared to specifying the expected range of duration of the operation.

- It is important to determine the scope of the model correctly by deciding what items to be included in the model and which events to be ignored. For different well types, exploration or development, there are different operations which will affect the cost concerns. It is also important to decide which risk events should be included. A single well forecast may have less major risks than a multiwell program. Besides, one need to clarify what level of changes in work scope will invalidate the previous forecast and, at what level of details, they will be absorbed in the uncertainty of the model inputs. For example, if the geological objectives have changed, a revision in the well cost estimate might be required.

- There are two pieces of information required in order to have correct results from the forecast. They are the probability that the well is drilled in the time period in question (i.e. calendar year) and the probability that well construction is concluded successfully and not abandoned. If these probabilities are treated as zero, the model will have a build-in systematic error.

- When gathering the data for the simulation, the data set must be large enough to represent a full range of performance. Additionally, it must include only the data from the wells that are similar to the well that is subject to forecasting.

- Analysing the data by automatically rejecting the statistical outliers is not a good method. Investigation of abnormal results may highlight risks and/or opportunities that call for special attention.

- Sometimes poor performances are filtered out from the offset data sets due to the reason that poor outcomes are treated as specific events that will not occur again. This is not recommended.

- There are some items which can be missing from the work breakdown structure and so do the cost related to them. These items are often nonrig related, such as, insurance, corporate allocation and engineering support.

- If good offset data is absent, engineers could underestimate the range of possible value significantly. Even though good offset data is available, there are some common mistakes associated with parameters selection. The first common error is to define the minimum and maximum distribution value from the minimum and maximum of the data value. The extreme values of the input distribution must be wider than the extremes of the data set. Otherwise, the forecast will be based on the assumption that both the best case and worst case scenario have already been experienced in the data set. Thus, there could be an underestimation of uncertainty in the inputs and the predicted results. The second pitfall is to define the most-likely value from the mean or the median of the data set. The third pitfall is relying too much on calculated distribution parameters.

- In reality, there may be only few offset data points which are available and reliable as an indication of future performance. With small data set, the uncertainty in the calculated parameters will be large. This leads to large uncertainty in the predictions as well.

3.4 Dependencies

In MCS, it is assumed that all the input probability distributions in the model are independent. However, in reality, the value of a variable can depend on value of others. There are several methods which can be used to check the dependency of the input parameters. A common approach is using crossplots of the raw data and calculates the rank correlation coefficient, known as Spearman's rank-order correlation coefficient. A correlation value of +1 means that the two probability distributions are exactly positive correlated. On the contrary, a correlation value of -1 means that the two probability distributions are exactly negative correlated. A correlation coefficient of 0 implies that there is no linear relationship between the two distributions. Positive correlation value, between 0 to +1, produce varying degrees of positive correlations while negative correlation value, between 0 and -1, produce varying degrees of inverse correlations.[31],[6]

Some input parameters may be correlated to others since they are influenced by the common factors. For example, if the hole section takes longer time than expected to drill, the possibility of encountering problems while running casing of that section could also increase.[6]

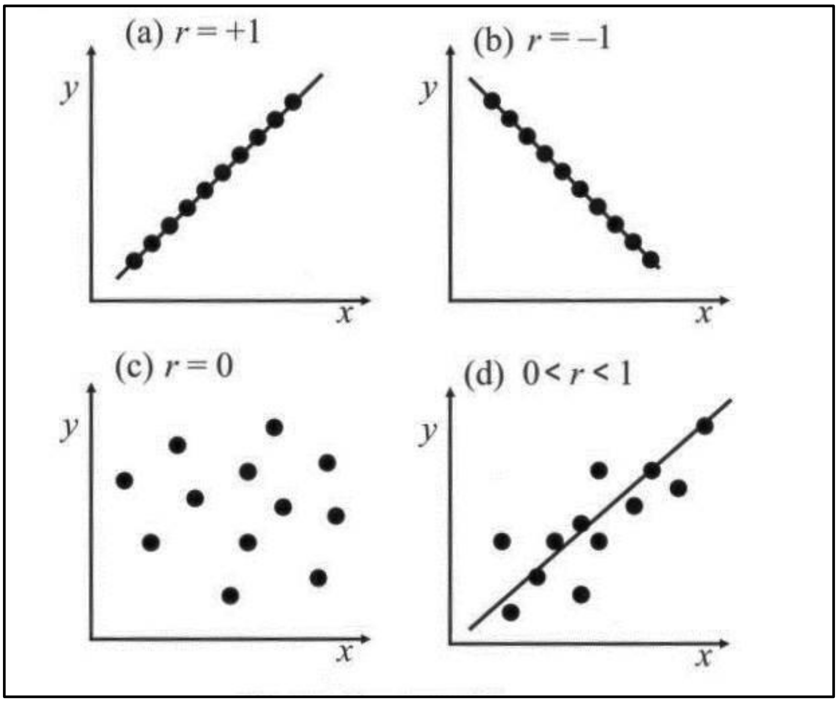


Figure 11: Linear correlation - Source: [6]

3.5 Example Calculation using Monte Carlo Simulation

Given that the section length to be drilled is 1,000m. Rate of penetration (ROP) of that section has a triangle distribution with minimum value of 5 m/hr, peak value of 20 m/hr, and maximum value of 35m/hr. Daily rig rental rate of semisubmersible rig has a uniform distribution with the minimum value of 4,000,000 NOK and the maximum value of 7,000,000 NOK. The Monte Carlo technique will be performed to estimate the cost of drilling this section.

- Defining the model

To make it simple, the model in this example consists of 2 equations which are:

Drilling time (hr) = section length/ROP

Drilling cost = Drilling time * Rig rental rate/24 + fixed cost

Fixed cost is assumed to be 2,000,000 NOK.

- Data gathering and probability distribution selection

Assume that, ROP has a triangle distribution with minimum value of 5 m/hr, peak value of 20 m/hr, and maximum value of 35m/hr. ROP input values drawn from the triangle distribution is shown below.

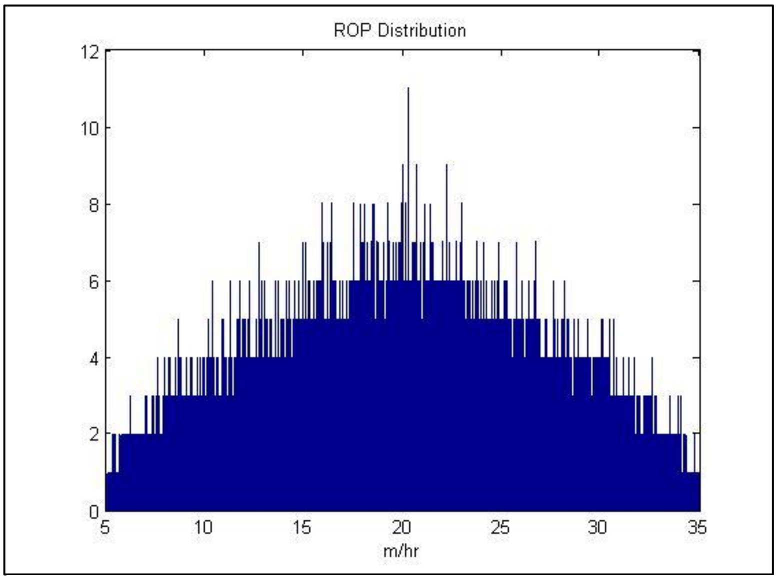


Figure 12: Histogram of ROP with normal distribution

Daily rig rental rate has a uniform distribution ranging from 4 million NOK to 7 million NOK. Rig rate input values drawn from the uniform distribution are shown below.

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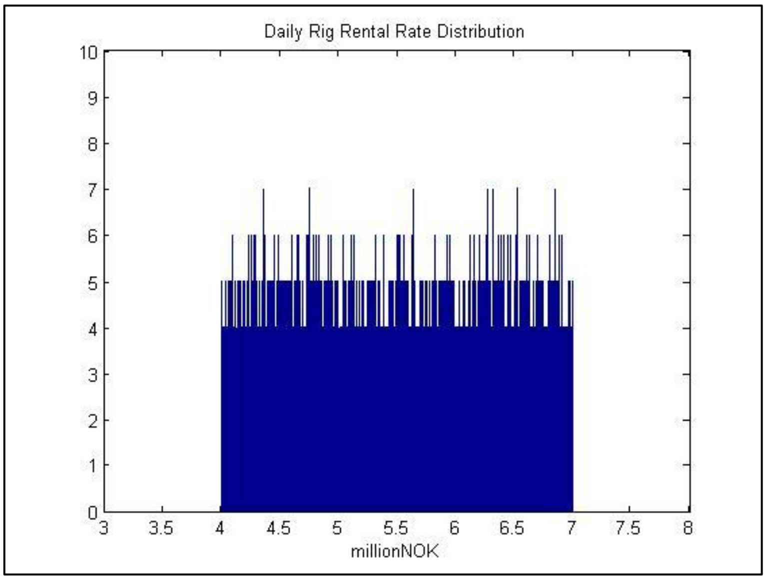

Figure 13: Histogram of rig rental rate with uniform distribution

- Randomly sample the input distribution

The input distributions are randomly sampled using 100,000 iterations. The code can be seen in Appendix.

- Compute the model results and generate statistics of results

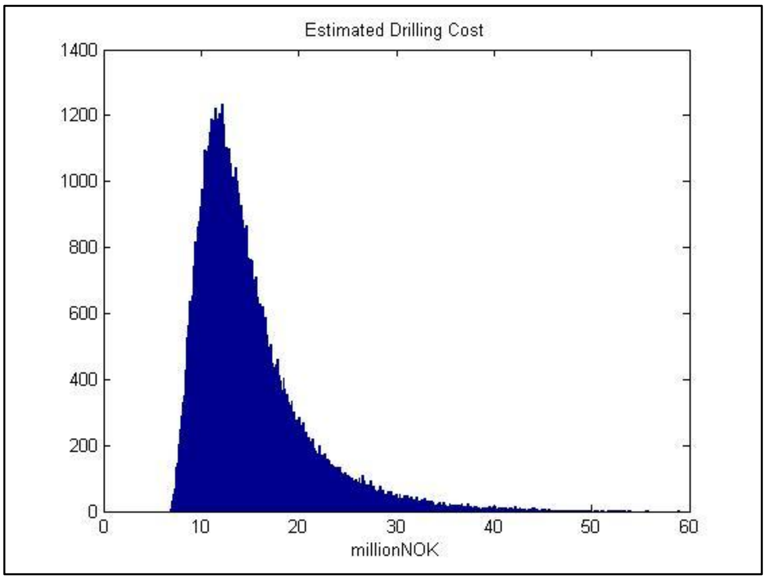

Figure 14: Histogram of estimated drilling cost

From the simulation results, we get an estimation of well cost as shown below:

Average = 14.86 million NOK

Median = 13.43 million NOK

Standard deviation = 5.59 million NOK

In case that there are some events occurring, the duration for well construction would increase. Here is an example of well time prediction with the risk of major events included. In this scenario, it is assumed that non-productive time (NPT) from the event has triangle distribution. The distribution has the minimum value of 2 hr, peak value of 30 and the maximum of 60 hr. The probability that the event will occur is 0.2. Other parameters are the same as in the previous example.

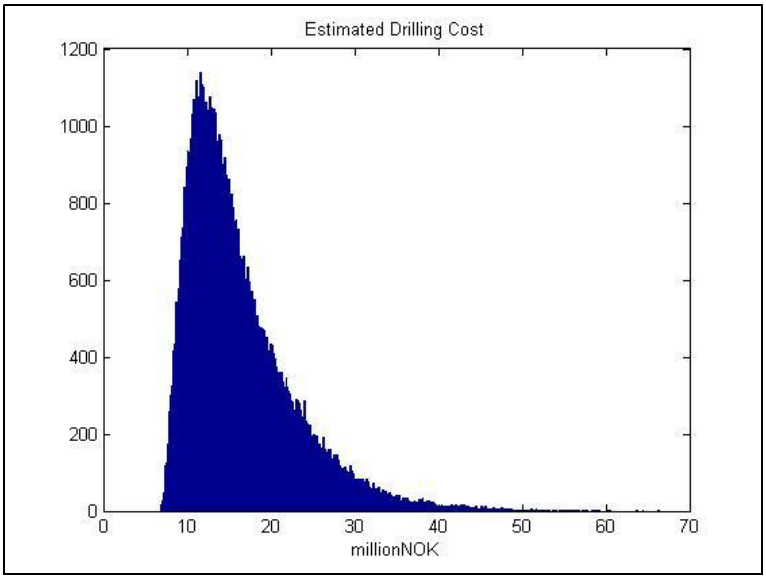

Figure 15: Histogram of estimated drilling cost with the risk of events included

Average = 16.28 million NOK

Median = 14.60 million NOK

Standard deviation = 6.48 million NOK

When comparing the results from both cases, we can observe an increase in an estimated drilling cost in case of included events (represent by its average and median). The uncertainty/spread in the cost estimation is also increasing reflected by the increase in SD.

3.6 Sensitivity Analysis

Sensitivity analysis (SA) is the study of how the variation in the output of a model (numerical or otherwise) can be apportioned to different sources of uncertainty. In the beginning, sensitivity analysis was created to deal with the uncertainties in the input variables and model parameters. Afterwards, the concept has been developed to combine model conceptual uncertainty, such as uncertainty in model structures, assumptions and specifications. Thus, sensitivity analysis (SA) is closely related to uncertainty analysis (UA).[32]

For Monte Carlo simulation, there are uncertainties in input parameters. Hence, it is important to conduct an analysis to determine the sensitivity of the simulation results to changes in the estimates of the input parameters.[6]

There are several methods of performing sensitivity analysis. Each technique has its strengths and weaknesses. One possible way is to divide sensitivity analysis into 3 classes which are screening method, local SA methods and global SA methods.[32]

For well cost estimation, a graphical method is frequently used as an effective tool for analyzing sensitivity, such as tornado diagram. Tornado diagram represents the results of a single-factor sensitivity analysis. Single-factor analysis implies the measurement of effects on the outcome of each factor, one at a time, while keeping the other parameters at their base value. One-at-a-time (OAT) approach is the simplest class of screening designs. Besides, one can also see local SA as a particular case of the OAT approach. OAT designs are classified into several categories and the tornado diagram is the standard OAT design where one factor is varied from a standard condition. [32]

Tornado charts deal with single objective and multiple uncertainties. It is used to evaluate the sensitivity of a single output variable to changes in multiple inputs. It also helps decision makers to determine 2 decision-driver types: uncertainty drivers and value lever.[6]

- *Uncertainty drivers* are the model-input variables which have the highest impact on the results. This technique enables quick screening of multiple uncertainties at an early stage. It also suggests where the budget should be spent on further data collection and technical analysis.

- *Value Levers* are models input parameters which have most impact on the estimation.

These can help the team decide which parameters to be focused on in order to optimize the decision.

Figure 16 shows the result of sensitivity analysis on the sub operation level of well construction cost. From this tornado diagram, mobilization and positioning the rig is the most important operation regarding the cost. The figure also shows the ranking of the ten most important sub-operations.

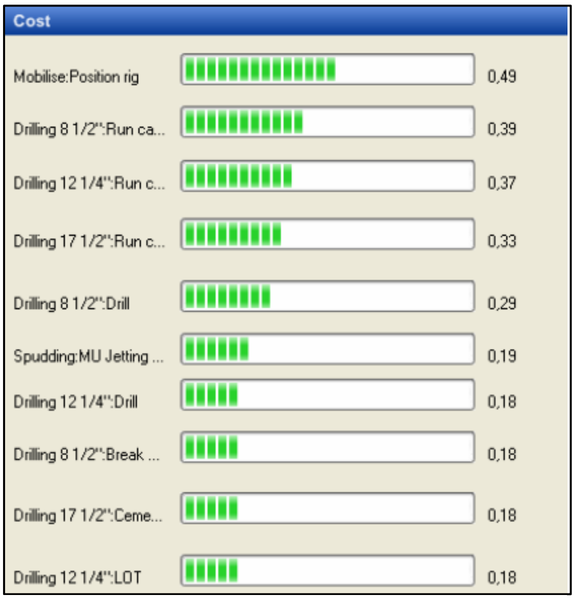

Figure 16: Cost sensitivity analysis. - Source: [7]

4. Major Risk Events that Cause Delay in Well Operations

Well construction cost consists of 2 main parts which are fixed cost and time-related cost. The latter is a significant part of the total well cost. Thus, accurate forecast of well construction duration is necessary for budget planning and effective performance management. There are some major risk events which result from known risks. These events are considered severe enough to delay the construction process of the well and should be included in the model for better accuracy of the prediction. Typical major risk events are described below.

4.1 Kick

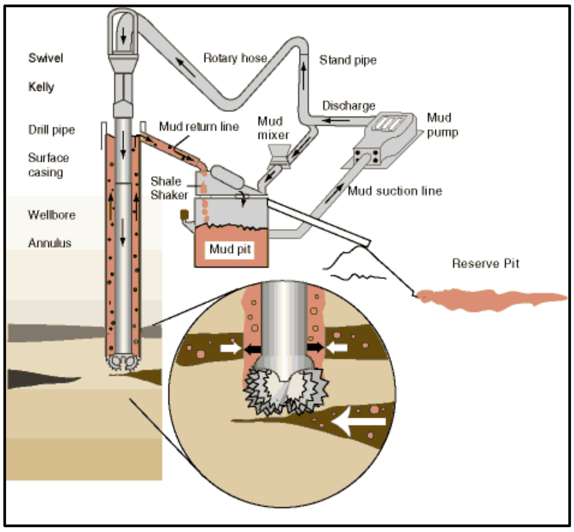

Figure 18: Kick illustration – drill bit hit high - Source:[5]

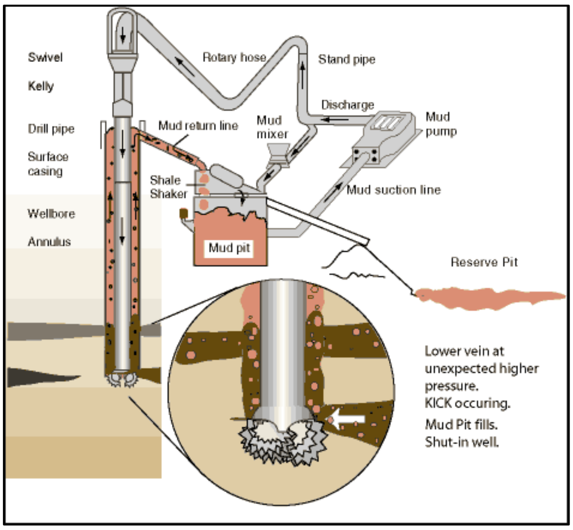

Figure 17: Kick illustration – KICK occurring. - Source:[5]

Drilling is a process of penetrating into formations. These formations contain fluid under pressure in pore spaces. Generally, this pressure is overcome by the drilling fluid pressure in the wellbore which is the result of the hydrostatic pressure and the frictional pressure loss in the annulus. If the borehole pressure falls below the formation pore pressure, it can lead to undesirable influx of formation fluid into the wellbore. This event is known as a kick event.

4.1.1 Causes of Kick Incidents

Below, some causes that can lead to a kick event are described. [33]

- Abnormally high formation pressure is encountered. If formation pressure of these zones is higher than current mud weight in the well, it will result in a kick event.

- Severe lost circulation occurs. This causes the wellbore hydrostatic pressure to decrease and, as a result, formation fluid enters the wellbore.

- Mud weight is too low. When drilling fluid density is too light, mud column cannot provide enough hydrostatic pressure to overcome the formation pressure. Thus, kick will occur.

- Swabbing effect caused by too high tripping rate out of the well or due to heave effect.

- The well is not filled up during pulling out the drillstring.

- Circulation of gas cut mud up in the well can lower the hydrostatic pressure below the formation pore pressure.

Failure to control kick could result in a blowout. In case of blowout, a great deal of effort, time and money would be required to handle the situation.

4.2 Stuck pipe

Stuck pipe is the situation where a part of the drillstring, such as drill pipe, drill collar or BHA, becomes immobile in the hole. The drillstring can neither be rotated nor moved vertically. This situation can happen during drilling, making connection, testing, logging or any other operations as long as the drillstring is still in hole. In general, when circulation stops, the risk of getting stuck increases.

4.2.1 Causes of Stuck Pipe Incidents.

- **Insufficient hole cleaning**: During drilling, cuttings are circulated out of the borehole by drilling fluid. If the circulation rate is too low and/or the drilling fluid has inappropriate properties, cuttings will be left in hole. They will settle and accumulate around the drillstring. This could result in stuck pipe incident. Some notifications of pipe getting stuck are poor amount of cuttings on shaker and an overpull while tripping.

- **Wellbore instability**: Wellbore instability is an event where some formations become unstable and the borehole does not maintain its size, shape or structural integrity. Due to failure in rock mechanisms, fragments of rock fall into the wellbore and accumulate around drilling BHA. Problems regarding wellbore instability are more common in the following conditions: [34]
    - Shale zones with high percentage of swelling clays such as sodium montmorillonite.
    - Steeply dipping or fractured formations such as limestone.
    - Overpressure shale zones.
    - Turbulent flow in an annulus leads to washouts situation in soft formations.

- **Mobile formation**[2]: Mobile formation is caused by overburden stress from the rocks above squeezes shale or salt into the wellbore. Salt or shale move into the wellbore and plug the annulus. Hence, the hole becomes undergauge and the drillstring gets stuck. This could be noticed by an increase in mud chloride content and an overpull during the connections.

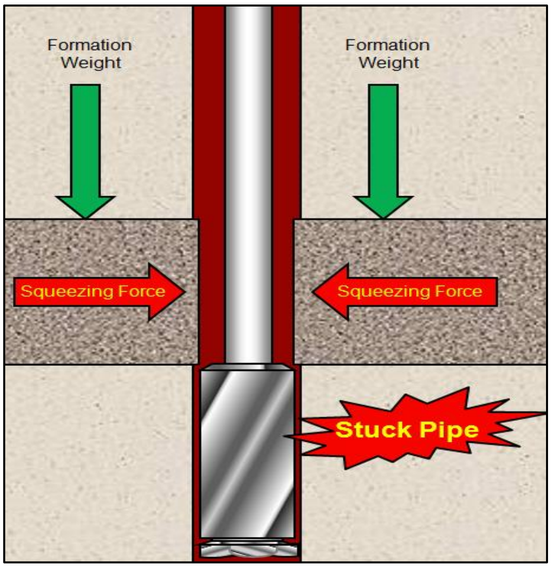

Figure 19: Mobile formation causes stuck pipe incident – Source: [2]

- **Differential sticking**[34]: In general practice, the borehole pressure is kept higher than the formation pore pressure in order to prevent an influx of formation fluid into the wellbore. Thus, in permeable zones, drilling mud invades the formation and the solid part of it builds up on the borehole wall creating the mud cake. Differential sticking occurs when the mud cake becomes thick and the drillstring rests on the low side of the hole and becomes sticking with the mud cake. The chance of the pipe getting stuck is increasing if the drillstring is left stationary for a period of time. In addition, it will be more difficult to free the stuck pipe if the differential pressure is larger than 1,000 psi.

- **Keyseating:** When the drillstring passes the severe dogleg part of the well, the pipe will make contact with the borehole wall and rub against the formation. If drilling is continued with the drillstring in this position, it will wear a groove on the formation wall. The problem occurs while tripping out of hole. The small drill pipe may pass through the keyseat but the larger drill collar and BHA can become stuck at the narrow groove. This kind of pipe sticking is more likely to occur in soft formation.

- **Undergauge hole**: Drilling through long abrasive formation could defect gauge protection on the bit. Thus, the hole becomes undergauge. While tripping in the new bit, it is possible that the new bit gets stuck in an undergauge section.

4.3 Wait on Weather (WOW) or other environmental interruptions

The ocean environment or sea conditions can have large effect on offshore operation performance. The effects of winds, rough seas, wave height and other elements can cause delay in drilling operations. Delays caused by these conditions are commonly referred to as "waiting on weather". It is usually calculated as a percentage of total time. Normally, it is included into the cost prediction models as a variable since the amount of expected WOW will depend on the time of the year that the operation will take place. [17] ,[35]

4.4 Downhole tool failure

The bottom hole assemblies (BHA) of the drillstring is composed of many downhole tools connected to one another. Since BHA failure is one of the largest sources of non-productive time (NPT), ones might try to minimize the probability of downhole tool failure with several preventive means. However, prediction of BHA failure is still a complicated problem. Besides, high weight on bit (WOB) or rotational speed applied to BHA in order to optimize rate of penetration (ROP) may induce shocks and vibrations on the drillstring. BHA components could be rapidly destructed due to the operating condition at or close to resonance. High stresses generated will lead to very short fatigue life. Despite the fact that there are many factors which cause BHA failure, harmonic vibration, especially lateral vibration, plays a significant percentage on field failures. Severe downhole vibration can be responsible for many BHA problems such as: [36],[37]

- BHA washouts
- Twistoffs
- Premature bit failure
- Accelerated failure of downhole equipment.
- Excessive wear on tool joints

These problems can lead to failure in BHA components and it may require tripping to change components. In that case, it will lead to extra expenses associated with replacing failed component and extended rig time. A tripping operation can easily take half a day and, with the current rig rates, this will represent a significant cost.

4.5 Lost Circulation

Lost circulation is the reduced or total absence of fluid flow up the annulus when fluid is pumped through the drillstring. [12] This reduction of flow may generally be classified as: [38]

- Seepage loss – Lost rate is less than 20 bbl/hr (3 m^3/hr).
- Partial loss – Lost rate is greater than 20 bbl/hr (3 m^3/hr) but there are still some returns.
- Total loss – There's no fluid returns from the annulus.

This incident is detected at surface when the mud return rate from the annulus is less than the pump rate into the wellbore. Lost circulation occurs when: [39]

1. Extremely high permeability formations are encountered, such as gravel bed or vugular limestone.
2. A fractured formation is encountered or created due to excessive wellbore pressure.

If the lost circulation incident is severe and the total loss occurs, the hole may not remain full of fluid even if the pumps are turned on. This leads to reduction in the vertical height of the fluid column. As a consequence, the pressure exerted on the open formations is reduced. While the loss zone is taking mud, there can be formation fluid from other zones flowing into the wellbore creating a crossflow situation. In such a severe situation, a catastrophic loss of well control could be the result.

Even in the two less severe forms, the loss of fluid to the formation represents a financial loss that must be dealt with, and the impact of which is directly tied to the per barrel cost of the drilling fluid and the loss rate over time. Lost circulation is one of the most time consuming and costly problems associated with the drilling fluid. It has been estimated to cost the drilling industry over one billion dollars annually in rig time, materials and other financial resources.

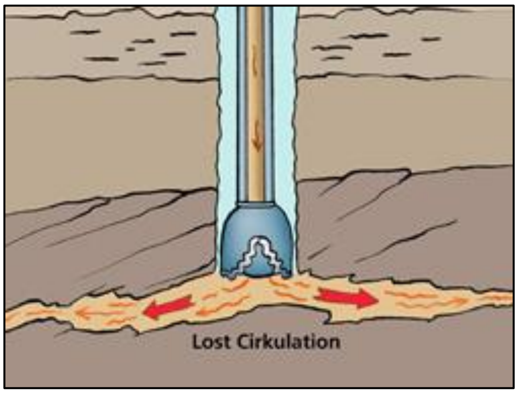

Figure 20: Lost circulation - source:[1]

4.6 Shallow gas

While drilling top hole section without a riser, the operation is subjected to risk of shallow fluid flow. This situation is not possible to control by shutting in the well. Influx of shallow gas into the wellbore is a challenging problem. Most shallow gas kicks result in blowout. Handling this situation is one of the most complex well control challenges during drilling operation. Not only serious safety issues regarding operation personnel and rig, shallow gas blowout can also lead to huge financial losses, especially shallow gas blowout on a platform. As a consequence, the regulations of some countries require drilling of narrow pilot hole before opening the hole for the upper casing program.[40],[41]

5. Simulation Tool

To perform well cost estimation by the probabilistic method, there are several software or simulation tools being used. Some of the software which is available in the market has been mentioned in the theory part. In this thesis, the Risk€ software is the simulation tool used for the well construction time and cost prediction. The description of the software will be based on [18], the user manual and the explanation given inside the software.

Risk€[18] is a software developed by International Research Institute of Stavanger (IRIS) with financial support from ENI. It is a user-friendly tool that provides probabilistic cost and duration estimation of the well.

5.1 Benefits of Risk€ Software

This is taken from [18].

Makes work processes more effective through:
- Easy to do the calculation in-house
- Easy to automatically generate reports
- Easy to systematize expert input

Facilitates both internal and external communication:
- Can be used for field-to-field comparison
- Can be used for communication in a license setting
- Easy to communicate to decision-makers

Supports technical decisions:
- Risk management in a cost perspective
- Reduce costs and duration related to well construction

5.2 Applications

The software utilizes Monte Carlo simulation along with sensitivity analysis to help the decision makers and users determine the overall cost and duration as well as the project uncertainties. The results from Risk€ also support AFE approval. The total cost and duration probabilistic estimate of the whole well construction processes is achieved by the summation of probabilistic cost and duration of all phases and sub operations. This can be described by two equations shown below.[7]

$$\boldsymbol{C = C_1 + C_2 + \ldots + C_n} \quad (21)$$

where C is the total probabilistic cost of the well construction, C_1, C_2, …, C_n are the costs of performing sub-operations 1,2, …, n respectively and n is the number of sub-operations.

$$\boldsymbol{D = D_1 + D_2 + \ldots + D_n} \quad (22)$$

where D is the total probabilistic duration of the well construction, D_1, D_2, …, D_n are the durations of performing sub-operations 1,2, …, n respectively and n is the number of sub-operations.

Many undesirable events associated with the drilling operations can be added to the simulation. The results of additional cost and duration from these events are added in the same manner in the two equations mentioned above.

The simulator divides the well construction processes into phases, i.e. mobilization of drilling rig, spudding of the well, BOP installation, drilling hole sections and well abandonment. User provides input regarding probability distribution type and value of each parameter. The software will simulate the result of the standard operation plan based on user input. The user can also specify if 10,000 or 100,000 iterations are required for the Monte Carlo simulation.

5.3 Input of Drilling Phases for Generation of Standard Operation Plan

Once a well is created in Risk€ and its drilling environment has been identified, the next step is to describe the well architecture. After that, the user will work with the well standard operation plan and the risk operation plan. In Risk€, the standard operation plan is the plan for drilling activities without any undesirable events.

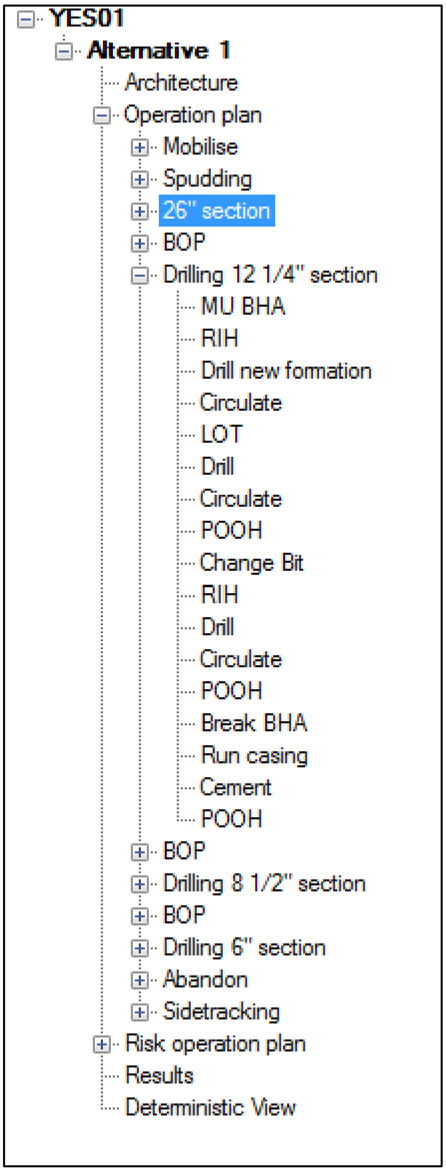

Figure 21: Snapshot of operation plan automatically created in RiskE

The Risk€ software divides the well operations into 5 main phases which are:

- Mobilization Phase
- Spudding Phase
- BOP Installation Phase
- Drilling Phase
- Abandonment Phase

Each phase consists of a list of sub operations, both automatically generated from the software and manually added by the user.

In the input panels, user chooses the type of probability distribution for cost and duration of each sub operations. The technology applied in the operation is also selected. Here are some input panels of each operation phase.

5.3.1 Well Architecture

The well architecture is an editor for the casing description of each section, including the length and diameter of an open hole section. The details related to casing shoe depth, casing hanging point, casing outer diameter (casing OD), and casing inner diameter (casing ID) are specified here. From that information, a wellbore schematic of the well to be simulated can be drawn.

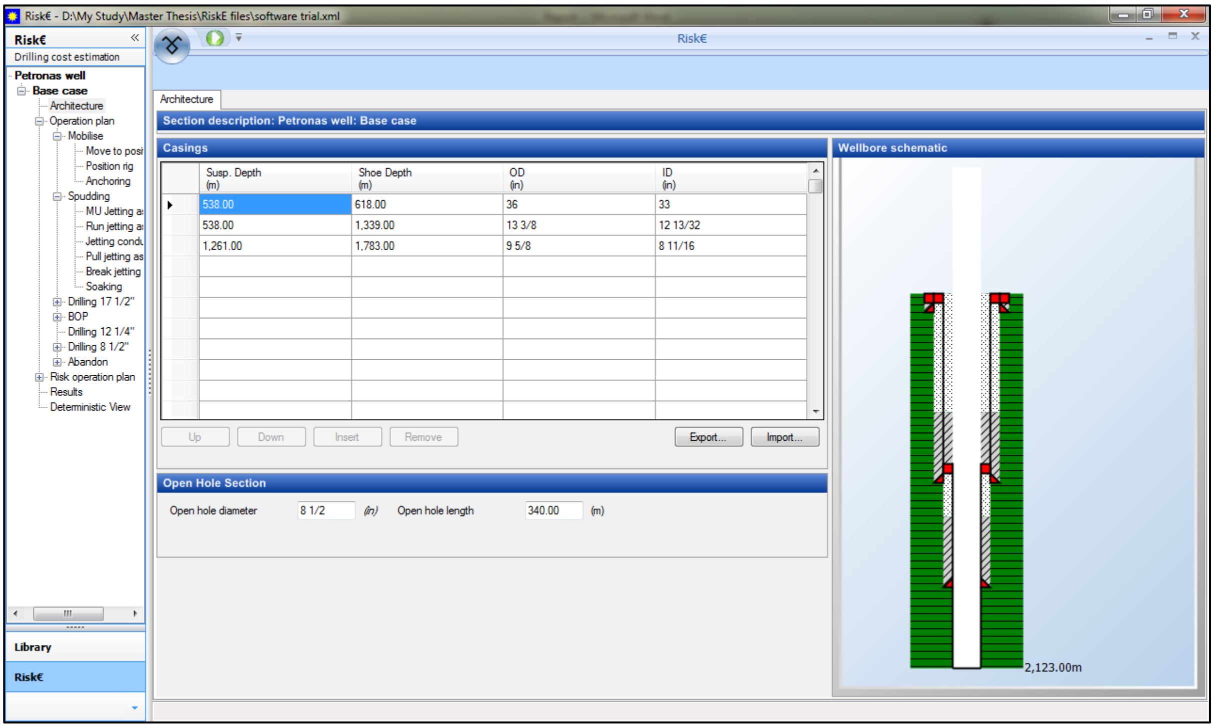

Figure 22: Input panel for well architecture

5.3.2 Mobilization of drilling rig

In this panel, the user needs to specify the technology used for rig mobilization on the left hand side of the panel. Each rig mobilization technology requires different input information. The classes of technology which are available for choosing in this software and its input are listed in the table shown below:

Mobilize Rig Technology	Information Required
Mobilize Rig Jack Up	Distance to location, Moving velocity, Duration for positioning rig, Jack up distance and velocity, Cantilever distance and velocity
Mobilize Rig Platform	Distance to skid rig, skidding velocity
Mobilize Rig Land Rig	Distance to location, Moving velocity, Rig up duration, Distance to skid rig, Skidding velocity
Mobilize Rig Semi Sub	Distance to location, Moving velocity, Duration for positioning rig, Anchoring duration
Mobilize Rig Floater	Distance to location, Moving velocity, Positioning rig duration

Table 2: Mobilize rig technology and its input information – Source:[42]

In every phase, there is an input panel for cost related information. In this panel, there are 6 types of cost related information which need to be filled in which are:

- Rig rate - The cost rate of the rig that is used for the well construction.
- Drillstring/BHA costs - The cost rate for the drillstring including the bottom hole assembly.
- Fixed cost – Fixed cost related to: Site survey, Rig positioning, Rig mobilization/ demobilization, Vessels mobilization/demobilization, different types of logging (e.g. electric logging, cased hole logging), Insurance, Fishing and abandon services, Well planning.
- Spread rate – The sum of the cost related to: Vessels, Additional (catering etc), Cement services and personnel, Mud logging, Conductor driving equipment, Dock fees & base overheads, Rental tools, Consultants on rig, ROV, Water, Fuel (including rig and vessels).
- Wellhead cost - The fixed cost for the wellhead for the phase taken into consideration.
- Support cost - The cost rate related to: Drilling Office overhead, Office Support consultant, Other drilling expenses, Air transport

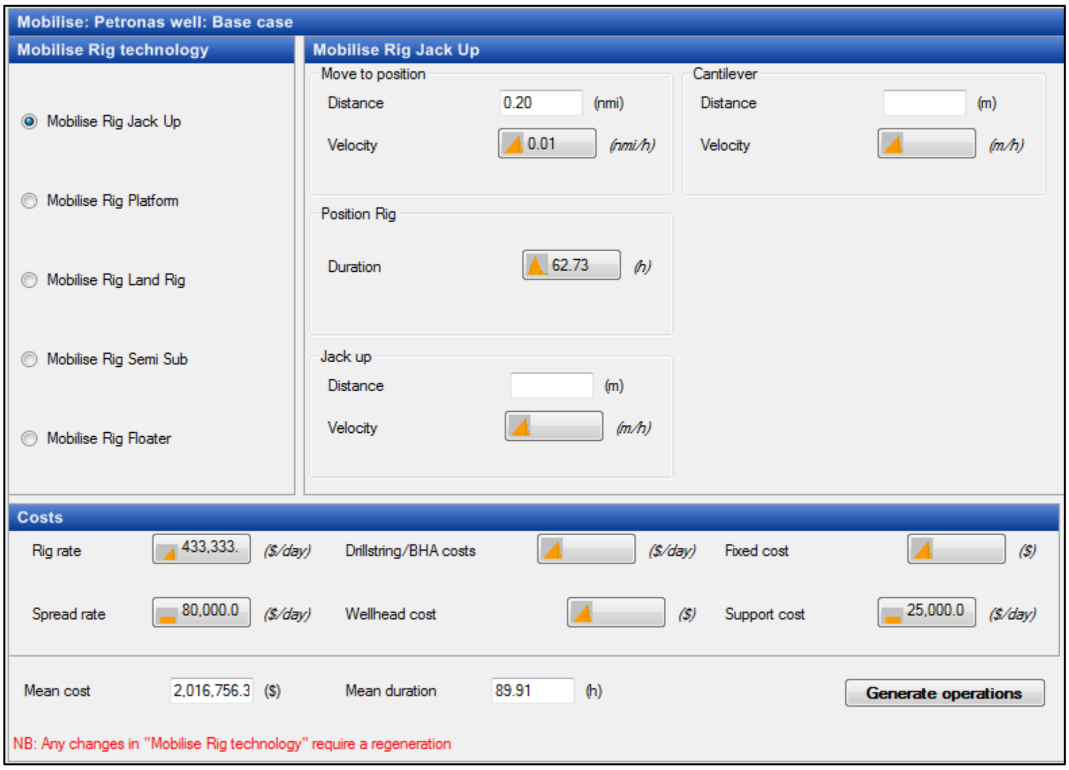

Figure 23: Mobilization phase input panel.

5.3.3 Spudding

Spudding phase is an operation being conducted in an early stage of drilling a new well. This is where we drill the top hole for installing a conductor which would form the fundament for the rest of the well. There are 3 main technologies for making this top hole and run the conductor. Jetting is the technology where a high-velocity and high-pressure fluid stream is used to make hole in the ground before the conductor can be run. Hammering means that the conductors are hammered down into the ground without drilling the hole first. Top hole refers to the methodology of drilling the hole first, then running the conductor.

Spudding Technology	Information Required
Jetting	Time to MU and break jet assemblies, RIH and POOH speed
Hammering	Time to rig up and rig down
Top Hole	Time to MU and break BHA, RIH and POOH speed, ROP, Bit cost

Table 3: Spudding technology and its input variables

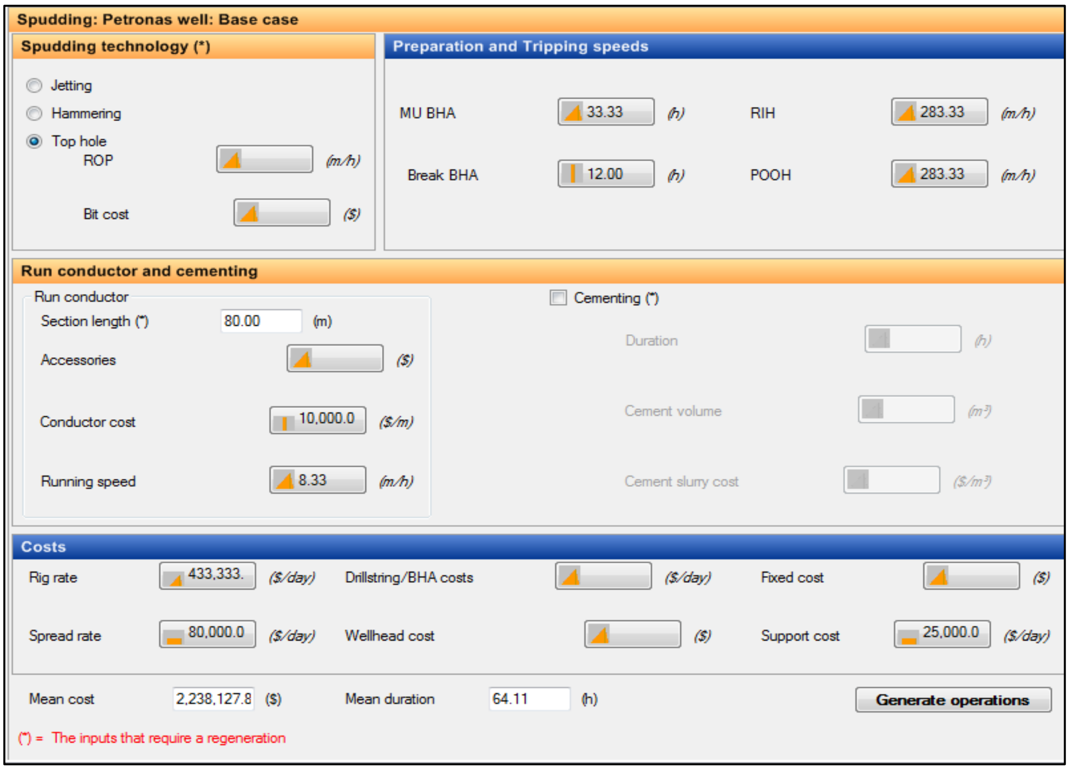

Figure 24: Spudding Phase Input Panel

5.3.4 Drilling hole sections

The input panel shown below is used for generating the different drilling phases in a well, e.g. drilling and casing setting of surface section 26", 12 ¼",and 8 ½".

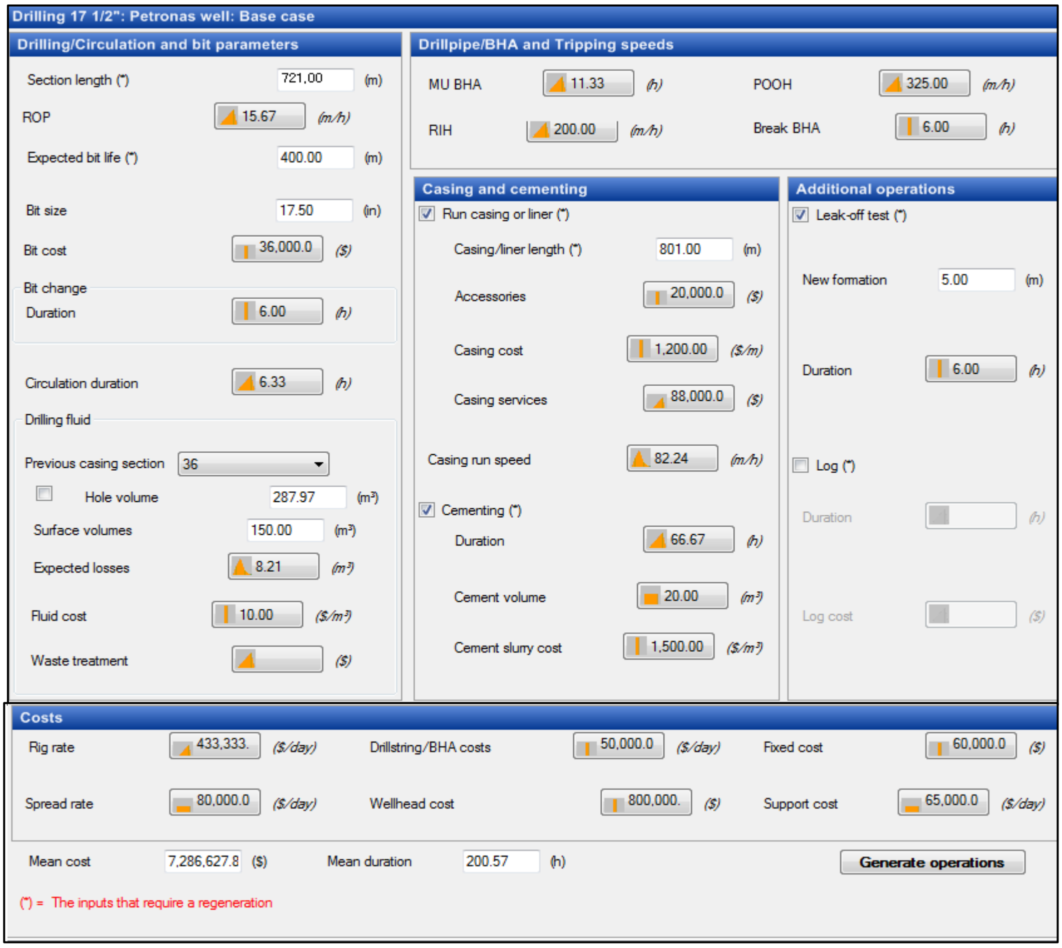

Figure 25: Drilling phase input panel

5.3.5 BOP Editor

For BOP editor, there's only one difference between installing BOP at surface and sea bed. On a platform well, the BOP will be on surface. When using a semisubmersible rig and drilling in deep water, the BOP will be installed on seabed. In case of subsea BOP, the time required to run BOP and riser is added.

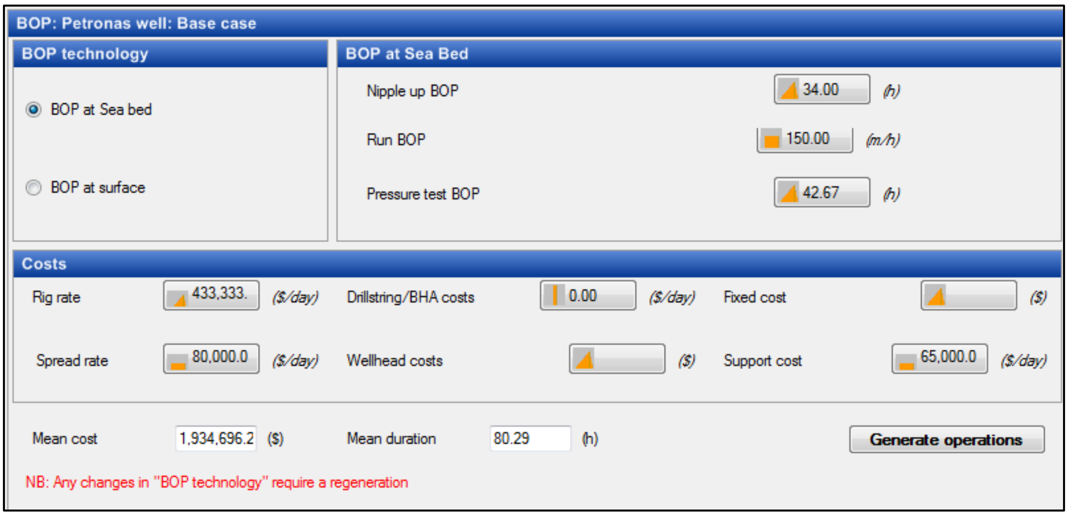

Figure 26: BOP editor input panel

5.3.6 Distribution Mode Input

Users can choose which type of distribution is the most suitable for that parameter. This could be based on expert judgments and/or historical data. The common distribution types used are single value distribution, uniform distribution, triangle distribution, piecewise linear distribution and discrete distribution. However, more advanced distributions such as generic distribution, Gaussian distribution, exponential distribution and Weibull distribution are also available in this software. The generic distribution mentioned here refers to the distribution which the distribution curve is constructed based on a set of data. This distribution type is suitable when it is difficult to define the distribution type and the historical data is available.

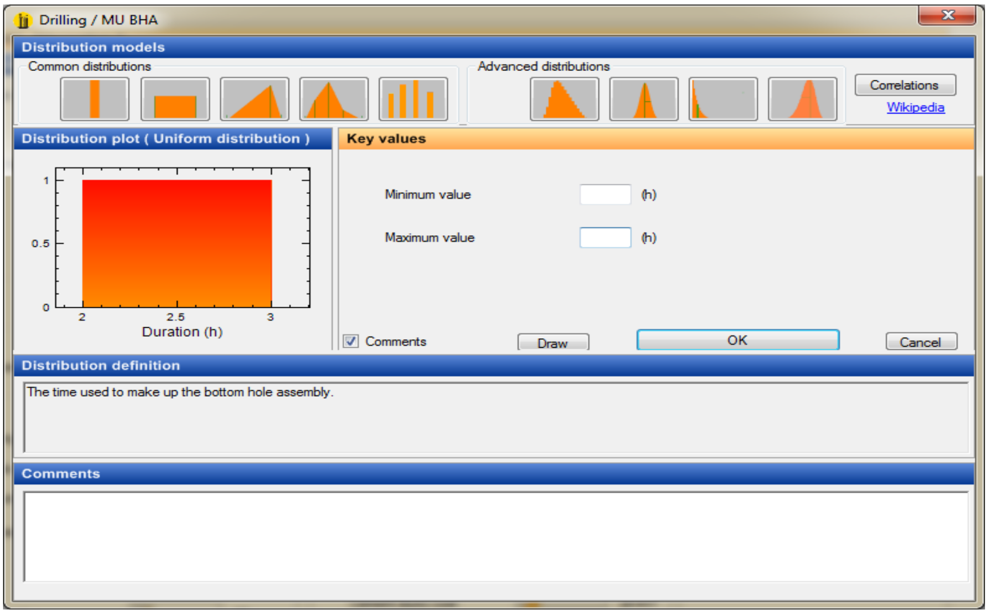

Figure 27: Distribution Mode Input Panel

5.4 Input of Risk Events for Generation of Risk Operation Plan

Risk operation plan is the operation plan where the effects of undesirable events are included in the prediction. The consequences of these risks are reflected in the predicted results which could be compared with the risk free operation plan.

The risks associated with drilling activities can be categorized as events in the well level or events in phase level. The user defines extra duration and cost caused by the events and then, specifies the probability of occurrence.

5.4.1 Risk Events in Well Level

Risk events in the well level refer to any undesirable events which can occur throughout the well construction processes, not limited to any operation phases. Some examples of risk events, taken from the Risk€ library description and the software user manual, in well level are:

- Wait on weather - Delays due to bad weather stopping operations on rig. Typically strong winds will prevent using cranes etc.
- Wait on rig repair - Time and money spent repairing the rig. The duration is only when operations has to be stopped because of the repairs.
- Wait on material - Operations will be delayed if the correct materials are not present on the rig at the needed time.
- Drawwork failure - Drawwork failure will delay operations.

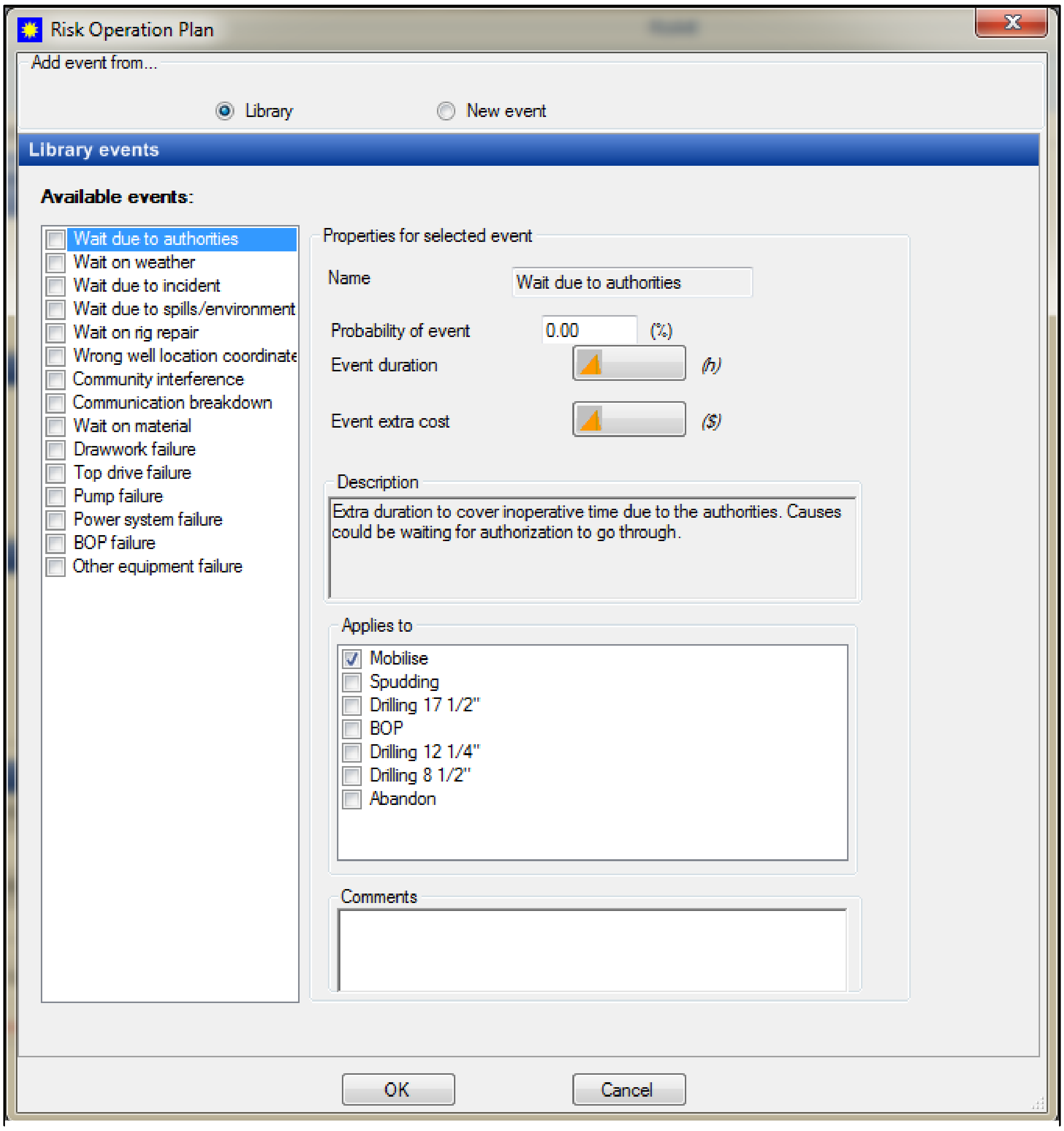

Figure 28: Input panel for risk events in well level

5.4.2 Risk Events in Phase Level

In each operation phase, there are some phase specific risks. These events are related to the activities being conducted in that phase and not likely to occur during other phases. Here are some examples of undesirable events in each phase.[42],[43]

Mobilization Phase

- Tug vessel problems - A vessel tugging the rig to position has a problem (e.g. engine failure, propeller failure etc.) causing delay. Is most relevant when moving the rig to location and also when positioning the rig.
- Interference with subsea facilities - Existing structures on the seabed, such as

flowlines, jumpers or shipwrecks, can be encountered during anchoring and spudding operations. This can cause delays and may also cause damage to the facilities and/or rig.

- Anchor handler vessel problems - The vessels used during the anchoring encounter problems such as vessel is inadequate for the task, engine failure or propeller failure. These problems will cause delays during the anchoring operation.
- Currents - Strong currents might cause delays, particularly when positioning the rig.
- Weather - This event covers weather effects not included in wait on weather, but can cause specific problems during the mobilize rig phase.

Spudding[42],[43]

- Poor visibility at seabed - If the visibility of the seabed is poor, lowering the jetting tool to the correct location on the seabed might take some extra time.
- Stuck conductor - During jetting the conductor the conductor can become stuck when the jetting progress stops, and it might be impossible to move/retrieve the conductor due to excessive friction and over pull. The delay caused by this will vary between working the conductor free and re-spudding the well.
- Conductor inclination problems - The conductor can be spudded at an unacceptable inclination. Too high inclination of the conductor can create problems landing wellhead and/or BOP, and could cause internal casing wear and additional bending forces / load and wear on the connectors, BOPs and/or riser. In some cases a re-spud is necessary.
- ROV failure - The ROV has problems causing delays when setting the conductor.

Drilling[42],[43]

- Stability/Collapse problems - Collapse of the hole can lead to stuck pipe, stuck casing, unable to extend casing point to desired depth. It can occur due to seawater drilling fluid and long open hole section. Additional time for circulating, reaming and wiper trips must be expected.
- Shallow gas - Shallow gas can be encountered while drilling the hole sections just below sea bed. Presence of shallow gas can result in an uncontrolled flow of gas

endangering the hole, the rig and the personnel.

- Stuck casing - During running casing the string can become stuck above the setting depth. Subsequently the hanger will be above the well head and cannot be set.
- Packoff - During running casing and cementation pack off, i.e. plugged wellbore around the drillstring, can occur. This can happen for a variety of reasons, the most common being that either the drilling fluid is not properly transporting cuttings and cavings out of the annulus or portions of the wellbore wall collapse around the drillstring. When the well packs off, there is a sudden reduction or loss of the ability to circulate, and high pump pressures follow. If prompt remedial action is not successful, expensive episodes of stuck pipe or lost well and re-spud might be the result.
- Improper cement job - If the casing is not well enough cemented to the formation, actions must be taken to better cement the casing. Typical actions include squeeze cementing.
- MWD/LWD/BHA failure - If the measurement devices fails, extra time will be spent either drilling slower, re-log section or trip out to fix the problem. The time will depend on when the failure occurs, from at rig floor to when you are drilling.
- Stuck pipe - If the pipe gets stuck due to for example mechanical sticking, differential sticking or pack off, effort must be taken to attempt to pull it loose.

BOP[42],[43]

- Currents - Strong currents can prevent running the BOP stack, and also using ROV.
- BOP/Riser equipment problems - BOP and riser equipment problems resulting in waiting to run the BOP's or waiting to land the BOP because of bad weather. BOP stack problems revealed during the testing of the BOP system resulting in pulling the BOP and repair and re-test at the rig.
- Unable to pressure test BOP - Unable to pressure test the BOP due to problems with seals on test tool or wellhead connector. Max time is to pull and rerun the BOP. Additional time to repair and possible extra time to transport spare part from shore to the rig might also be needed.
- Poor visibility at seabed - Poor visibility leads to delays due to difficulties to observe operations at seabed.

Abandon[42],[43]

- Cement unit/job problems - Cement unit problems during the job or bulk cement, spacer and mix water delivery, air compressors, etc.
- Inability to set cement plug - Contaminated cement or non-adequate pumping schedule might prevent setting the cement plug. The cement plug can also be set in the wrong place whereas it has to be reset, or the cement does not harden properly.
- Weather - Weather effects not causing wait on weather, but impede the abandonment operations in other ways.

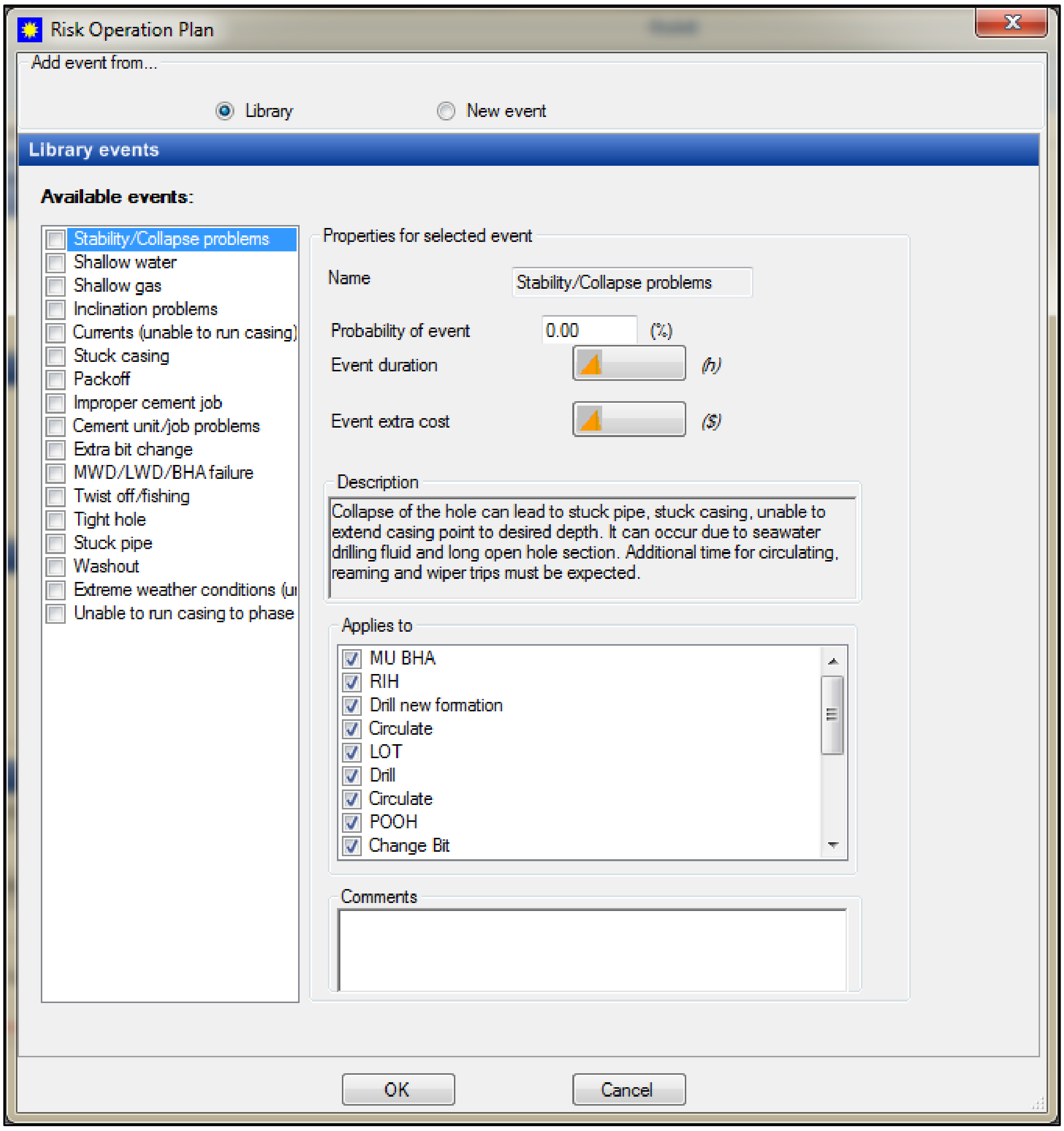

Figure 29: Input panel for risk events in phase level

After all the associated risks are added to standard operation plan, a risk operation plan is generated. Thus, the result of risk operation plan can be simulated and compared with the result of the standard operation plan.

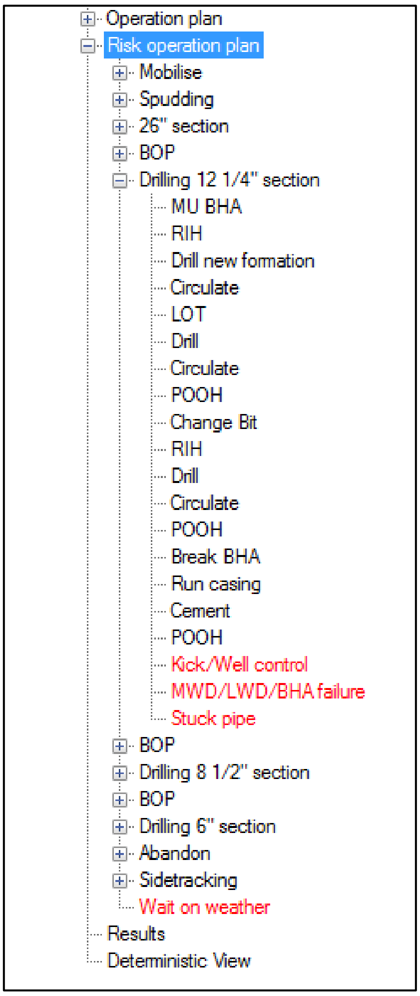

Figure 30: Snapshot of risk operation plan

5.5 Simulation Results

The simulator offers probabilistic results from both the standard operation plan and the risk operation plan. The latter case is available when the user has included the risk events in the standard operation plan. The results of cost and duration are presented as probability density function in a histogram shape. The main results provided by the simulator are:[18]

- Curves representing the mean duration and the mean cost, obtained analytically from the input distributions versus the deterministic drill depth.
- Drill depth versus time curves.
- The probability distribution for the total drilling cost and duration is given using a histogram, including summary statistics such as the maximum values, mean, and standard deviation.
- The probabilities of performing the well construction within user defined cost and time limits.
- Sensitivity analysis based on correlation coefficients
- Sensitivity analysis based on cost and duration contribution
- Cost breakdown
- Comparison of different well design
- Sensitivity analysis on phases, operations and events level

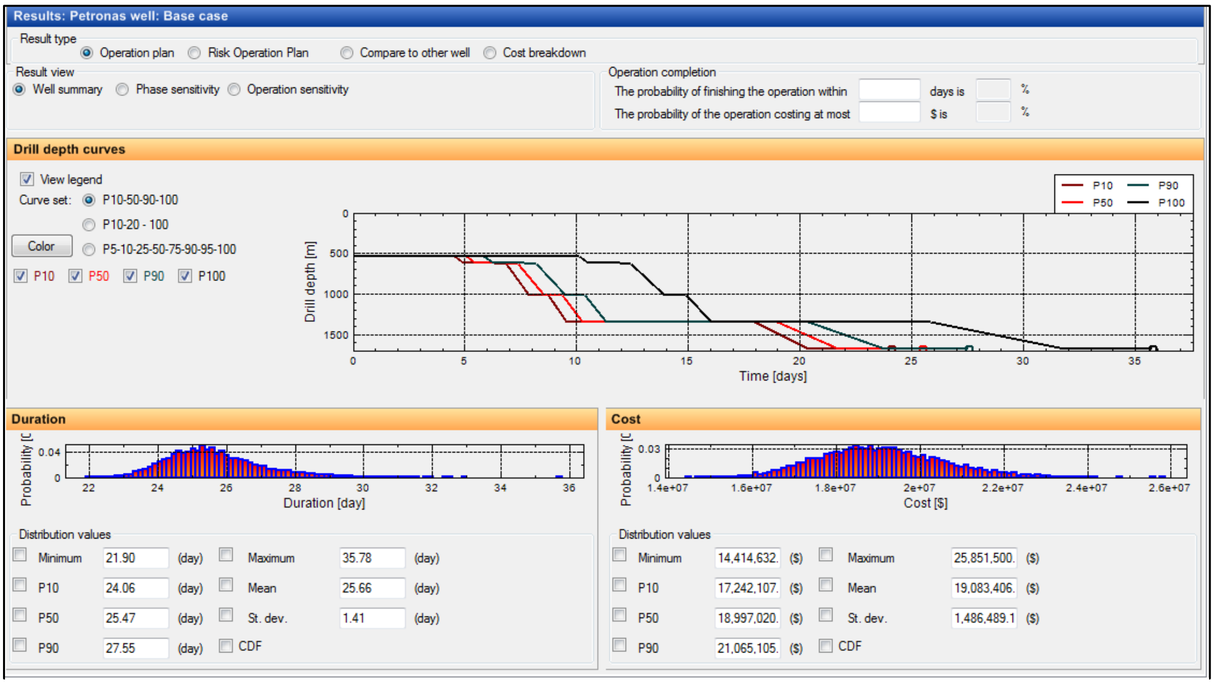

Figure 31: Well summary result

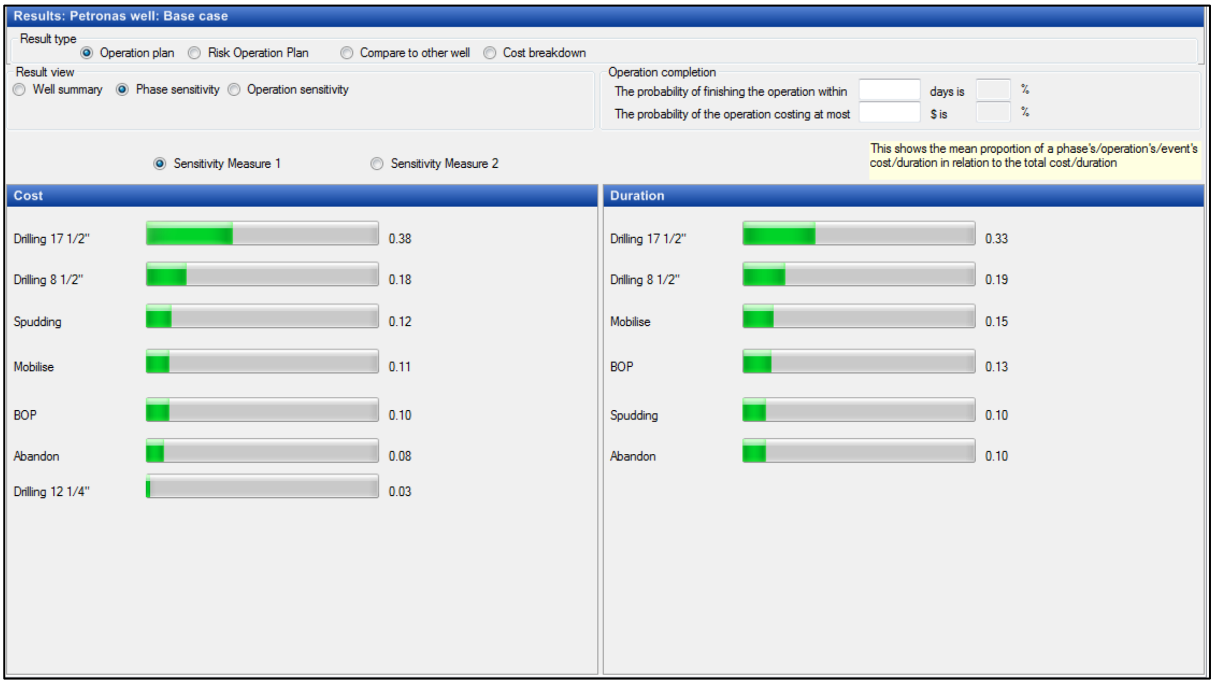

Figure 32: Result view of phase sensitivity

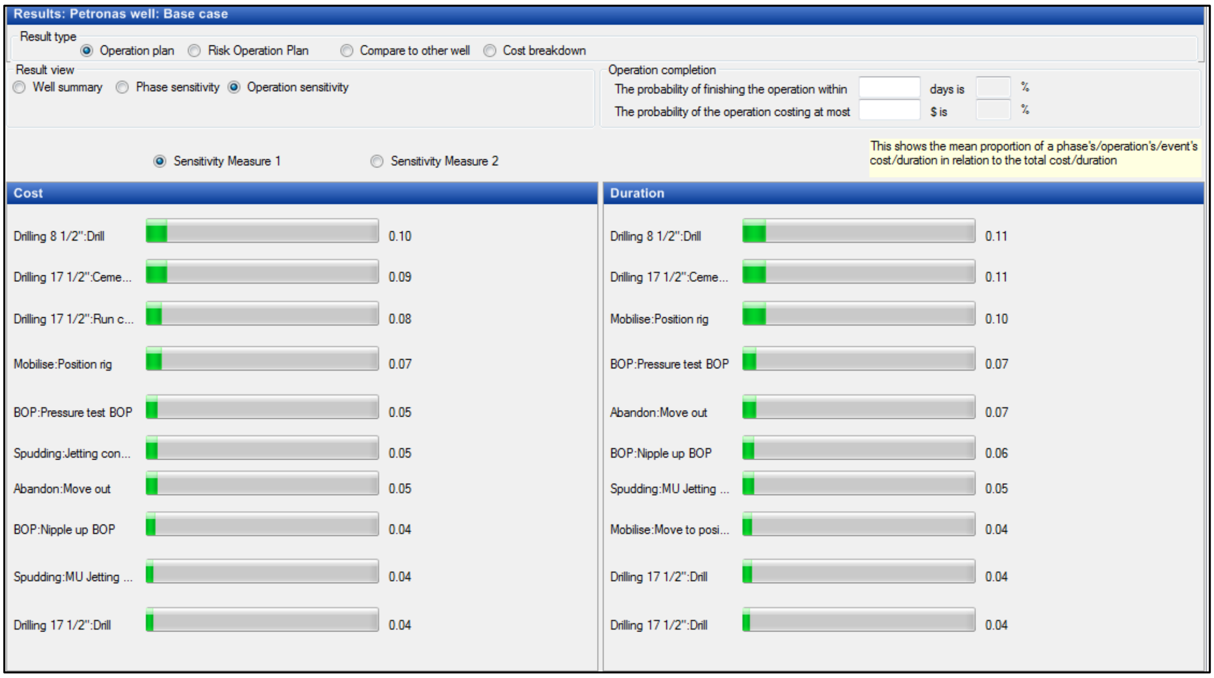

Figure 33: Result of operation sensitivity

The total cost of the standard operation plan can be broken down into different cost codes and displayed in the cost breakdown panel. The user can choose if either the cost of the total well or the selected phase will be shown.

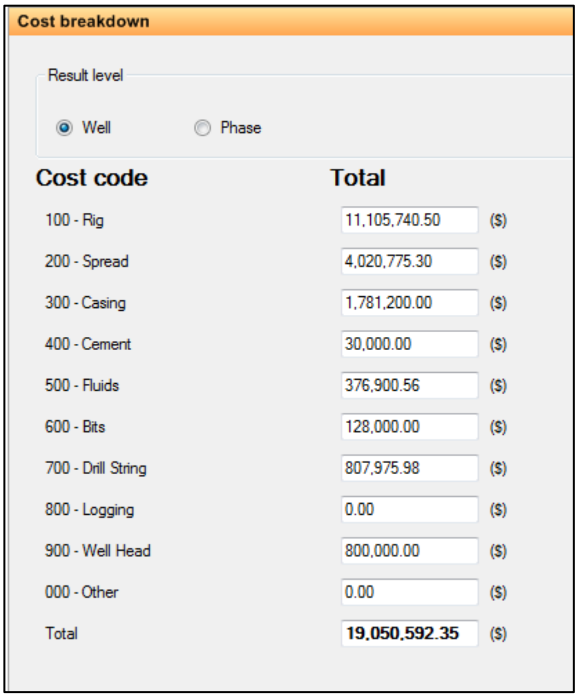

Figure 34: Result view of cost breakdown

6. Simulations and Discussions of an Example Well using Risk€

6.1 Background

The base case scenario to be presented here is a hydrocarbon well inspired by one of Statoil drilling programs released for teaching through the Academia Program. The well conditions and general information used in the simulation are mostly based on this activity program. In spite of that, the numbers related to cost and duration expected for each sub operation are estimated based on various sources. Hence, this should be considered as an example of cost and duration of an operation.

The well is to be drilled in an offshore area of the Norwegian continental shelf by semi-submersible rig with 25m air gap from mean sea level. This well was not drilled in deep water area and the water depth is 375m. The 36” conductor will be run by drilling top hole section. For referencing purpose, the base case well is assigned the name as well YES-01.

Well Name	YES-01
Area	Offshore, NCS
Objective	Oil Production
Rig Type	Semi-submersible
Air Gap	25 m
Water Depth	375 m

Table 4: Well general information

According to the drilling activity plan, this well will be drilled as pilot hole prior to plugging back the 6” pilot section and performing sidetrack below 7” liner shoe.

Planned operations for this well are to drill and run casing in 36”, 26”, 12 ¼” and 8 ½” section. In the 8 ½” section, there is a high risk for differential sticking due to depleted formation. Hence, it was chosen to isolate this zone by running a 7” liner and cementing this before continuing with a 6” hole. The 6” pilot section will be drilled to TD at +/- 3,980 mMD RT. There are 3 main purposes of drilling a pilot section which are reducing the stratigraphic depth uncertainty, evaluation of OWC and oil saturation and evaluation of reservoir properties. After that, the 6” pilot will be plugged back and cemented to inside 7” liner. A 6” oil producer will be kick off below 7" liner shoe and geo-steered to TD at +/- 4,083 mMD RT. The information regarding each section is presented in table 5 .

Section (in)	Section depth (mMD)	Suspension Depth (mMD)	Casing shoe (mMD)	Casing OD (in)	Casing ID (in)
36.00	460	400	457	30.000	29.000
26.00	1352	400	1347	20.000	19.000
12.25	3161	400	3155	9.625	8.844
8.50	3408	3055	3408	7.000	6.188
6.00(pilot)	3980	-	-	-	-
6.00(producer)	4083	-	-	-	-

Table 5: Section details

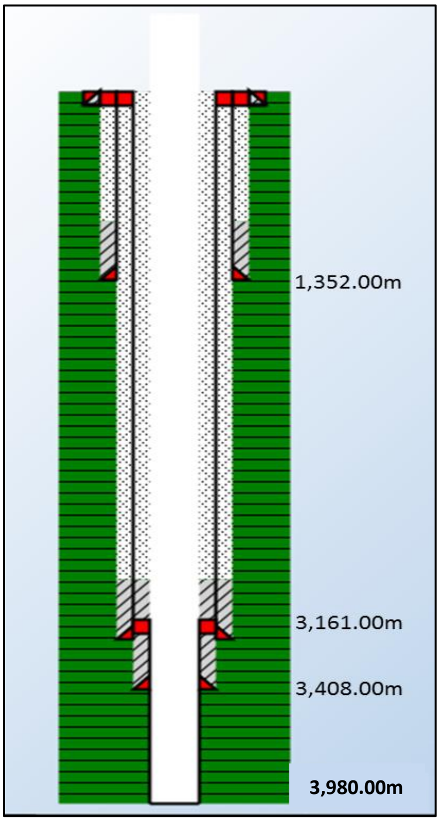

Figure 35: Wellbore schematic of pilot hole

Figure 35 shows the wellbore schematic of the pilot hole for the well YES-01. The numbers shown in the figure are section TD of 26", 12 ¼", 8 ½" and 6" pilot section respectively.

The operation plan of this well is to divide drilling activities into steps as shown below.

Mobilization

Move to position
Position rig
Anchoring

Spudding

- MU BHA
- RIH
- Drill top hole
- POOH
- Break BHA
- Run conductor
- Cement
- POOH

Drilling 26" Section

- MU BHA
- RIH
- Drill
- Circulate
- POOH
- Break BHA
- Run casing
- Cement
- POOH

BOP

- Nipple up BOP
- Run BOP and riser
- Pressure test BOP

Drilling 12 1/4" section

- MU BHA
- RIH
- Drill new formation
- Circulate
- LOT
- Drill
- Circulate
- POOH
- Change bit
- RIH
- Drill
- Circulate
- POOH
- Break BHA
- Run Casing
- Cement

	POOH
BOP	
	Pressure test BOP
Drilling 8 1/2" section	
	MU BHA
	RIH
	Drill new formation
	Circulate
	LOT
	Drill
	Circulate
	POOH
	Break BHA
	Run casing
	Cement
	POOH
BOP	
	Pressure test BOP
Drilling 6" pilot section	
	MU BHA
	RIH
	Drill
	Circulate
	POOH
	Break BHA
Plug back pilot hole	
	RIH with 3 ½” cement stinger
	Plug back pilot hole to inside 7” liner
	POOH 3 ½” cement stinger
Sidetracking	
	MU BHA
	RIH
	Drill
	Circulate
	POOH
	Break BHA

6.2 Input Data

The data used as an input for MCS is collected from various sources; such as literatures, example cases, expert comments, personal experiences, etc.

The numbers for input parameters in the base case are shown in the table below.

Mobilization Phase				
Parameter	**Distribution Type**	**Minimum**	**Peak/Mean**	**Maximum**
Velocity(nmi/hr)	Triangle	1	3	5
Position rig duration(hr)	Triangle	15	30	45
Anchoring duration(hr)	Uniform	24	-	30
Rig rate($/day)	Uniform	500,000	-	850,000
Fixed Cost($/day)	Single	-	13,000	-
Spread rate($/day)	Triangle	18,000	23,000	27,000
Spudding				
Parameter	**Distribution Type**	**Minimum**	**Peak/Mean**	**Maximum**
MU BHA(hr)	Uniform	2	-	3
Break BHA(hr)	Uniform	1	-	2
Tripping speed(m/hr)	Uniform	300	-	500
ROP(m/hr)	Triangle	5	10	15
Bit cost($) - 36" section	Triangle	60,000	75000	90,000
Accessories cost($)	Uniform	8,000	-	12,000
Conductor cost($/m)	Triangle	810	1,200	1,500
Running speed(m/hr)	Uniform	50	-	100
Cementing duration(hr)	Uniform	5	-	9
Cement volume(m^3)	Single	37	37	37
BOP Installation				
Parameter	**Distribution Type**	**Minimum**	**Peak/Mean**	**Maximum**
Nipple up BOP(hr)	Triangle	26	32	35
Pressure test BOP(hr)	Uniform	5	-	7
Drilling				
Parameter	**Distribution Type**	**Minimum**	**Peak/Mean**	**Maximum**
MU BHA(hr)	Uniform	2	-	3
Break BHA(hr)	Uniform	1	-	2
Tripping speed(m/hr)	Uniform	300	-	500
ROP(m/hr) - 26" section	Triangle	5	20	35
ROP(m/hr) - 12 1/4" section	Triangle	10	25	40
ROP(m/hr) - 8 1/2" section	Triangle	10	20	30
ROP(m/hr) - 6" section(pilot)	Triangle	5	15	25
ROP(m/hr) - 6" section(sidetrack)	Triangle	5	15	25
Bit cost($) - 26" section	Uniform	30,000	-	50,000
Bit cost($) - 12 1/4" section	Triangle	22,000	29,000	35,000
Bit cost($) - 8 1/2" section	Triangle	19,000	21,000	23,000
Bit cost($) - 6" section(pilot)	Triangle	16,000	19,000	22,000
Bit cost($) - 6" section(sidetrack)	Triangle	16,000	19,000	22,000

Parameter	Distribution Type	Minimum	Peak/Mean	Maximum
Circulation time(hr)	Uniform	4	-	7
Fluid cost($/m^3)	Uniform	1000	-	2000
Casing cost($/hr) - 26" section	Triangle	300	365	420
Casing cost($/hr) - 12 1/4" section	Triangle	130	150	170
Casing cost($/hr) - 8 1/2" section	Triangle	90	105	120
Casing run speed(m/hr)	Single	300	300	300
Cementing duration(hr) - 26" section	Triangle	7	9	11
Cementing duration(hr) - 12 1/4" section	Triangle	10	12	14
Cementing duration(hr) - 8 1/2" section	Triangle	13	15	18
Cement volume(m^3) - 26" section	Single	132.44	132.44	132.44
Cement volume(m^3) - 12 1/4" section	Single	11.64	11.64	11.64
Cement volume(m^3) - 8 1/2" section	Single	5.30	5.30	5.30
Cement slurry cost($/m^3)	Single	2000	2000	2000
Leak off test duration(hr)	Uniform	0.5	-	1.5
Rig rate($/day)	Uniform	500,000	-	850,000
Drillstring/BHA cost($/day)	Normal	-	50,000	-
Fixed Cost($/day)	Single	60,000	60,000	60,000
Spread rate($/day)	Triangle	60,000	80,000	100,000
Support Cost($/day)	Uniform	50,000	-	80,000
Wellhead cost($)	Single	800,000	800,000	800,000

Table 6: Summary of input parameters

6.3 Results from Standard Operation Plan

Standard operation plan is referred to the well construction processes where all the activities can be performed according to the planned schedule, without any interruptions from undesirable events.

After all the input parameters have been filled in, user can choose either 10,000 or 100,000 iterations to be used for the Monte Carlo simulation. In this case, 10,000 iterations are used for the simulation. The results from the simulation will be presented in various forms.

6.3.1 Deterministic View

An overall result for an operation plan can be displayed in a deterministic view. The results are based on expected values in the probability distributions that are given for the different input values. Simulation is not needed to display this type of result.

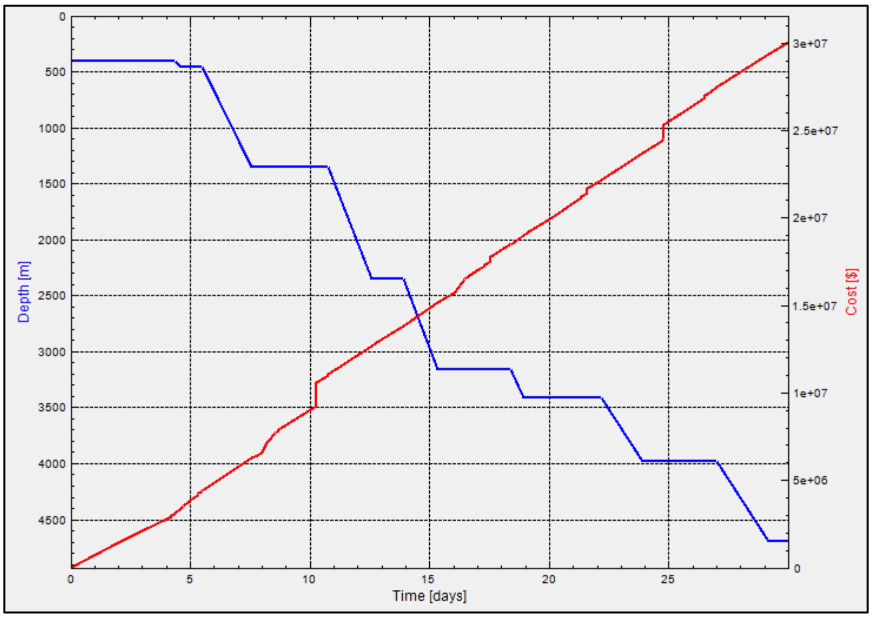

Figure 36: Deterministic view from the result of the standard operation plan

From figure 36, the time-depth curve (the blue line) demonstrates that it takes 29.09 days to reach the TD of the well. By including circulation, tripping and breaking BHA time, it requires about 29.97 days of well duration. The red line shows the construction cost as the well is drilled deeper. To finish drilling this well, a budget around 30.01 million USD is required, according to the deterministic well cost estimation.

6.3.2 Probabilistic View

After performing the Monte Carlo simulation, the probabilistic results can be shown.

Well Summary

The well summary view displays the time – depth curve in the form of different percentiles. At the bottom part of the display, it shows the histograms for total cost and duration of the well construction processes. The expected value, standard deviation as well as possible range of outcome are also presented here.

Figure 37: Well summary result from standard operation plan

From figure 37, the expected duration to drill this well is 29.78 days with the standard deviation of 1.58 days. An expected cost of this well is 29.90 million USD with the standard operation of 1.77 million USD. The well could be completed within 25.75 days the soonest and 37.33 days the latest. The budget required to drill this well could range from 24.53 – 37.51 million USD. The probability that the operation will be completed within 29.78 days is 54.4% and the probability that the operation will cost at most 29.90 million USD is 53.1%.

Method	Deterministic Approach	Probabilistic Approach
Expected Duration	28.71 days	29.78 days
Range of Possible Duration	N/A	25.75 - 37.33 days
Expected Cost	30.01 million USD	29.90 million USD
Range of Expected Cost	N/A	24.53 - 37.51 million USD

Table 7: Results comparison between deterministic and probabilistic approach

From table 7, the expected value of cost and duration required for well operation from both approaches are not the same, but they do not have huge differences. However, the deterministic method is not able to provide the range of possible outcome as well as the probability of completing the well within the expected time period and budget.

Phase Sensitivity

This view will display the contribution of each phase to the estimated results. Each phase's cost and duration is displayed as proportions of the total cost and duration for the operation plan.

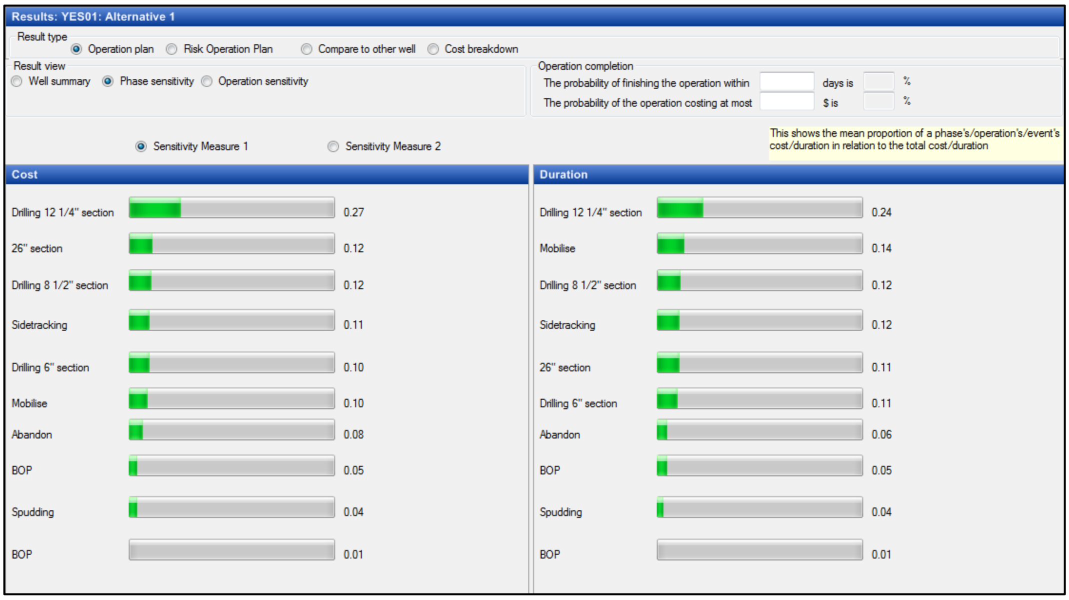

Figure 38: Phase sensitivity from standard operatoin plan

The phase sensitivity analysis shows that drilling 12 ¼" section is the most sensitive phase compared to the other phases. It contributes for 27% of the total cost and 24% of the total duration. Drilling phases for several sections as well as mobilization phase also contribute significantly to the total estimated cost and duration. The differences between these phases are not apparent. One can notice from figure 38 that the mobilization phase makes the second largest contribution to the total duration but the 6^{th} largest contribution to the well total cost. This could be based on the fact that during the time of rig mobilization, the spread rate cost is considerably lower than other phases in this example case.

Operation Sensitivity

The operation sensitivity displays each operation's cost and duration as proportions of the total cost and duration.

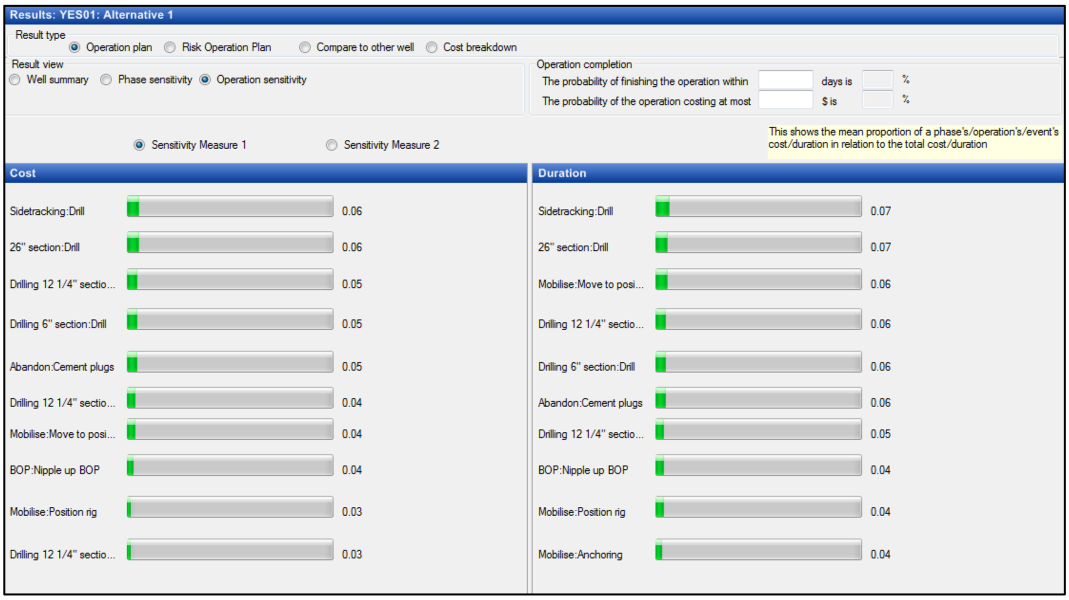

Figure 39: Operation sensitivity from standard operation plan

When looking at the operation level, drilling sub operations are the most dominating factors compared to other sub operations. Both cost and duration sensitivity analysis demonstrate that drilling the sidetrack hole section has the largest effect on the results. Cost and duration spent on drilling other sections also have significant impact and slight difference can be observed among various sections.

Cost Breakdown

The cost breakdown result type shows the expected total cost, broken into predefined cost categories (cost codes) for the standard operation plan.

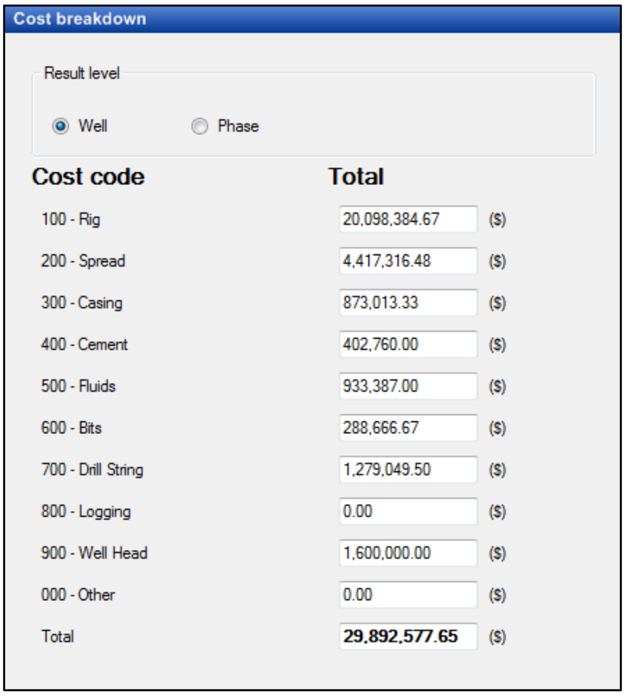

Figure 40: Cost Breakdown of standard operation plan

If we break down the well total cost into its elements, it is obvious that the rig rental cost has the most important contribution to the total cost. It is responsible for 20.10 million USD from 29.89 million USD of total well cost or more than 67% of the well total cost. The second largest contribution is the spread rate cost which highly depends on the total well duration as well. The spread rate represents 14.78% of the well total cost. These 2 cost codes are responsible for 82.01% of the total cost. Both of them are time-related cost. Thus, we can conclude that time spent on well operations is the most crucial cost driving parameter.

6.4 Detailed Sensitivity Analysis

According to the tornado charts of phase sensitivity and operation sensitivity of the base case result (figure 38 and figure 39), time and cost spent on drilling and mobilization has the largest contributions on the total well cost and duration. Within the drilling phase, time spent on drilling is the most influential parameter while moving rig to location has the greatest impact on mobilization phase. As a consequence, 2 input variables, which are ROP and rig moving velocity, have been selected for detailed analysis here. The result of the detailed sensitivity analysis could suggest how an exact knowledge of these parameters would affect the reduction in uncertainty of the total cost and duration. It could also recommend if budget should be spent on further data collection.

6.4.1 Detailed Analysis of ROP

Drilling the formation takes much more time than tripping, circulation, casing running and cementing. Thus, further study has been performed to analyse the effect of various ROP inputs on the uncertainty and expected value of the prediction.

Uncertainty Analysis

In order to analyse the uncertainty of the results, the standard deviation of well cost and duration obtained by using different distribution types for ROP will be plotted against the standard deviation obtained while using single value input for the ROP. The distribution types to be studied here are the uniform distribution, the triangle distribution and the single distribution. Each distribution type will be assigned for every section. The results of the uniform distribution mean that the uniform distribution is used as an input distribution for ROP in every section. Same logic goes to the triangle distribution and the single distribution. The ROP input values used in this study are shown in the table below.

Triangle Distribution			
Section(in)	ROP (m/hr)		
	Minimum	Most Likely	Maximum
26.00	5	20	35
12.25	10	25	40
8.50	10	20	30
6.00(pilot)	5	15	25
6(ST)	5	15	25

Uniform Distribution			
Section(in)	ROP (m/hr)		
	Minimum	Most Likely	Maximum
26.00	5	-	35
12.25	10	-	40
8.50	10	-	30
6.00(pilot)	5	-	25
6(ST)	5	-	25
Single Distribution			
Section(in)	ROP (m/hr)		
	Minimum	Most Likely	Maximum
26.00	-	20	-
12.25	-	25	-
8.50	-	20	-
6.00(pilot)	-	15	-
6(ST)	-	15	-

Table 8: ROP input values for each distribution type.

Well Duration Analysis: The effect of each distribution type on the uncertainties of well duration is shown by the standard deviation of the predicted duration.

Distribution Type	Duration SD (days)
Triangle	1.60
Uniform	2.43
Single	0.73

Table 9: Well duration SD for each ROP distribution type

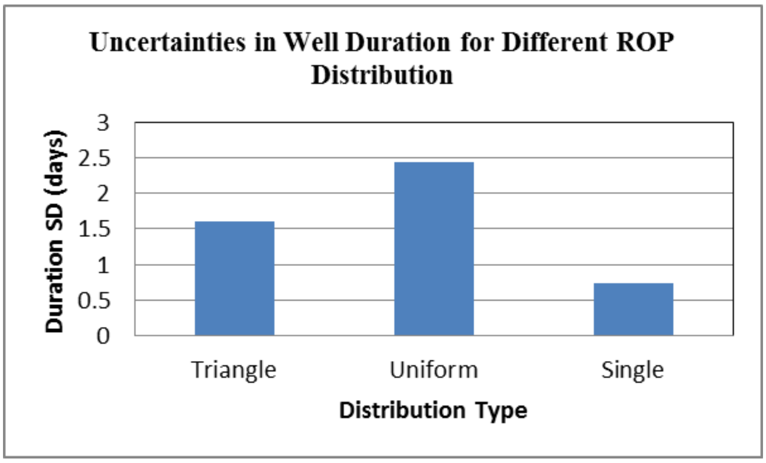

Figure 41: Uncertainties in well duration for different ROP distribution

From table 9 and figure 41, it is obvious that the single distribution ROP gives the results with the least uncertainties in well duration while the uniform distribution gives the results with the largest uncertainties. The difference between each distribution type is pretty apparent. The well duration standard deviation from the uniform distribution and the triangle distribution are 3.3 and 2.2 times higher than the single distribution.

Well Cost Analysis: Similar to the well duration, in this case, the SD of estimated well cost will be compared for each distribution type.

Distribution Type	Cost SD(million USD)
Triangle	1.79
Uniform	2.41
Single	1.22

Table 10: Well cost SD for each ROP distribution type

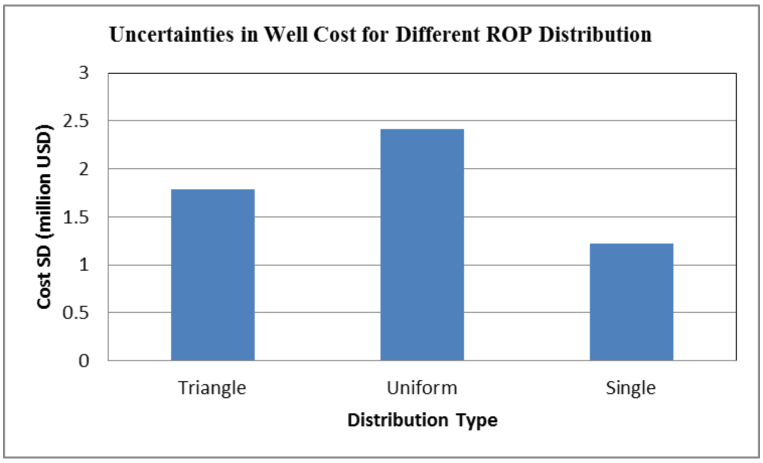

Figure 42: Uncertainties in well cost for different ROP distribution

The uncertainties in the well cost have a matching results with the uncertainties in well duration. From table 10 and figure 42, we can notice that the single distribution and the uniform distribution also give the lowest and the highest uncertainties result respectively. Nevertheless, the difference in well cost uncertainties is smaller than the well duration uncertainties. The standard deviation of the well cost from the uniform distribution and the triangle distribution are 2.0 and 1.5 times higher than the single distribution.

From the uncertainties analysis of the well cost and duration, we can conclude that better knowledge on expected range of ROP could greatly reduce the uncertainties of the results.

Value Analysis

In this section, the expected value of the results will be analysed by varying the ROP. In every section, the ROP will be set as single distribution. 3 more cases will be simulated and compared with the triangle distribution based case. These 3 cases are when the ROP is at its minimum, at its most likely and at its maximum. The inputs ROP for each section are shown in the table below. "Minimum" mentioned in the table and figure below implies that the ROP input value in every section is at its minimum using the single distribution. Same logic is used for the "Most Likely" and "Maximum" cases.

	ROP (m/hr)				
Section (in)	**26.00**	**12.25**	**8.50**	**6.00(pilot)**	**6.00(ST)**
Minimum	5	10	10	5	5
Most Likely	20	25	20	15	15
Maximum	35	40	30	25	25

Table 11: ROP inputs for value analysis

Well Duration Analysis

ROP(m/hr)	Expected Duration (days)
Minimum	46.93
Most Likely	29.16
Maximum	25.64
Base Case	29.90

Table 12: Expected duration from different ROP value

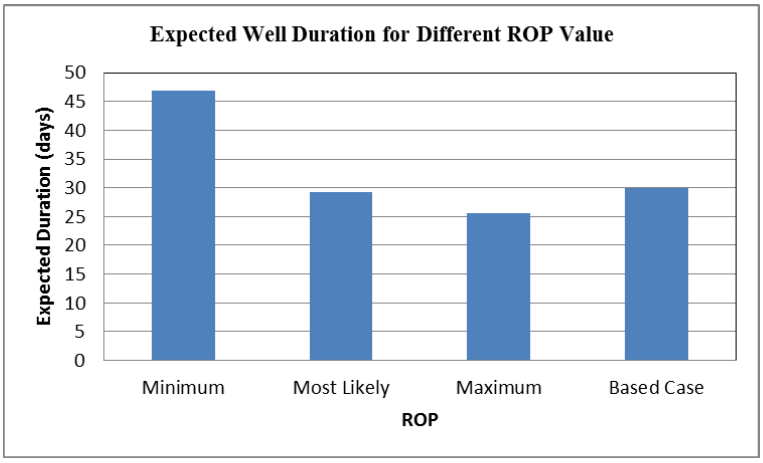

Figure 43: Expected well duration for different ROP value

In the uncertainties analysis section, the results from the triangle distribution and the single distribution have a large difference in their standard deviation of duration. However, from table 12 and figure 43, we can see that the difference between the expected well duration from the "Most Likely" case (single distribution) and the "Base Case" (triangle distribution) is almost negligible. The "Most Likely" case is only 0.82 day faster than the "Base Case". On the other hand, the change in ROP from "Base Case" to "Minimum" and "Maximum" case has a noticeable effect on the well duration. If the ROP of every section is at its minimum, the well can be expected to be delayed more than 50% compared to its initial prediction.

Well Cost Analysis

ROP(m/hr)	Expected Cost(million USD)
Minimum	44.82
Most Likely	29.36
Maximum	26.31
Base Case	30.06

Table 13: Expected well cost from different ROP Value

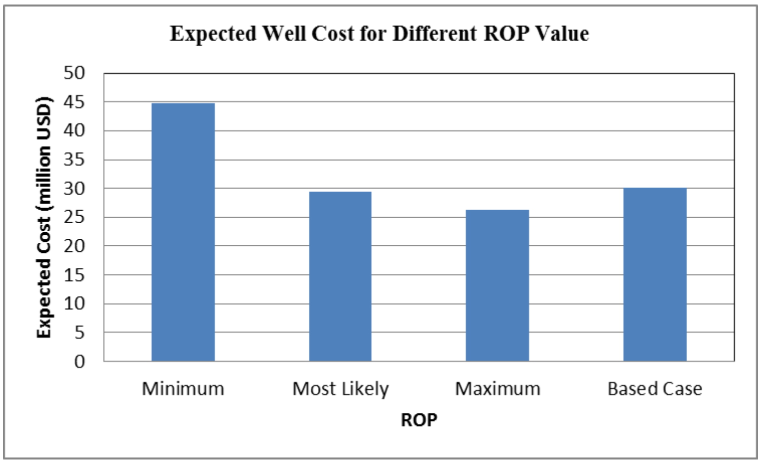

Figure 44: Expected well cost for different ROP value

Similar to the well duration, the expected cost from the "Most Likely" case and the "Base Case" are almost the same. The "Most Likely" cost is 0.7 million USD lower than the "Base Case". When the ROP is at its minimum, it causes a long delay in the well duration. Thus, the expected cost is also increased significantly. At the same time, when the ROP is at its maximum, the reduction in well cost is detectable but the effect is not as large as the minimum case.

6.4.2 Detailed Analysis of Rig Mobilization Velocity

As presented in the phase sensitivity tornado chart, figure 38, mobilization phase is the 2nd most influential phase on the well duration. Apart from that, the article "Who moved my rig?" published in Oil & Gas Financial Journal published on December 1st, 2011 presented a study on this which was performed by Alvarez and Marsal 2009. The summary of the study showed that rig mobilization is responsible for 25% of the total rig time. It represents the second biggest contribution among all the drilling rig activities. The largest contribution is time spent on drilling and casing.

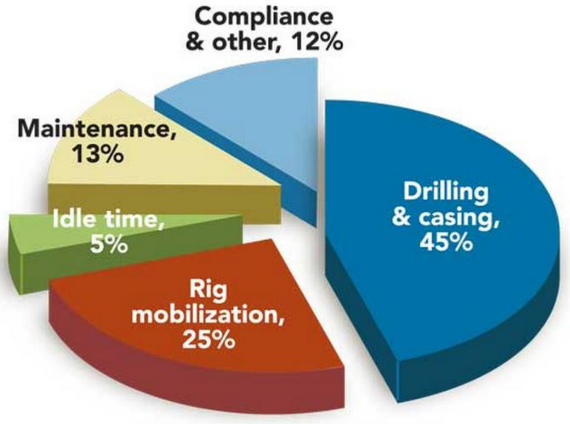

Figure 45: Summary of typical drilling rig time distribution – Source: [3]

When we look into the operation sensitivity of the base case, figure 39, time spent on moving rig to location is the most important sub operation for the mobilization phase. The uncertainties and value of this sub operation will be studied here.

Uncertainties Analysis

The uncertainty of the results will be analysed by plotting the standard deviation of well cost and duration obtained by using different distribution types for rig moving velocity against the standard deviation obtained while using single value input for the velocity. The distribution types to be studied here are the uniform distribution, the triangle distribution and the single distribution. The input values of each distribution type are shown in the table below.

Distribution	Rig Moving Velocity (nmi/hr)		
	Minimum	Most Likely	Maximum
Triangle	1	3	5
Uniform	1	-	5
Single	-	3	-

Table 14: Rig moving velocity inputs for each distribution type

Well Duration Analysis

Distribution Type	Duration SD (days)
Triangle	1.59
Uniform	1.76
Single	1.48

Table 15: Well duration SD for each velocity distribution type

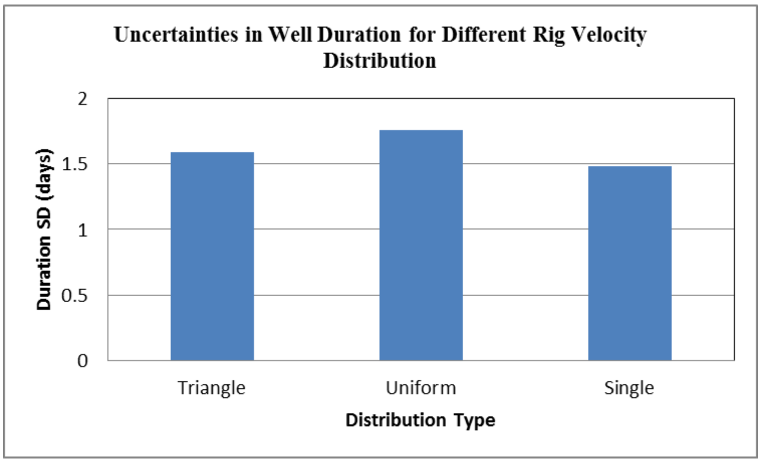

Figure 46: Uncertainties in well duration for different rig velocity distribution type

We can see from table 15 and figure 46 that the uniform distribution has the highest uncertainties among all 3 distribution types. In this case, the differences between each distribution type are not so large compared to the effect of ROP distribution type. The duration SD from the triangle distribution and the uniform distribution are only 1.07 and 1.19 times higher than the single distribution.

Well Cost Analysis

Distribution Type	Cost SD(million USD)
Triangle	1.78
Uniform	1.82
Single	1.75

Table 16: Well cost SD for each velocity distribution type

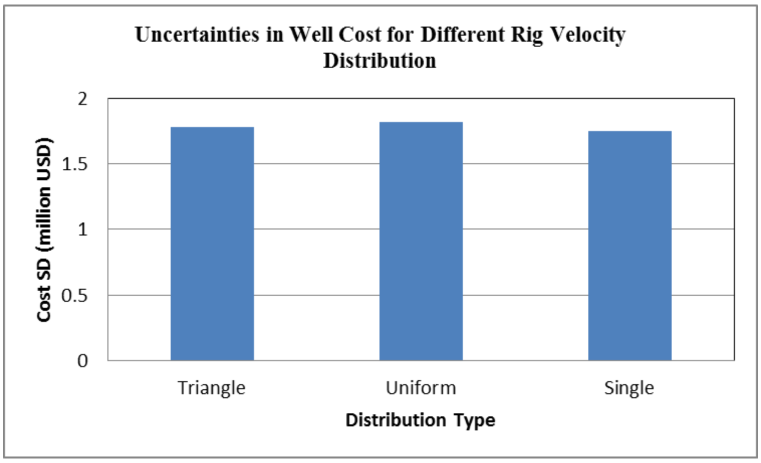

Figure 47: Uncertainties in well cost for different rig velocity distribution type

Figure 47 shows that the results from all 3 distribution types are pretty close to each other. Even though the uniform distribution and the single distribution still have the highest and the lowest uncertainties, the difference between each distribution type is insignificant.

The results from the well duration and well cost analysis demonstrate that the distribution type of the rig moving velocity has a noticeable effect on the uncertainties of the well duration but less significant impact on the well cost.

Value Analysis

In order to see the effect of the rig velocity on the expected value, the rig velocity input will be varied using the single distribution. The velocity to be studied ranges from 1 nmi/hr to 9 nmi/hr.

Well Duration Analysis

Rig Velocity(nmi/hr)	Expected Duration (days)
1	33.15
3	29.82
5	29.14
7	28.87
9	28.71

Table 17: Expected duration for each rig velocity

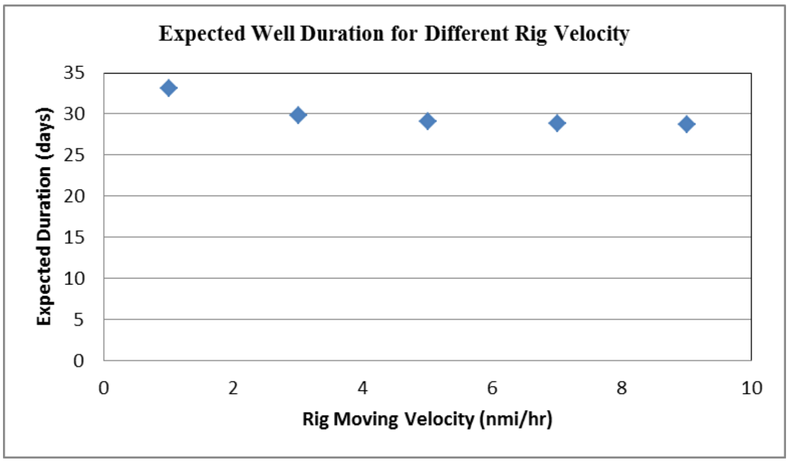

Figure 48: Expected well duration for different rig velocity

From figure 48, the results from using 3 nmi/hr to 9 nmi/hr are pretty close to each other. The largest difference of the expected duration is 1.11 days when comparing using 3 nmi/hr and 9 nmi/hr rig velocity. Nevertheless, when the rig velocity is set as 1 nmi/hr, the expected duration is obviously longer than other cases, 3.33 days extended compared to using 3 nmi/hr.

Well Cost Analysis

Rig Moving Velocity(nmi/hr)	Expected Cost(million USD)
1	32.25
3	29.95
5	29.48
7	29.31
9	29.22

Table 18: Expected cost for each rig velocity

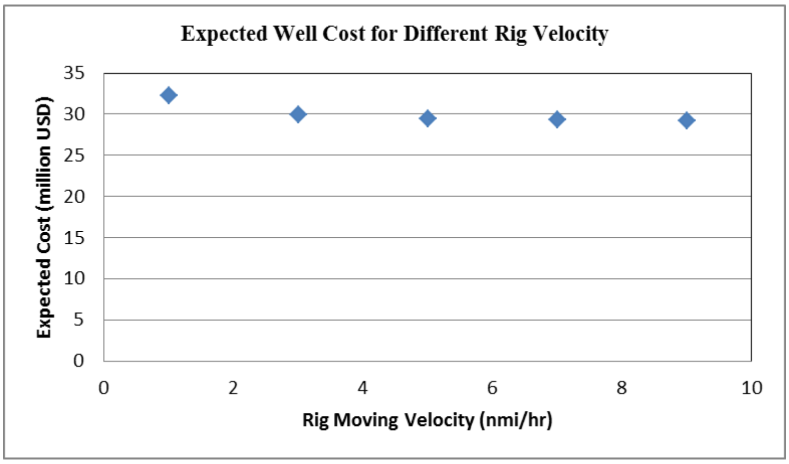

Figure 49: Expected well cost for different rig velocities

Figure 49 shows that the result agrees with the well duration analysis. The velocity of the rig move does not have a huge effect on the expected well cost except when the velocity is extremely slow, 1 nmi/hr in this case. The expected well cost if the rig moves with 3 nmi/hr is 0.73 million USD higher than if the rig moves with 9 nmi/hr while the difference between 3 nmi/hr case and 1 nmi/hr case is 2.3 million USD.

6.5 Results from Risked Operation Plan

6.5.1 Input of Risk Events into the Well Model

In the previous section, the results from the standard operation plan have been discussed. Now the risked operation plan will be considered by including undesirable events into the well model. Some example of risks available in the simulator, both for the well level and the phase level, has been identified in chapter 5. In spite of that, 4 main risk events have been selected to be studied here which are Wait on Weather (WOW), Kick, BHA failure and Stuck pipe.

Wait on Weather (WOW) – It is one of the most common causes of operation delays especially in the North Sea area. Some operators have included an extra duration of 10% - 15% of the standard operation plan for WOW issue while planning the well. According to the result of the standard operation plan, the expected duration is 29.78 days. Thus, 10% of this duration, approximately 3 days, will be used as an input for WOW. A.J. Adams[10] has suggested that the Weibull distribution should be used for WOW event.

Kick/ Well Control Event – The probability of kick event can vary considerably, depending on the activity and the geological condition. As it is mentioned in the background of the base case well, this example well is drilled in an offshore area of the North Sea. J.D. Dobson[44] has presented some statistical studies regarding the kick events according to the geological basin and the rig type. When the kicks are analysed by rig type, the kicks happened least frequently on the wells drilled by the semi-submersible rig (68 out of 333 kick events). Based on 2,757 wells drilled in several areas of the North Sea, there are 332 kick events. As a consequence, a kick probability of 12% will be used in this simulation.

BHA Failure – In case of BHA failure, the extra duration required depends significantly on the depth of failure while the tripping speed is almost the same for every section. Hence, each hole section would have different range of extra duration input.

Stuck Pipe – J.A. Howard[45] has performed a study about stuck pipe events using a database with data from more than 1,000 wells drilled in the Gulf of Mexico and the North Sea. Statistically, the data showed that one of three wells drilled in the Gulf of Mexico and the North Sea has experienced stuck pipe problems. Thus, the input probability of the event occurrence will be set as 33%. In this case, the simulation is performed with the assumption that the pipe can be released and there's no extra cost due to having a BHA lost in the hole.

The table below shows the probability of occurrence and the extra duration of each risk event.

Event	Distribution Type	Probability(%)	Extra Duration(hr)
Wait on Weather (WOW)	Weibull	90	Scale = 72 hr, Shape = 1
Kick	Triangle	12	Min = 6 hr, Peak = 12 hr, Max = 96 hr
BHA Failure 26.00" section	Uniform	20	Min = 8 hr, Max = 14 hr
BHA Failure 12.25" section	Uniform	20	Min = 16 hr, Max = 26 hr
BHA Failure 8.50" section	Uniform	20	Min = 17 hr, Max = 28 hr
BHA Failure 6.00" section (pilot)	Uniform	20	Min = 19 hr, Max = 32 hr
BHA Failure 6.00" section(ST)	Uniform	20	Min = 19 hr, Max = 32 hr
Stuck Pipe	Uniform	33	Min = 4 hr, Max = 72 hr

Table 19: Input parameters for risk events

In table 19, WOW is a risk event in the well level while the rests are the events on phase level.

6.5.2 Results of Risked Operation Plan

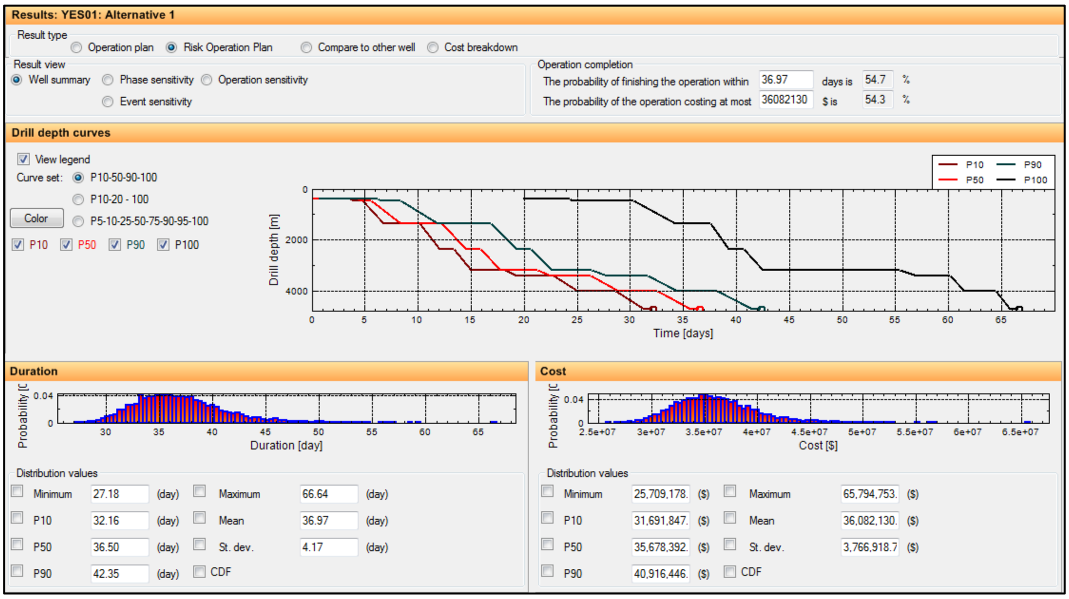

Figure 50: Well summary results of risked operatoin plan

Figure 50 presents the results of the risk operation plan. When undesirable events are included in the well model, the expected well duration is 36.97 days with 4.17 days standard deviation. The duration can last from 27.18 days to 66.64 days. The expected well cost is 36.08 million USD with 3.77 million USD standard deviation. The range of possible well cost is 25.71 million USD to 65.79 million USD. The probability of finishing the well within the expected duration and budget is 54.7% and 54.3% respectively.

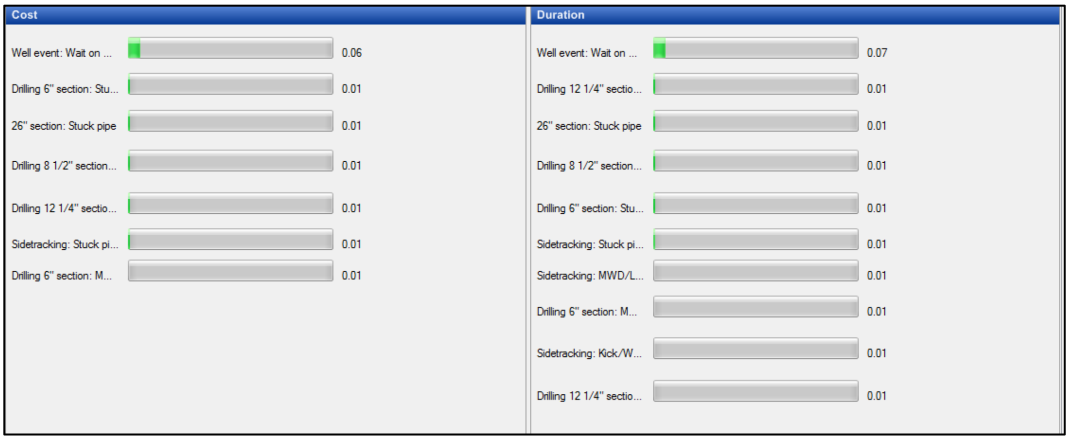

Figure 51: Events sensitivity analysis

As the events sensitivity analysis is performed, waiting on weather (WOW) shows the greatest effect on the well cost and duration. Its impact is apparently higher than any other risk events included in the model as it represents 6% of the total cost and 7% of the total duration.

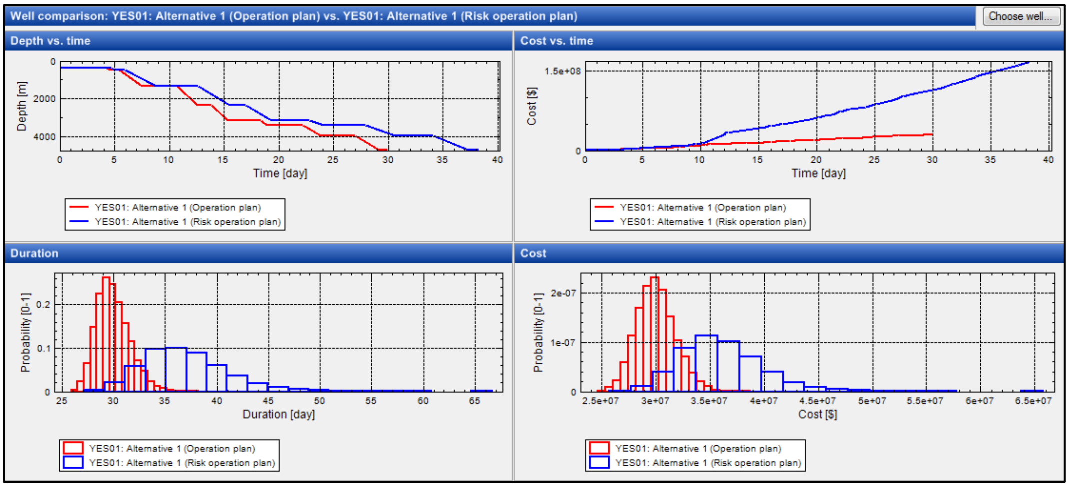

Figure 52: Results comparison between standard operation plan and risk operation plan

6.5.3 Comparison of Results between Standard Operation Plan and Risk Operation Plan

Well Duration(days)		
	Standard Operation Plan	**Risk Operation Plan**
Minimum	25.89	27.18
Mean	29.98	36.97
Maximum	38.23	66.64
SD	1.59	4.17
Well Cost(million USD)		
	Standard Operation Plan	**Risk Operation Plan**
Minimum	24.66	25.71
Mean	30.06	36.08
Maximum	38.74	65.79
SD	1.78	3.77

Table 20: Comparison of standard operation plan and risk operation plan

From figure 52 and table 20, the results of both standard operation plan and risk operation plan have been compared. Figure 52 shows that histograms of well cost and duration from the risk operation plan skewed to the right with much longer tail, compared to the standard operation plan. From table 20, one can notice that the minimum estimated well cost and duration from both plans are pretty close to each other. At the same time, the expected duration and the expected cost of the risk operation plan is higher than the standard operation plan i.e. 23.3% and 20.0% respectively. The most noticeable changes are the maximum possible outcomes where the risk operation plan gives much higher values. These drive the standard deviation of the risk operation plan to be 2.62 and 2.12 times higher than the standard operation plan for the estimated duration and cost respectively.

In the next section, the effect of each undesirable event on the total cost and duration will be studied.

6.5.4 Detailed Sensitivity Analysis of Undesirable Events

Figure 51 shows the sensitivity analysis of all the undesirable events included in the well model. In this section, detailed sensitivity analysis of these events will be performed by setting the probability of occurrence, event by event, to be zero. After that, the estimated results will be compared with the standard operation plan and the normal risk operation plan. The figures below show the results of risk operation plan without WOW, kick incident, BHA failure incident and stuck pipe incident respectively.

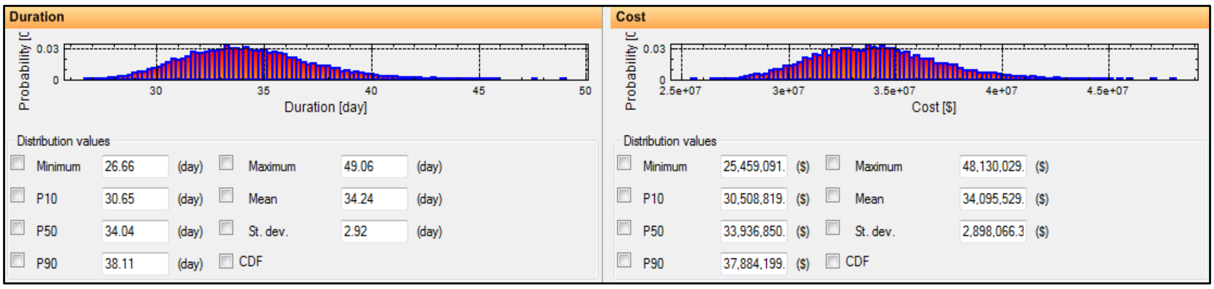

Figure 53: Result of risk operation plan without WOW event

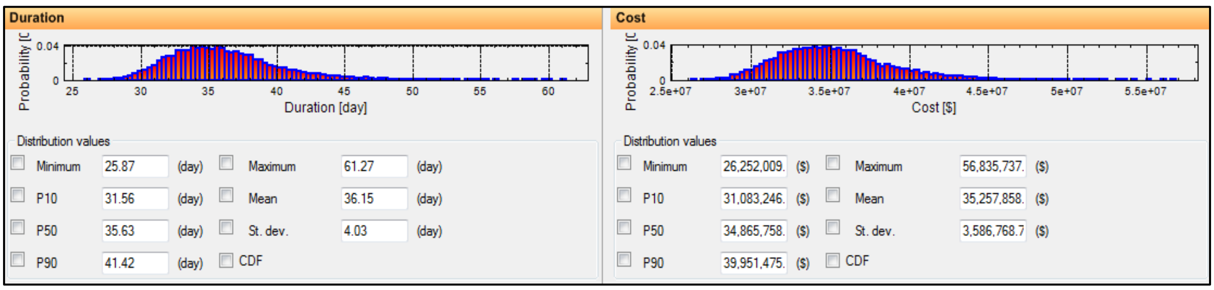

Figure 54: Result of risk operation plan without kick event

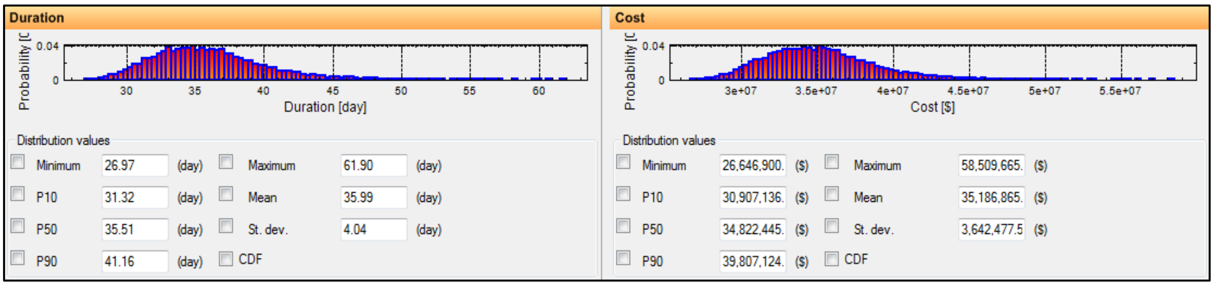

Figure 55: Result of risk operation plan without BHA failure event

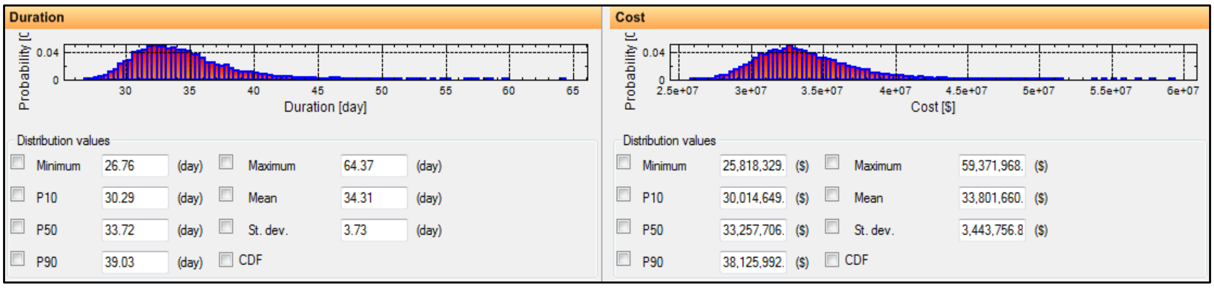

Figure 56: Result of risk operation plan without stuck pipe event

Uncertainties Analysis

Well Duration Analysis

Operation Plan	Duration SD (days)
Standard	1.59
Risk	4.17
Risk W/O WOW	2.92
Risk W/O Kick	4.03
Risk W/O BHA failure	4.04
Risk W/O Stuck pipe	3.73

Table 21: Well duration SD for different operation plan

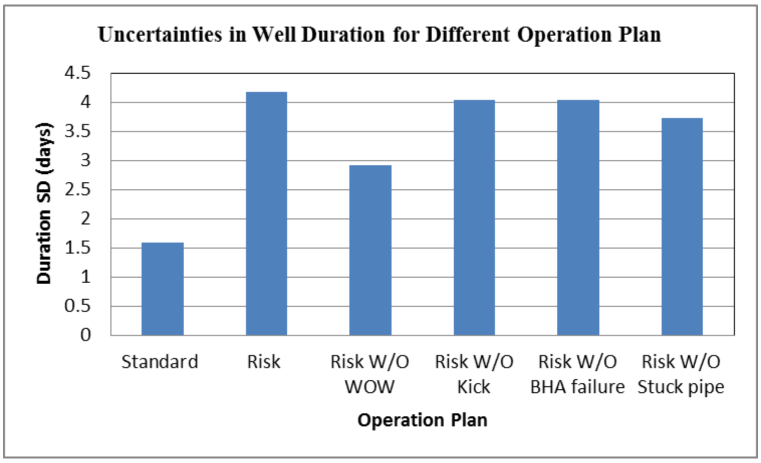

Figure 57: Uncertainties in well duration for different operation plan

From table 21 and figure 57, the SD of standard operation plan is apparently lower than the SD of other risk operation plans. When each risk event is excluded from the model one at a time, the duration SD of each scenario is plotted against other cases. One can notice that when WOW is excluded from the model, the duration SD reduces significantly from the normal risk operation plan. The reasons behind could be the Weibull distribution used for WOW event. The long tail of this distribution may drive the maximum duration to be much longer. Thus, the well model without WOW event has a greatly reduction in duration uncertainty compare to other risk operation plan. While the uncertainties of the risk operation plan without kick incident and without BHA failure incident are relatively close to the normal risk operation plan, the risk operation plan without stuck pipe incident shows slightly lower uncertainty.

Well Cost Analysis

Operation Plan	Cost SD (million USD)
Standard	1.78
Risk	3.77
Risk W/O WOW	2.90
Risk W/O Kick	3.59
Risk W/O BHA failure	3.64
Risk W/O Stuck pipe	3.44

Table 22: Well cost SD for different operation plan

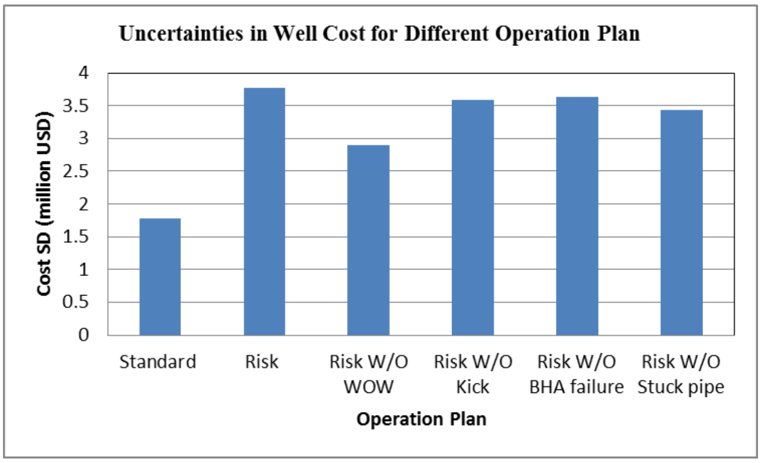

Figure 58: Uncertainties in well cost for different operation plan

Table 22 and figure 58 present the uncertainties in the estimated well cost for different operation plan. The results shown here agree with the uncertainties in well duration where the risk operation plan has obviously higher uncertainty than the standard operation plan and the WOW event has the largest effect on uncertainty among other events. Based on the assumption that the extra cost of the events is absorbed in the spread rate/drillstring cost and the stuck pipe can be released without leading to Lost in hole (LIH) incident, the extra duration due to the events are the main factors which affect the results. Thus, it is reasonable that the uncertainties in well cost show the same trend as the uncertainties in well duration for different risk operation plan.

Both well duration and well cost analysis specify that WOW is the most dominating factor of the uncertainties of results compare to other undesirable events. One possible reason could be that this event has an obviously higher probability of occurrence. Since Weibull distribution is widely accepted for WOW and weather forecasting, the probability distribution type will be fixed while the probability of the WOW event will be varied.

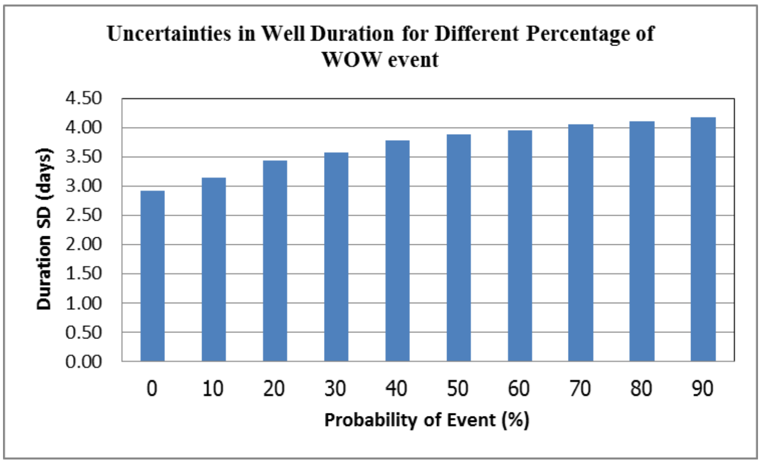

Figure 59: Uncertainties in well duration for different probability of WOW event

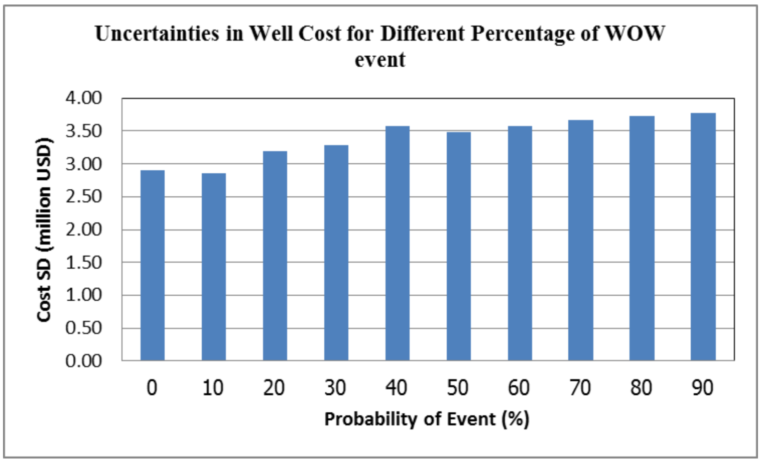

Figure 60: Uncertainties in well cost for different probability of WOW event

Figure 59 and figure 60 show how the uncertainties of well duration and well cost change with various probability of WOW event. From both figures, the result uncertainty does not change significantly with small adjustment of event probability. However, if the event probability changes considerably, it can have a noticeable effect on the uncertainties of well cost and duration. Due to the fact that the probability of WOW event highly depends on both the time of the year and installation type, the uncertainties of results could change notably if this information is known prior to running the simulation.

Value Analysis

Well Duration Analysis

Operation Plan	Expected Duration (days)
Standard	29.98
Risk	36.97
Risk W/O WOW	34.24
Risk W/O Kick	36.15
Risk W/O BHA failure	35.99
Risk W/O Stuck pipe	34.31

Table 23: Expected duration for different operation plan

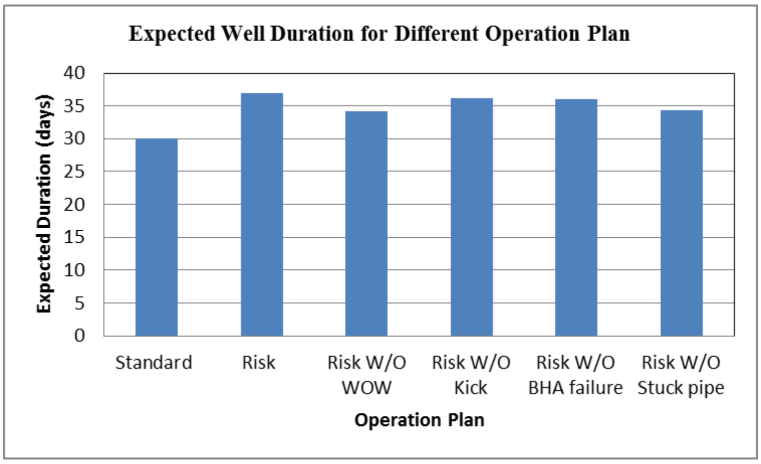

Figure 61: Expected well duration for different operation plan

After performing an analysis of well duration for different operation plan, one can notice from table 23 and figure 61 that a particular event does not have a significant effect on the expected well duration. The result of each risk operation plan shows a small reduction from 2.22% to 7.38% from the normal risk operation plan. Nevertheless, when all the events are combined in the well model, the effect of undesirable events on well duration is more observable. This can be seen when we compare the standard operation plan with the normal risk operation plan.

Well Cost Analysis

Operation Plan	Expected Cost(million USD)
Standard	30.06
Risk	36.08
Risk W/O WOW	34.10
Risk W/O Kick	35.26
Risk W/O BHA failure	35.19
Risk W/O Stuck pipe	33.80

Table 24: Expected Cost for different operation plan

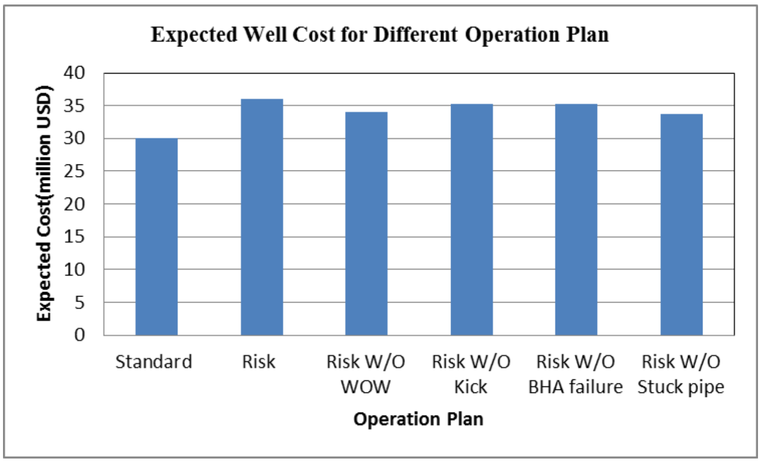

Figure 62: Expected well cost for different operation plan

The results of the well cost analysis shown in table 24 and figure 62 correspond to the results of the well duration analysis. One specific event excluded from the model leads to a minute decrease in the expected well cost from the normal risk operation plan, from 2.33% to 6.32%.

7. Conclusions and Recommendations

This study focused on performing probabilistic well cost estimation and studying the characteristics of results from an example well. Sensitivity analysis of the results has been conducted to observe how the uncertainties and the value of the results will behave when the input parameters are varied. Furthermore, the research also aimed to identify potential development for the Risk€ software.

7.1 Why Probabilistic Cost Estimation

Historically, well cost estimation had been performed by a deterministic method which is simple and easy to communicate. However, that approach turned to be too optimistic and did not reflect the range of possible outcomes. Hence, a probabilistic approach has been developed and its application in predicting well cost and duration has become accepted widely in the oil and gas industry. With this method, sensitivity analysis and risk assessment can be performed. Engineers, decision makers and stakeholders can have better knowledge regarding the expected outcome and uncertainties in well construction processes. Thus, this leads to better decision making process, more effective allocation of resources and an improvement in planning to prevent time and cost overrun.

7.2 Conclusions from an Example Well

A case example well was created with an inspiration from a Statoil well program. However, input information, especially cost related data, were estimated based on various sources which are expert comments, literatures, personal experiences, etc. Then, a standard operation plan was generated. Both well cost and well duration histograms showed similar shape, which were asymmetric and skewed to the right. When the cost was broken down into cost codes, it confirmed that time spent on well operations were obviously the most significant contribution to the well total cost.

Phase sensitivity analysis demonstrated that drilling phase and mobilization phase were the most dominating phases with respect to the total results. Deeper details were revealed in operation sensitivity analysis where it was seen that drilling operation was the most influential operation within the drilling phase and moving rig to location had the highest impact on the mobilization phase. As a consequence, rate of penetration (ROP) and rig moving velocity were selected for detailed sensitivity analysis.

To analyse the uncertainties, probability distribution type of both parameters was varied and the standard deviation (SD) of the results between each distribution type was compared. The results showed that, among 3 distribution types, the uniform distribution gave the highest uncertainties results and the single distribution gave the lowest uncertainties results. From the discussion in the last chapter, we may conclude that ROP was a significant uncertainty driver and a better knowledge of an expected range of ROP could reduce the uncertainties of the results considerably. Exact knowledge of rig moving velocity could moderately reduce the uncertainties of results, but the impact was much less than the ROP.

In order to examine the effect of ROP on the value of the results, the expected value from 4 cases of different penetration rate were plotted against each other. The first case was base case of the example well while the other 3 cases were the results when the ROP was set at the minimum, most likely and maximum of the base case ROP. The results from the “Most Likely” case were relatively close to the base case, slightly lower. This was the same behaviour seen when comparing the deterministic and probabilistic approach. In this analysis, the minimum and the maximum ROP were symmetric compared to the most likely value. However, the simulation results showed asymmetric characteristics. The maximum ROP moderately lowered the expected cost and duration to a certain level while the minimum ROP enormously exaggerated the expected results. This behaviour was confirmed by the value analysis of the varied rig moving velocity. When the rig velocity was varied, the expected cost and duration remained steady except for the case of the slowest rig velocity. If the rig moved extremely slowly, it caused a much longer delay compared to the time it could save when moving fast. This could be due to the fact that, when the operation was very slow, that operation would have a higher proportion of the total estimation. Thus, it led to a much greater expected results. On the contrary, when the operation was much faster, that operation had less impact on the estimated results and other operations would contribute more. That’s why it did not lead to a huge decline in the expected results.

After performing detailed sensitivity analysis of the standard operation plan, 4 major risk events were included into the simulation and the risk operation plan was generated. When comparing the results from the standard operation plan and the risk operation plan, the latter had much greater dispersed data. This led to much higher standard deviation and exceptionally longer tail on histogram charts for both cost and duration. The effect of each event on the total duration was examined by excluding the event from the simulation one at a time. According to the event sensitivity analysis, wait on weather (WOW) demonstrated the greatest impact among all the risks. The uncertainties of results dropped significantly when it was excluded from the simulation as well. On the other hand, the kick event and the BHA failure event showed a negligible change when they were excluded from the simulation. WOW was examined if its high probability of occurrence was the key driver of the results. Then, it was found out that if the probability of WOW event changed significantly, a noticeable decrease in uncertainties could be expected. Hence, knowing the time of the year that the operations would take place and the installation type that would be used could lead to more accurate results.

Even though the risk events were responsible for huge increase in uncertainties, the impact on the expected values were not that obvious. There was no particular event that clearly influenced the expected results. Excluding each risk event from the simulation only showed a small reduction from the normal risk operation plan.

It was mentioned before that time spent on well operations had a huge impact on the estimated cost and time-based cost had a large proportion of the total cost. This was confirmed by the study where all the cost analysis showed the same trend as the duration analysis. The only difference was that the magnitude of change in the well cost was slightly smaller than in the well duration. This was reasonable since the cost was also contributed from the fixed cost which would not change with the changing duration.

7.3 Recommendations for Future Study and Software Development

One goal of this study is to identify the potential improvements of the Risk€ software to enhance the efficiency of future study. During the research, there are some ideas which I think could be appealing to appraise more thoroughly if these could be developed in the future version of the Risk€ software. The suggestions are from the literature review, simulation and analysis process and personal experience as a software user. These recommendations are divided into 2 categories. The first one is the suggestion for the software to expand its function and be able to handle more well operations situations. The second one is the opinion about how the software could be improved to be friendlier to the user.

7.3.1 Software Development to Cover More Well Operations Situations

- In the example well consideration, the well was designed to drill a 6” pilot hole prior to plugging back and sidetrack the well. However, the well architecture cannot handle this situation. The sidetrack section cannot be represented in the well schematic and the software treats the sidetrack section as the deeper section from the 6” pilot section. I would like to propose that Risk€ should be extended to set up the well architecture for a multilateral well.
- When dealing with the stuck pipe event, the user can add extra duration and extra cost associated with the event. In spite of that, the software does not provide an option to separate between the cases where the pipe can be released and the lost in hole (LIH) situation. In case of LIH, a huge extra cost due to BHA would occur. Besides, the well will need to be plugged back and sidetrack. These costs cannot be simply added as an extra cost of the stuck pipe event; otherwise, it will be directly treated as the cost of the event no matter the pipe can be released or not. Thus, I would recommend that the software will be able to deal with “what-if” scenario and the results from each case could be compared. A similar situation can occur for a kick event. If the kick event evolves into a blowout, the consequences will be much more devastating in terms of operations cost and duration.
- One common decision to be made during drilling is if the bit becomes dull, where the

decision is between continue drilling with the same bit and encounter slower ROP or trip out of hole to change the bit. In order to compare these 2 scenarios, it would be convenient for the users if the different range of expected ROP can be selected in one section. The expected range of ROP can have a huge difference between drilling with the new bit and the worn bit.

- As mentioned earlier, this simulation tool divides the drilling operations into phases and it works with one well at a time. This is more suitable for an exploration well. For the field development campaign, batch drilling technique can be used. It would be great if the software is extended to support this technique.
- While working with batch drilling, it is believed that the work efficiency tends to improve and less time will be required for the same operation. Thus, if the software is extended to support batch drilling technique, the learning curve effect should also be included.
- While planning the well, not only the cost of drilling operations, but the cost due to running completion processes is also an important concern. Broadening the software features to cover the completion processes would be a great benefit for both the engineers who write the AFE and the decision makers.

For future study, once the software is developed to cover these cases, it would be interesting to perform well cost and duration estimation for these scenarios. It could also be appealing for Risk€ to have a potential for analysing new drilling technologies compared to the conventional approach. New technology is likely to be more expensive with lack of historical data but may lead to better efficiency operation while the conventional method is more predictable. A risked base approach could be appropriate for analysing this.

7.3.2 Software Development to Enhance Efficiency in Simulation Process

- In the distribution mode input panel, the user can select either the common distribution; such as single value distribution, discrete distribution, uniform distribution, triangle distribution, piecewise linear distribution, or the advanced distribution; such as generic distribution, normal distribution, exponential distribution, Weibull distribution, is more appropriate for that parameter. Nevertheless, for some parameter such as ROP, the advanced distributions are disabled and cannot be selected.

- One advantage of the software is that several alternatives can be compared with each other. It would strengthen this advantage if there is an option to copy alternative. Sometimes, the alternatives to be compared may be different in only few phases or operations and the rests of the well model are the same. Thus, it would be much faster to compare many alternatives when the users only need to work with the processes of interest and no need to create the whole well again. This idea also applies with phase and operations. It should be possible to copy them such that the user only needs to change the necessary inputs.
- The normal distribution may be appropriate with many input parameters. However, it might not be chosen for the simulation since its tail could give an unreasonable value. For example, it may give a negative value which is not sensible for many parameters. Thus, it would be advantageous if the user can set the boundary (cut off) for the normal distribution in the software.

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Appendix A: Matlab Code

- Matlab code for Monte Carlo sample calculation
    - Drilling cost estimation without events.

```
function C =  calCost(N)
ROP = trianglerand(5,20,35,100000);
%ROP in m/hr.

for i = 1:N

   Length = 1000; % section length is 500m.

   Rigrate(i) = unifrnd(4,7);
   % Daily rig rate is in million NOKtitle

   C(i) = 1000/ROP(i)*Rigrate(i)/24 + 2;
   %fixed cost is 2 millionNOK.

end

N = 100000; % number of repeated trials

C = calCost(N);

hist(C,500); % 50 is number of histogram columns

mu1 = mean(C);

me1 = median(C);

sd1 = std(C);
```

- Drilling cost estimation with events included.

```
function Z =  calCost2(N)
ROP = trianglerand(5,20,35,100000);
   %ROP in m/hr.
Event = trianglerand(2,30,60,100000);
for i = 1:N

   Length = 1000; % section length is 500m.
   Rigrate(i) = unifrnd(4,7);
   % Daily rig rate is in million NOK
   C(i) = 1000/ROP(i)*Rigrate(i)/24 + 2;
   %fixed cost is 2 millionNOK.
   on = (rand<0.2);
   Z(i) = C(i) + Event(i)*Rigrate(i)/24*on;
end
N = 100000; % number of repeated trials

Z = calCost2(N);
hist(Z,500); % 50 is number of histogram columns
mu2 = mean(Z);
me2 = median(Z);
sd2 = std(Z);
```