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Abstract

Geothermal energy is today recognized as a weather independent and stable energy source with significant potential. The high cost of drilling long-reach wells is a key bottleneck and a show stopper for the realization of widespread exploitation of deep geothermal energy. Estimates for deep geothermal projects show that the drilling and well construction cost can be as high as 80% of total investment costs.

Therefore understanding the intimacy of the costs involved in geothermal well construction will give an insight on how to reduce drilling costs and make EGS (Enhanced Geothermal System) a profitable investment for the upcoming years. For this reason, construction cost and duration simulation for a deep EGS well was performed using Risk€, a simulator developed by IRIS that uses Monte Carlo method for calculating oil & gas well budgets. Even though the simulator was designed for hydrocarbon wells, the software's structure can execute easily a geothermal well, which has the same cost and duration variables as an oil & gas well.

The simulator offered the option to add risk events to the operational plan and simulate with more uncertainty, taking account of events such as stuck pipe, wellbore instability and improper cement jobs, which are common on the geothermal experience.

The results from the simulation gave a deterministic and a probabilistic view summarizing the complete costs and duration of every phase and operation of the well. The presented results offers mean, standard deviation, P10, P50 and P90 values for understanding the project uncertainty. Sensitivity analysis was performed to the input parameters for distinguishing which of them affect the final cost and duration the most, and therefore are key factors for the well construction.

ROP was recognized as the most influent parameter for the whole well construction process, so a decrease and several increases for this parameter was varied for understanding how much can affect the final cost and duration. It was found that if the ROP had an increment of 1 m/h in every drilling phase, around 10% of the final well cost can be saved and will take 17% less time to finish the well construction. More comparative findings with different ROP values are explained in the present project.

Acknowledgement

Dedicated to all the people I was ungrateful, I am truly sorry and I am really blessed because y'all helped me several times with lots of kindness. Sincerely thank you.

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Nomenclature

BHA - Bottom Hole Assemblies

BOP - Blow Out Preventer

CDF - Cumulative Distribution Function

EGS - Enhanced Geothermal System

ID - Inner Diameter

LOT - Leak Off Test

LWD - Logging While Drilling

MCS - Monte Carlo Simulation

MU BHA - Make Up BHA

MWD - Measurement While Drilling

OD - Outer Diameter

PDF - Probability Density Function

POOH - Pull Out Of Hole

RIH - Run In Hole

ROP - Rate Of Penetration

RPM – Rotation Per Minute

R&D – Research & Development

SA - Sensitivity Analysis

SD.- Standard Deviation

WOB – Weight on Bit

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1 Objectives

1.1 Main Objective

To prepare a budget for an EGS (Enhanced Geothermal System) well using Monte Carlo Simulation.

1.2 Secondary Objectives

- Study onshore EGS drilling technology, considering available technology.
- Understand the technological comparison between oil & gas and geothermal industry.
- Formulate probability distributions for well costs and parameters, based on the available geothermal drilling experience and literature.
- Analyze the MCS results by considering the economic viability of well investment and further development.
- Identify the economical limits of different key parameters, such as ROP, expected bit life.

2 Introduction

Geothermal energy resources is a promising source of energy for the future, considering the growing global energy demand and the growing need to replace nuclear energy and coal-fired energy with more environmentally friendly choices.

There are two types of geothermal energy sources (Tester et al, 2006); the first and most known one is hydrothermal, traditionally named the conventional geothermal source. A hydrothermal reservoir rock is characterized by a high temperature-depth gradient (i.e., geothermal gradient), high permeability and porosity from the rock, enough fluids in place and an adequate reservoir recharge of fluids. The second type of geothermal energy is the "unconventional geothermal source" known as EGS (Enhanced Geothermal Systems). This geothermal energy source lack at least one of all the conditions required for a hydrothermal resource. For example, a reservoir rock could have high geothermal gradient but not produce enough fluid for feasible heat extraction, either because of low formation permeability and insufficient reservoir volume, and/or the absence of natural fluids.

There are more challenges in drilling a geothermal well compared to drilling in an oil & gas environment (Tester et al, 2006). Whereas oil and gas environment is characterized mainly by sedimentary rocks, geothermal wells are mainly drilled through igneous and metamorphic rocks. This means, in geothermal environments, the rocks are harder to drill and ROP is reduced drastically. Also because of high abrasive rocks, the need of more bits in each section has to be considered. All this challenges and risks bloats the overall budget which has the potential to reduce the interest of investors and further complicates the development of this technology.

This project introduces the Monte Carlo Simulation for preparing a Well budget. The purpose is to define a means to appreciate and analyze the various cost parameters and to define the boundaries conditions within which these parameters can enhance investment opportunity. A Well construction cost simulator, Risk€ provided by IRIS would be used in this project and the input data for the simulation would be taken from Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report by Polski et al (2008). The focus will be on probabilistic approach of calculation. After results are obtained, sensitivity analysis will be run with some parameters to determine how the different probability distribution scenarios affect the results.

3 Theory

The purpose of this chapter is to introduce some basic concepts needed to understand the various techniques and methods adopted in cost estimation and simulation. The focus of this work is on cost evaluation for geothermal well construction and all the concepts discussed here are explained in relation to these main topics.

3.1 Definition of EGS

Geothermal energy refers to thermal energy that is stored in the Earth's crust. This thermal energy is distributed in the host rock and the interstitial fluid stored in pores and fractures at temperatures above normal condition (Lund, 2007). These fluids are mostly brines in in-situ state, even though sometimes they might consist of a saturated liquid-vapor mixture or superheated steam phase.

Previously, EGS was defined as the extraction of heat from geothermal reservoirs of low permeability and/or low porosity that needed to be enhanced or stimulated for commercial production (Tester et al, 2006). Recently, EGS definition covers the following:

- Conduction dominated, low permeability resources in sedimentary and basement formations,
- Also low productive hydrothermal resources,
- Geopressured-geothermal energy and
- Magma resources.

Also, coproduced hot water from oil and gas production is considered as an unconventional EGS resource type.

Heat is transported to the reservoir rock located in the continental crust in two main ways:

1. Upward heat conduction and convection from the Earth's mantle and core
2. Radioactive heat engendered by isotopes like uranium, thorium and potassium that are present in the crust.

Nevertheless, it is important to study conductive and convective systems. Igneous intrusion can increase the normal heat flow locally, but mainly it is the local and regional geology and tectonics that determine the location and quality of the resource. For example, a region with higher than normal heat flow could be attributed to tectonic plate boundaries and/or areas where igneous activity are dominant and/or volcanism. Economically, the accessibility to geothermal resource is studied and other important aspects such as the drilling program to reach the depth of interest. Another condition is that the reservoir rock has enough hot fluid productivity, if the reservoir does not fulfill the required fluid recharge, reinjection procedures must be arranged for maintaining intended reservoir fluid production rates (Grant and Bixley, 2011).

Thermal energy is produce through convective and conductive processes in porous and/or fractured spaces within the reservoir rock, both happening at the same time. This heat transportation process must be done according to the limitations of the reservoir related to geologic, lithologic and hydrologic features. The idea behind this is to extract hot water or steam from the reservoir and convert it into electricity, process heat or space heat (Falcone & Teodoriu, 2008).

To produce thermal energy from reservoir rocks in EGS wells, water is to circulated through connected fractures using injection wells. The water is heated because of rock contact, ascends using production wells to form a closed loop, as seen in Figure 1.

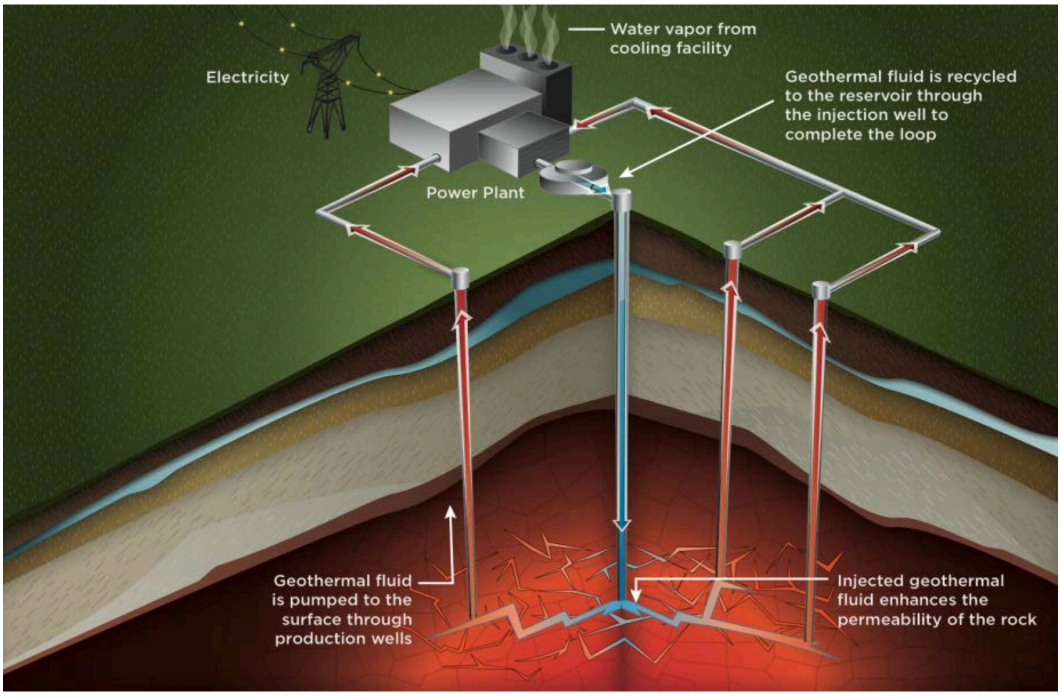

Figure 1.- Geothermal Power plant scheme for exploiting an EGS resource. Adapted from Selvans (2013)

EGS wells have to be deep enough to reach a required rock temperature to obtain a high geothermal gradien. If the encountered reservoir rock do not have the appropriate natural permeability that allows communication between the injection well and the production well, it is a stimulation job should be performed to create fractures in between these wells. If a fracture job is not needed and good permeability with confined geometry is present, water flooding or steam drive techniques could be used. (Tester and Smith, 1977; Bodvarsson and Hanson, 1977)

3.2 Geothermal Industry Facts

Some important facts about current state of the geothermal industry according to Tester et al (2006) are:

1. EGS is a renewable energy resource capable of providing continuous base-load power with minimal visual and other environmental impacts.
2. The technological progress on EGS and hydrothermal have the characteristic of complementing each other. This implies that any improvement on hydrothermal will benefit EGS and vice versa, in aspects such as drilling, reservoir and power conversion technologies.

3. The feasibility of EGS was proved for more than 30 years, by means of producing net thermal energy by circulating water through stimulated zones. It is possible to stimulate large rock volumes larger than $2km^3$ and have a connected well-circuit for circulating fluid without large pressure losses at near commercial rates and generate power with geothermal energy.
4. The main restriction until now is to assure enough connectivity within the production and injection well system in the stimulated zone of the EGS reservoir to allow high production rates without cooling the reservoir too fast.
5. Research, Development, and Demonstration (RD&D) in certain areas of EGS can enhance the industry competitiveness in a private level and allow development in deep geothermal fields of 6 km or more.

3.3 Introduction to Rocks.

Geothermal drilling, like oil & gas drilling, rocks have to be crushed in order to create the well that is going to communicate the energy source, heat in this case, to surface.

Most of the EGS projects consider onshore drilling close to places with high energy demand, such as Europe and United States, with the main requirement of having a considerable high geothermal gradient and a bottom hole temperature superior to 200°C.

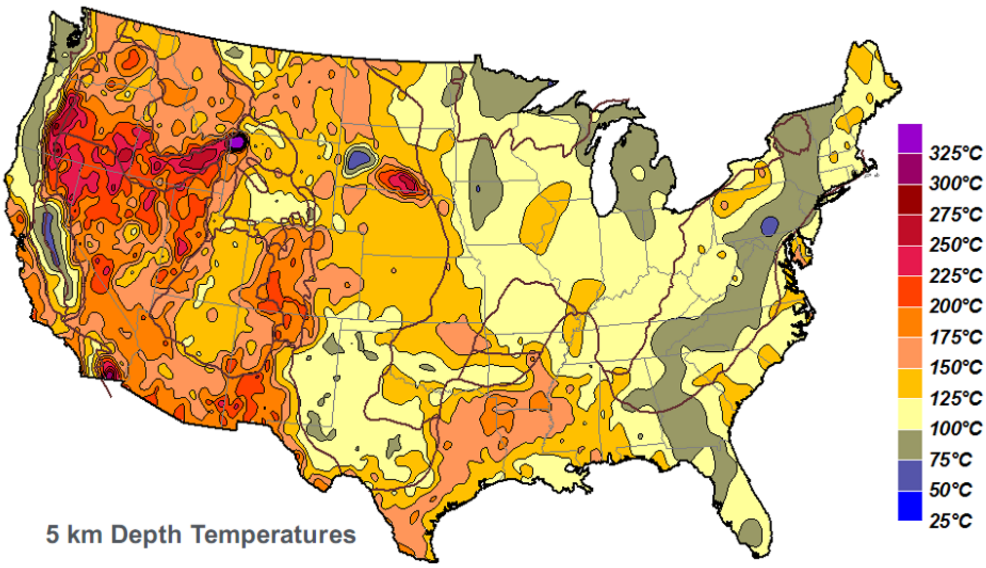

Figure 2.- Temperature at 5 km depth in United States. Adapted from J. Tester et al (2006)

3.3.1 **Sedimentary Rocks.**

Sedimentary rocks are formed at lower temperatures and pressures at the surface of the earth due to deposition by water, wind, or ice (Boggs, 2009). This process of gathering and settling organic and mineral matter (detritus) is called sedimentation, and the material transported is called sediment. Before the particles are carried, sediments were formed by erosion and weathering of another rock. Another peculiarity of these rocks is the presence of layers.

The presence of sedimentary rocks above hard, abrasive rocks in places with geothermal potential was always considered (Augustine et al, 2006). In most of the cases the depth of this sedimentary section is around 1 km as shown in Figure 3.

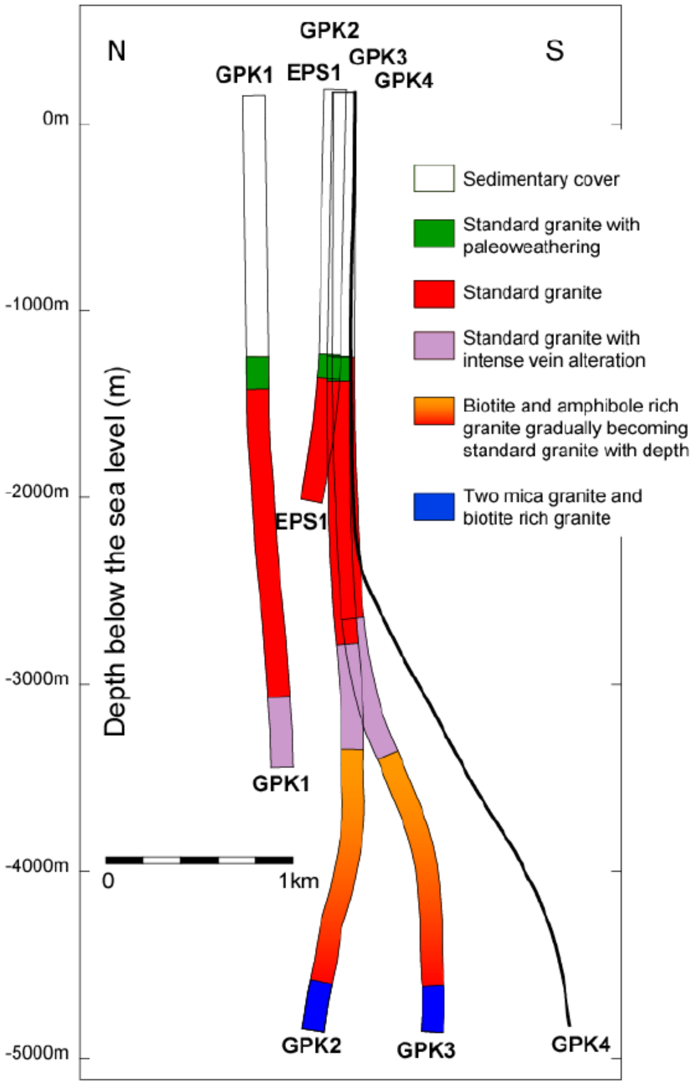

Figure 3.- N-S geological cross-section between the Soultz wells in France. Adapted from Dezayes et al (2005)

For understanding why the occurrence of sedimentary rocks only appear until 1 km to 2 km depth in high geothermal gradient environment, it must be recognized the pressure – temperature conditions under which diagenesis occurs and which conditions allow metamorphism (Boggs, 2009).

3.3.2 **Igneous Rocks.**

Igneous rocks are called when they are formed through the cooling and solidification of magma or lava. These rocks can face crystallization, which can happen either below the surface as intrusive “plutonic” rocks or the opposite extrusive “volcanic” rocks.

Igneous and metamorphic rocks make up 90-95% of the top 16 km of the Earth's crust by volume (Prothero and Schwab,2004). Meaning that in the particular case of EGS exploitation, most of the rocks drilled will be igneous as shown in the previous figure.

3.3.3 **Metamorphic Rocks**

Metamorphic rocks appear from the transformation of existing rock types, in a process called metamorphism, which means "change in form". The original rock (protolith) is subjected to heat (temperatures greater than 150 to 200 °C) and pressure (over 1500 bars) (Blatt and Tracy, 2006), causing deep physical and/or chemical change. The protolith may be sedimentary rock, igneous rock or another older metamorphic rock.

Metamorphic rocks can exist in EGS environments but not so often as igneous rocks. Most of the studies done for enhancing ROP on hard rock drilling are tested on igneous rocks (Aadnoy, 2012; Curry, 2012)

3.4 Enhanced Geothermal System Industry Description

The EGS industry has surged from the need of having alternative energy sources and thanks to the advances on the hydrothermal industry, the similarities between EGS, hydrothermal and oil & gas are inevitable, as seen on the next adapted description.

3.4.1 EGS Drilling

In terms of well construction, the geothermal industry applies almost the same technology that is used in oil & gas drilling. Even though the geothermal environment is different as mentioned in earlier sections, oil & gas drilling policies are often applied because of the constant improvement of petroleum drilling.

Oil and gas drilling do not only have longer history compared to geothermal drilling but it is also less complicated than geothermal drilling (Augustine et al, 2006). The main reason for this is the type of rock that gets penetrated during the process. While oil drilling is typically done in softer and less-fractured rock (sedimentary rocks), geothermal drilling encounter much harder igneous and metamorphic rocks that are very hard to drill (Tester et al, 2006). Some problems related to geothermal drilling are massive lost circulation, very high temperatures that can expand the casing string and monitoring equipment.

An important difference between oil & gas drilling and geothermal drilling is the production bore diameter, which increases for geothermal wells to allow a higher production rate assuring long lasting wells. For having a simple idea of the difference between oil & gas and geothermal drilling Entingh provided the next table:

Table 1. *Comparison of Deep Geothermal vs. Oil & Gas Drilling*

Geothermal (Basin & Range)	**Oil & Gas formations**
Normal to underpressured	Frequently overpressured
Frac gradient constant	Frequently frac gradient decreases
Long casing intervals possible	Frequently extra casings required
Lost circulation usually decreases with depth	Lost circulation frequently increases with depth
Moderate decrease in ROP with depth	Significant decrease in ROP with depth
Well control a function of temperature not depth	Well control increasingly difficult with Depth

Note: Adapted from Entingh et al. (2006)

3.4.1.1 Rotary Drilling

Rotary drilling is often selected for deep drilling because of its good reputation of more than a century with the tri-cone rotary bit and polycrystalline diamond bit applied by diesel-electric drilling rig to create boreholes protected by steel casings in a telescopic way for reaching the target and reducing the size of the initial diameter (Plisga,2004). The rotary system is used to rotate the drillstring, and therefore the drillbit on the bottom of the borehole. The rotary system includes all the equipment used to achieve bit rotation as shown in Figure 4. The rotational power is transmitted through the Kelly that is replaced by the Top Drive nowadays; by rotating the bit and added weight of the drill string it is possible to crush the rock at the bottom.

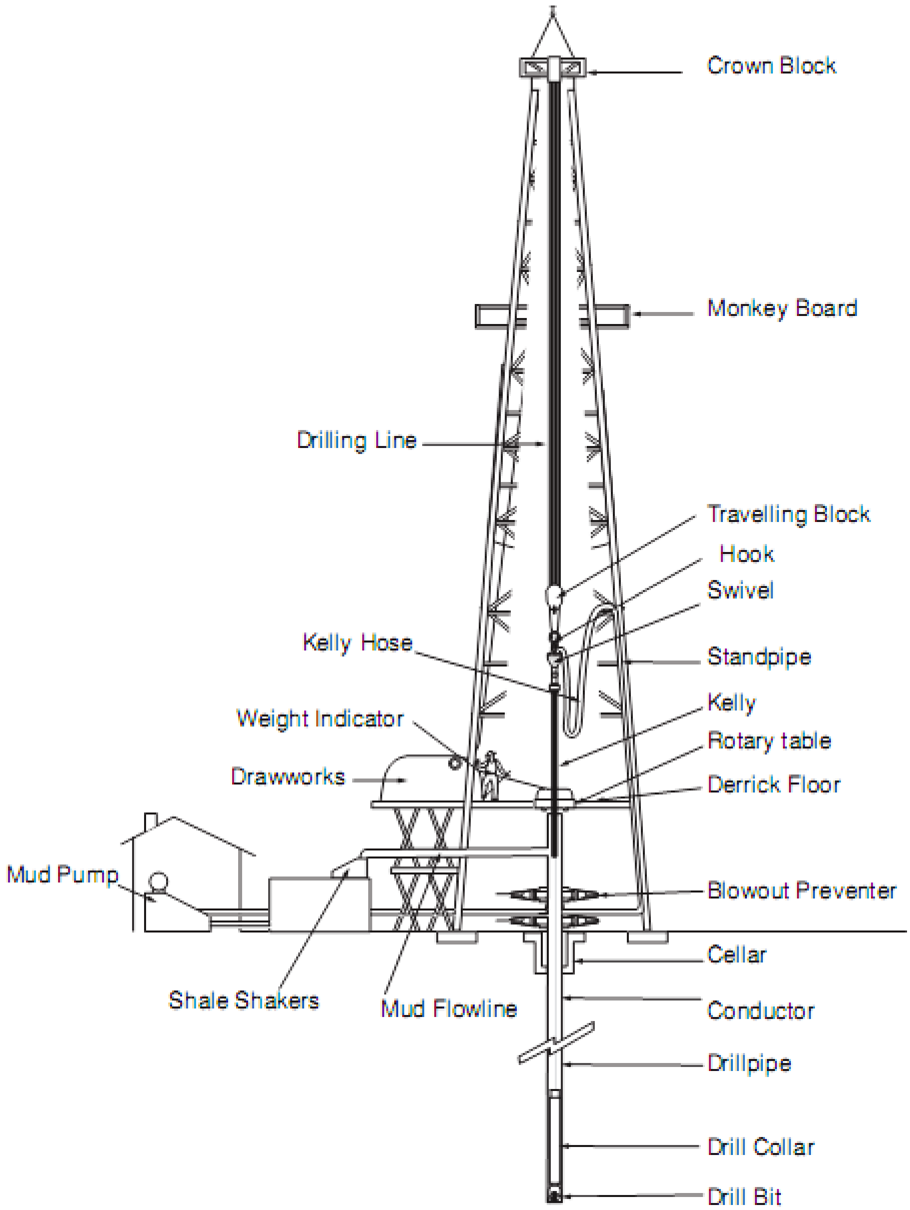

Figure 4.- Rotary Drilling rig. Adapted from Lyons & Plisga (2004)

Geothermal rotary drilling has the same principles as oil & gas drilling, and because of that the technology transfer happens in a directly manner and most of the improvements in oil & gas technology can help reduce costs for geothermal wells (Falcone & Teodoriu, 2008). Traditional examples are Top drive power swivels, air/foam balanced drilling, Polycrystalline diamond compact (PDC) bits (since the 70’s), horizontal drilling(since the 90’s) , casing while drilling(since the 50’s) , reverse circulation cementing, logging while drilling(MWD since the 90’s) , environmentally safe fluid formulations(since the 90’s) , microdrill, and coiled tubing (since the 80’s) are all good examples of these improvements (Dumas et al, 2013).

3.4.1.2 Percussion Drilling

Percussion drilling has long being used for breaking rock in the civil and mining industries (Melamed et al, 2000). This drilling method drills faster through hard formation such as granite, sandstone, limestone, dolomite, etc. and also it has been shown that with the same WOB and RPM the percussive rotary method can drill 7.3 times faster than conventional method. A large number of air hammers were introduced to oil and gas industries in the 80’s (Melamed et al, 2000).

Top hammer drilling and down the hole (DTH) or in the hole (ITH) drilling are the most common Percussion Drilling methods. Both of them use the same drilling concept, with different drill string combination (Niu, 2008). The challenge for Percussion drilling in deep hard rocks is the reduced penetration rate when facing formation water, but since fluid hammers have been presented improvements in hammer design were achieved (Pixton & Hall, 1999)

The mechanics of percussion drilling involves four main processes (Fairhust & Lacabanne, 1956):

1. Drill bit penetrates the rock with compression and vibration;
2. Rock receives the impact, propagation of stress and accumulation of damage;
3. Rock fails and breaks up and finally;
4. Cuttings are transport away from the bit and up in the annulus

The hammer bit in percussion drilling can do a higher impact along the bit movement direction. The bit breaks the rock below the bit surpassing the rock strength and forming fractures along the bit inserts (Han et al, 2006).

3.4.2 **EGS Reservoir Stimulation**

In Enhanced Geothermal System, the heated reservoir rock lacks permeability for circulating water in a closed system between wells. Therefore, a stimulation procedure is required to create an easy production flow (Grant & Bixley, 2011). It is proved that majority of heat resources in the world are contained in the Earth’s crust, being accumulated in rocks of low permeability. The aim is to develop the EGS technology in such way that energy will be produced in a profitable manner.

To produce from this low permeability formations, first we have to drill a well reaching a depth that will have enough temperature, then to increase the heat transfer to the surface, the well has to be hydraulically fractured, and finally these fractures have to intercept the production well. A field test then must be performed to ensure that enough flow exist in the injection well to the production well and the produced water is adequately heated to generate electricity and or cogenerate electricity and heat which can be used for different purposes such as industrial heat processes or local district heating.

For the past 30 years, EGS technology has undergone several improvements(Tester et al, 2006):

- Progress in comprehending reservoir characteristics like thermal drawdown, water loss rates, fluid mixing and fluid geochemistry.
- Stimulation methods have been refined to improve permeability in far and nearby wells.
- Drilling deep oriented wells
- Propagate fractures through 1 km^3 of rock
- Continuous circulation of fluids up to 25 kg/s

However, unresolved issues related to well connectivity of stimulated reservoirs are still not solved accurately. Nevertheless this does not mean EGS development is stagnant, technology is still being developed to enhance commercial feasibility.

3.4.3 Geothermal Energy Conversion Technology

Recently, several conversion techniques are available for commercial purposes (DiPippo, 2012). Some of these techniques include direct steam expansion, single- and multistage steam flashing, organic binary Rankine cycles, and two-phase flow expanders. Figure 5 presents some conversion systems.

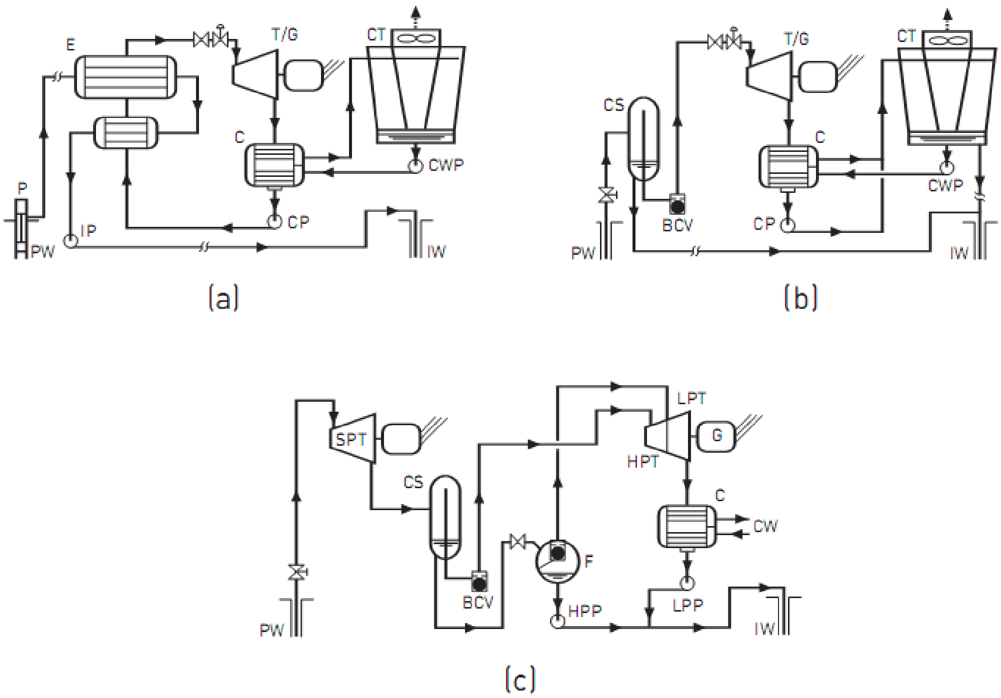

Figure 5.- Schematics of EGS power conversion systems: (a) asic binary power plant; (b) single-flash power plant; (c) triple-expansion power plant for super critical EGS fluids. Adapted from Tester et al (2006)

The actual exchange efficiency for geothermal conversion systems is around 25% to 50%, it is appraised that the efficiency will increase to 60% in the future if R&D investments are done to solve the problems of reducing the temperature differences and increasing the heat transfer coefficients using diverse mechanical solutions.

Being aware of the different applications and types of geothermal energy, the next scenarios of EGS can be considered (Tester et al, 2006):

1. Sedimentary and basement rock EGS geofluids at 100°C to 400°C can generate electricity.
2. Oil and gas operations applying organic binary power plants design at temperatures of 100°C to 180°C.

Finally, conversion systems in a commercial scale are available for all EGS geofluid types from 100°C (low temperature) liquid water to supercritical water 400°C, giving a significant opportunity for commercial purposes.

3.4.4 **Environmental Attributes of EGS**

Considering the EGS project stages such as the development (mainly well construction) and exploitation (energy/power production) structure, the power generation phase is more likely to generate pollution because of its large extension compared to the drilling period.

It has been mentioned in literature that EGS energy plants are more environmentally friendly than the hydrocarbon and nuclear industry in terms of air emission, water consumption and land use. EGS energy are significantly smaller, mainly because the energy source is downhole and the conversion equipment is relatively small and close loop circuit for energy generation (Clark et al, 2012).

According to studies done on energy resources available, EGS are one of the lower greenhouse gas emitters of the renewable systems in terms of energy produced (kWh).

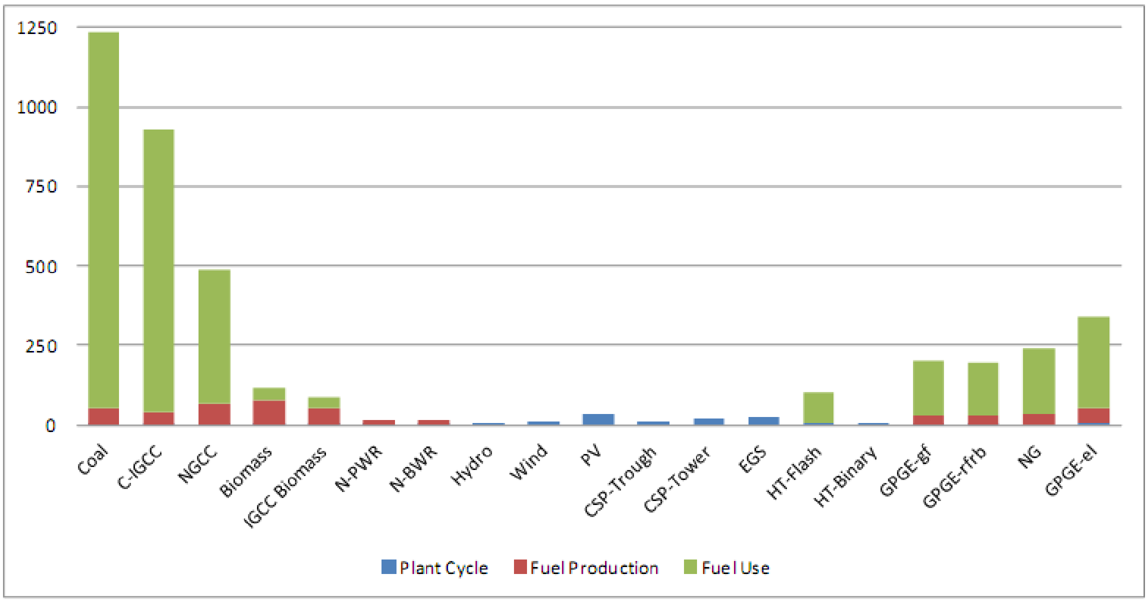

Figure 6.- Greenhouse gas emissions (g/kWh) for various power production technologies related to total energy output. Adapted from Clark et al (2012)

Geothermal plants consume less water from other electric generation compared to energy produced (kWh). In terms of water consumption, EGS plants need similar feeding as Natural gas combined cycle and biomass power generation technologies. The operational part of EGS plants is the part that requires more water because of water injection. Hence all these environmental facts points to the conclusion that all the pollution made by geothermal industry is completely manageable.

3.4.5 **Economic Feasibility Issues for EGS**

Basically the main idea behind the geothermal industry is to produce electricity, even though it has other applications related to steam use and heating. To produce geothermal energy ,a lot of investments in technology is required. There are three phases involved:

1. Exploration, and drilling of test, production and injection wells
2. Construction of power conversion plants
3. Future redrilling and well stimulation

The normal life for a geothermal project is 20 to 30 years, including the redrilling and restimulation of the reservoir around four to five times. Some of the investments include levelized energy cost (LEC), the equity and debt interest rates for invested capital, well-drilling costs, conversion plant costs, and reservoir flow rate per production well.

According to the MIT report "Future of Geothermal Energy", for a plant to become economically competitive, it needs to produce 100 MW_e

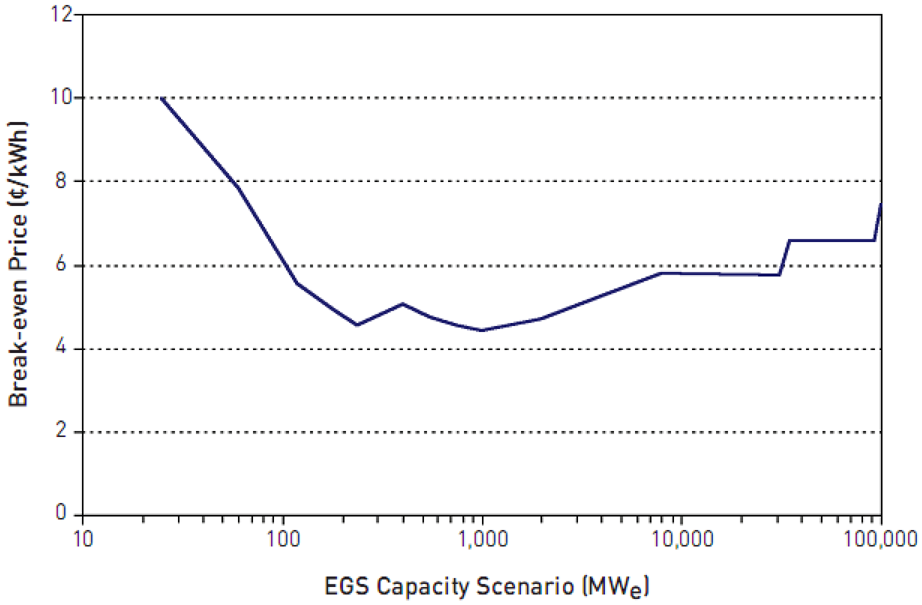

Figure 7.- Aggregate supply using MIT EGS, variable rate of return model with quartet well configuration and maximum flow per well of 80 kg/s. Adapted from Tester et al (2006)

Because of technology advances in research and learning curve effects, there is a strong correlation between the early development of new EGS facilities and the significant decline in the levelized cost of delivered electricity. This is not only reflected in the economics of new techniques and access to resources that acquire more value, but also the predictable change in disposal and increased cost of conventional energy sources.

The only EGS plant working nowadays is the one in Soultz, France that feeds the EU grid with 15 MW. They have the commitment to scale up the plant to 25 MW depending on advances in the investment on R&D can give, according to the local energy market situation, to produce energy in a commercial manner.

3.5 Geothermal Well Design

3.5.1 Drilling Fluids Scenario

The first section of the well is drilled as it is done in the petroleum industry, due to the existence of a sedimentary layer; indicating bentonite water based mud could be used. Loss circulation circumstances can occur when drilling the next section, several actions can be taken to combat this challenge (Dumas et al, 2013):

- Use of lost circulation material
- Cement plugs
- Instead of drilling with mud, pure water is used for no return situations.
- Aerated drilling mud usage is an usual choice

Severe losses are expected in EGS drilling projects because of the fractured, faulted, highly permeable basement formations present in the production sections that is essential for a potential geothermal field, assuring communication between the production and injection wells.

3.5.2 High Temperature effect

The common goal of geothermal projects is to reach 200+ °C with economical volume rates that can be obtained after stimulation and water injection. This elevated temperatures reduces the drill bit and drilling jar performance and sometimes the use of MWD instruments and mud motors is denied (Orazzini et al, 2012; Mayes et al, 2007). Also, the properties of the drilling fluid and cement slurry and BOP performance may be affected.

Meanwhile the drilling string suffers significant temperature changes because of cool drilling mud circulation and tripping in and out the well, also casing string is object of this occurrences that require special attention during operations (Dumas et al, 2013).

3.5.3 Well Design.

Well construction costs are challenging in the geothermal industry, especially when deep wells are required to reach the desired temperature. The deeper the wells, the larger the diameter of the conductor phase will be. Also, geothermal wells have to allow large production mass flows that require an electrical plant. The casing cost will increase because of larger diameter, because at high temperatures the casings experience a high compressive stress after well completion, incrementing the cost (Tester et al, 2006).

3.5.4 Cementing Casings

One particular characteristic of geothermal wells is a fully cemented casing from bottom up to surface. This is needed to combat high stresses experienced through the whole casing length because of temperature effects; this measure will distribute the stress along the complete casing extent. Another approach is to execute a casing tie back, being considered sometimes as more expensive (Dumas et al, 2013).

3.5.5 Liner Sections

The liner sections are commonly found in the production intervals, it is mentioned that liner sections must be fully cemented as casing sections (Tester et al, 2006), but a recent book published by GEOELEC on March 2013, mentions that liners are not cemented, but either hung from the previous section or sat on the bottom hole, leaving the liner top free avoiding thermal expansion or contraction (Dumas et al, 2013), which is not the case of the forthcoming simulation.

3.6 Theory of Well Cost Analysis

To calculate the well budget, many factors have to be considered, each drilling phase includes an immense variety and quantity of costs that needs to be explained in details which will require a tedious spreadsheet for every service and operation done in the well. Therefore many costs have to be grouped into a single cost that can be dependent on time (variable costs) and fixed costs. Some well cost elements are listed below (Aadnoy, 2010):

- Rental cost for drilling rig (daily)
- Cost of auxiliary transportation, helicopter, boats
- Cost of drill bits and casing
- Cost of services like mud logger and directional driller
- Cost of drilling crew and operator’s personnel

The major cost driver for a geothermal project is the drilling, that consumes from 30% to 50% of the total project investment and more than the half for EGS (Dumas et al, 2013). It must be considered that this percentage will increase if a deep EGS well is planned but the prognosis of this cost does not follow a well cost index, so well cost forecasting is not accurate (Augustine et al, 2006).

3.6.1 Estimation of Well Construction Costs

The estimation of well construction costs are based on historical data related to (Hariharan, 2006):

- ❖ Time and cost for different operations
- ❖ Drilling problems generating nonproductive time and costs
- ❖ Appraisal of drilling performance

There are two methods used to estimate costs; the first one is the deterministic approach that calculates costs with single input parameters giving a single result. The other one is the probabilistic approach that evaluates the probability distribution of the input parameters. Result of the probabilistic estimates indicates the minimum and maximum value of the total cost and time spent in the well construction.

3.6.1.1 Determinist Well Cost Estimation

In the deterministic methods, single value estimation for every single parameter is taken for calculating an approximation to the supposed total cost. Uncertainties of the project, optimistic and pessimistic cases are taken into account for recalculating the total expense (Loberg, 2008).

The deterministic well cost estimation has a simple approach, showing clear results. Even though because of this simplistic view, this method does not show the full range of possible results and the probability of predicting the final cost of the project is not quantified, being underestimated or too optimistic. (Chen & Dyer, 2009)

3.6.1.2 Probabilistic Well Cost Estimation

A vast amount of drilling activity costs and time remain uncertain and therefore the final cost is found uncertain as well. To express the final cost uncertainty properly, the probability distributions of each input parameter involved must be taken into account in the well construction cost calculations. To calculate the budget, the well construction process operations are divided into sub operations and the budget is then calculated in stages. Also, identifying critical events and unwanted events is part of the cost estimation. The method applied for getting the result is the Monte Carlo Simulation technique using probability distributions (Loberg et al, 2008).

The probabilistic approach can recognize risks and opportunities earlier and give an insight on its impacts by studying the sensitivity analysis and also finding the key cost drivers, help in decision making methodology. In the other hand the probabilistic distribution does not describe the absolute amount of risk in the project and during the decision making process some subjectivity can happen if the assumptions of the model are not followed (Akins et al, 2005).

3.6.1.3 Types of Probability Distributions

In order to represent the range of values present in the random variables, several kinds of probability distributions exists, which may be divided into discrete and continuous distributions. Discrete variable is assumed to have the probability distributed in a countable number of unit sets which means the probability function is not continuous. A continuous distribution has the characteristic to estimate an exact probability of an event at any point of the continuous curve that describes the probability distribution.

The type of probability distributions used in the simulation done in this work is mainly the continuous probability distribution.

The first type used is the uniform distribution which shows a constant probability over a determined interval. This distribution is defined over two parameters that represent the maximum value and the minimum value.

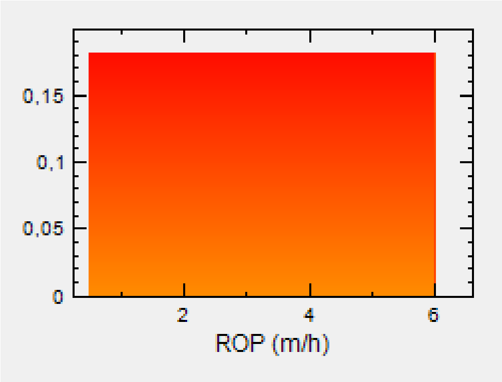

Figure 8.- Uniform Probability Distribution. Taken from Risk€ Simulator

The second type of distribution relevant in the actual simulation done is the triangular distribution. In this case, the probability distribution uses three values to determine its shape, the minimum value, maximum value and a peak value. Triangular distributions are used mostly in the simulation because they present the input parameters present in the simulator much more clear; they are suitable when there is no enough information on the input data but the minimum and maximum and the most likely value are easy to obtain from experience or available material.

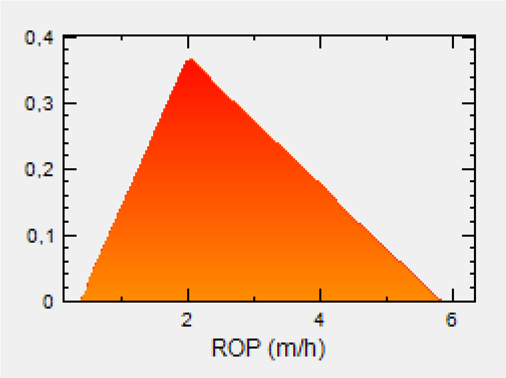

Figure 9.- Triangular Distribution. Taken from Risk€ Simulator

The last type of distribution is a single value distribution, which defines the complete likelihood of the parameter in a single value assuring 100% of occurrence.

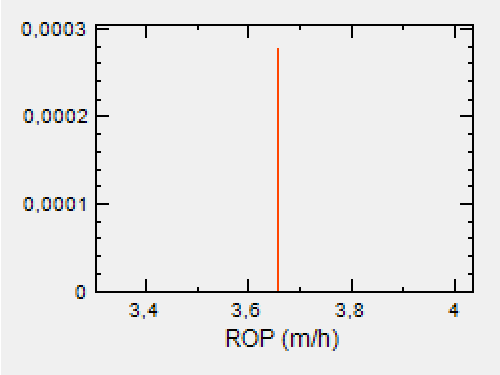

Figure 10.- Single Value Distribution. Taken from Risk€

4 Possible Risk events affecting drilling operations

Forecasting the total well construction cost requires recognizing possible events that will delay well operations. These events affect the operation duration and can have a significant impact on the costs as well. The risk events related to geothermal drilling are in some aspects different than the petroleum industry. The following events have small chances to happen in an EGS environment:

- Kick: The presence of hydrocarbons on geothermal drilling experience is not mentioned as a potential risk. Even though shallow hot water kicks were detected on kicks in Tiwi (Philippines) and parts of the Salton Sea (California) due to overpressure zones (Finger & Blankenship, 2010). The common case for geothermal drilling is underpressure, but this does not imply lack of well control measurements on geothermal drilling, that is much similar to oil & gas procedures.
- Wait on Weather: As long as the well is located onshore, the WOW concept is not applied. In onshore, drilling operations are somehow simpler because of the vast availability of space. The only inconvenience compared with WOW could be the remote location of the well, that requires extra expenses for transportation and wait on material, which is also considered in offshore drilling.

This chapter will seek to describe the risk events that will be taken into account before simulating the EGS well, which at the same time have been frequently experienced in geothermal drilling.

4.1 Lost Circulation

The most expensive problem habitually encountered in geothermal drilling is lost circulation, which is the loss of drilling fluid to pores or fractures in the rock formations being drilled (Carson & Lin, 1982). Lost circulation represents an average of 10% of total well costs in mature geothermal areas and often accounts for more than 20% of the costs in exploratory wells and developing fields. Therefore, well costs represent 35-50% of the total capital costs of a typical geothermal project; thus, roughly 3.5-10% of the total costs of a geothermal project can be attributable to lost circulation. This loss can have the following consequences:

- If drilling mud is not enough to lift up the cuttings, the BHA downhole can get stuck.

- Losing drilling fluid formulated for hot formations instead of being recirculated adds extra cost.
- In geothermal wells, the production zone is also a lost circulation zone, so in order to avoid damaging the reservoir some lost circulation has to be accepted while drilling this section.
- Lost circulation leads to reducing the well's hydrostatic head, which can lead to a kick event of gas, steam or hot water to enter the wellbore.
- For ensuring a proper cementation of the well until the cement reaches surface, all nonproductive lost circulation zones must be treated.

To counter lost circulation, the following possible measures can be taken:

- Continue drilling with lost circulation.
- Underbalance Drilling.
- Drilling with Lost circulation material like fiber or particles for plugging the fractures.
- Pause drilling operations and plug the fractures with some material that can be drilled out after.

4.2 Stuck Pipe

Stuck pipe happens when a part of the drillstring, such as drill pipe, drill collar or BHA, becomes immovable in the hole (Kullawan, 2012). The drillstring can neither be rotated nor moved. 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.

It has been already mentioned that the "mechanical" sticking is caused by cuttings and chips trapping the BHA, which is often misinterpreted as differential sticking due to the differential between the drilling fluid pressure and the pore pressure (Finger & Blankenship, 2010). Many intervals encountered in geothermal drilling are under-pressured, which stuck pipe can occur. Even though the pipe is stuck, it is still possible to circulate. Therefore, to solve this problem, lubricants are used to reduce the fluid loss. Another option is to reduce the mud weight, but often differential sticking is confused with mechanical sticking.

4.3 Wellbore Instability

The common causes of this problem in geothermal wells are:

- Fractured rock or degradation of the borehole wall due to fluid invasion.
- Sloughing or unconsolidated formations affect the hole cleaning sticking the pipe.
- Swelling clay has the potential of reducing the diameter and trapping the tool.
- Differential stresses can create an unstable hole, which is applicable on directional wells.

4.4 Difficult Cement Jobs

Because geothermal casings must be cemented completely back to surface, there is often a problem getting a competent cement job where the formations have shown either low strength or lost circulation (Finger & Blankenship, 2010). Also it is important that the cement job is done properly so that no water is trapped , avoiding the chance of casing collapsing as the wellbore goes through its temperature cycles. The most common method for doing this is to use very light weight cement for low pressure/low strength zones. If lost circulation zones are faced, the cement will not reach surface, thus a top job can be done to complete the cementation. A top job simply means to complete the cementation with small diameter tubes placed in the casing annulus that pump cement on the remaining non-cemented part.

The cementing techniques used in geothermal drilling are mainly three. The first option is to pump cement slurry ***"through the casing"*** via cementing head connected to the top of the casing string, implying that the needed slurry for the operation has to be calculated and pumped as batch because the inner volume of the casing is more larger than the annulus (Hole, 2008). The next option is to use an "***inner string"*** that is run into the casing and connected to a receptacle at the float collar, which is located at the first or second joint of casing. In this case the amount of cement pumped is not finite and cement can be pumped continuously. This method is not recommended for deep casing sections because meanwhile the inner pipe is installed the weak formations drilled will be packing off against the casing. And the last method used is to do ***"reverse circulation"*** involves pumping cement directly to the annulus, displacing the fluid back to the casing shoe and through the casing back to surface. This last method is applied when cementing the shoe is not possible with the method mentioned earlier.

5 Pre-Simulation

The basic concepts are explained in the previous chapter and this chapter describes the simulator and input data used in the simulation.

To present the investment for a geothermal project there is the need to develop programs capable of modeling cost. The purpose is to help in the decision making process on geothermal projects.

5.1 Introduction to Geothermal Cost Simulators

Geothermal simulators are built to show cost-benefit analysis and show the major cost drivers of the complete project of each geothermal R&D project.

5.1.1 **GETEM.**

The GETEM (Geothermal Electric Technology Evaluation Model) is a techno-economic analysis tool for EGS and hydrothermal projects. The cost calculations are analyzed in Resource definition and confirmation, Well-field construction, Reservoir management, Conversion system and Economics. The well cost is found out through a number of variables not related to the well construction itself, but just some generic factors that gives results as a function per depth (Young et al, 2010).

5.1.2 **ENGINE.**

The ENGINE project (Enhanced Geothermal Innovative Network for Europe) was a coordinated action supported by the R&D framework in the European Union with focus on investigation of geothermal projects all over Europe. This effort brought a tool for Performance Assessment that concentrated on the Basin Properties, Underground Development (Well), Surface Development and economics. This model evaluates the economic performance and uncertainties by means of capital expenses, operating expenses and energy prices. The well construction cost phase is illustrated in terms of length of the borehole and a scaling factor that corresponds as inputs in the spreadsheet (Randeberg et al, 2012).

5.1.3 **Wellcost Lite**

Some tools for geothermal energy cost estimation were developed to describe the total investment in a geothermal project, both EGS and hydrothermal. These tools (such as GETEM and ENGINE) do not describe the details of the well costs. Geothermal Well construction costs are considered as a direct input or based as a simple function of depth, emerging the need for a detailed simulator based on well operations (Randeberg et al, 2012). Even though, some programs are adaptable for geothermal drilling like WellCost Lite. That requires the information of (Mansure et al, 2005):

- Well configuration (well depth, hole diameter and casing diameter)
- Pre-spud and mobilization,
- Location specifics,
- Daily operations (rig day rate, fuel and power) and
- Interval costs (bit, fluids, lost circulation, etc.)

The cost simulation methodology described before is much like the processes in Risk€, that will be explained later in this work. The context for the simulator is a fractured/faulted environment with volcanic and sediment stratigraphy focused exclusively on geothermal costs, according to Mansure et al (2005).

5.2 Monte Carlo Simulation

The Monte Carlo simulation is a computerized mathematical technique that evaluates prospects or analyses problems that involve uncertainty, and used in assessing risks and decision making (Peterson et al, 1993). The methodology gives probability and value relationship for key parameters according to the simulation.

A Monte Carlo Simulation is a model that works with one or more equations. For the input variables all or some of them can be probability distributions instead of a deterministic value, for describing the probabilistic distribution one has to decide the type of distribution that suits the variable better, guided by the historical data and the user's experience. It must be understood that this input variables are independent, dependency relations can be included in the model. After simulation, the results are shown as probability distributions displaying the range of possible values. In order to obtain results, the method does a succession of hundreds or thousands of trials with values that are randomly selected from the input data probability distribution. After the required number of trials the results are sorted into histograms or cumulative distribution functions.

5.2.1 Procedure of Monte Carlo Simulation

The procedure for Monte Carlos Simulation is divided into 5 stages (Williamson et al, 2006):

- **Definition of an Appropriate Model:** Before executing a MCS, the objectives and the scope has to be defined. Considering this project, there is the need to provide support for planning the well construction and duration. Also risks, opportunities, contingencies should be considered in the model.
- **Data Gathering:** To represent a full range of possible outcomes, the gathered data set should be large enough.
- **Suitable Probability Distribution for Input Variables:** There are two steps, the first is to define the distribution shape, like uniform, triangle or log normal and the next step is to state the parameters such as minimum value, maximum value, standard deviation, etc.
- **Randomly Sample Input Distributions:** The first step is to transform the probability density function (PDF) into a cumulative distribution function (CDF). After that a uniform value is chosen from 0 to 1 and the selected number is used to enter the vertical axis of the CDF function and then goes down to the horizontal axis to obtain a unique value, as seen in Figure 13 (Bratvold & Begg, 2010).

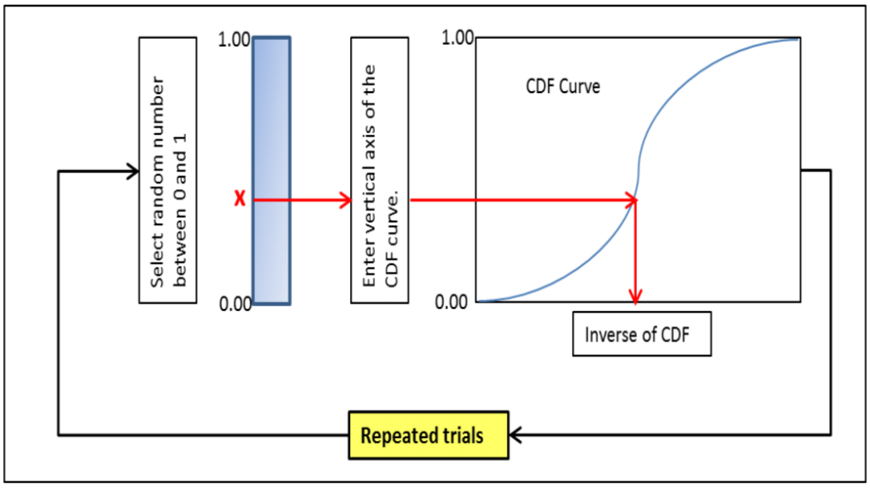

Figure 11.- Schematic of input parameter generation. Adapted from Bratvold & Begg (2010)

- **Compute the Model results and Generate Statistics of results:** With the found value of the CDF inverse as input, the first trial is calculated and stored; subsequently the whole process is done several times as needed. With the stored results an histogram is built to display this statistic.

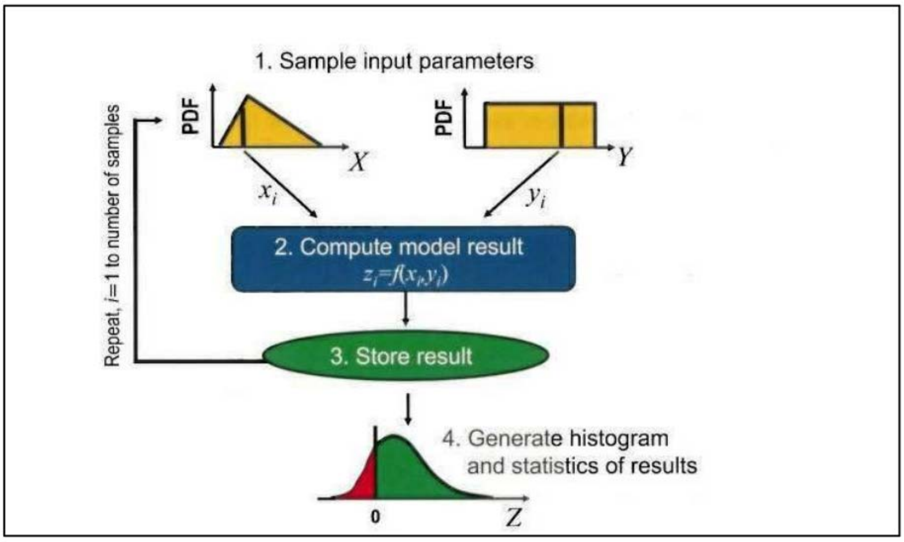

Figure 12.- Schematic of Monte Carlo simulation procedure. Adapted from Bratvold & Begg (2010)

5.2.2 Sensitivity Analysis

Sensitivity analysis is defined by Saltelli et al (2004), "The study of how the uncertainty in the output of a model (numerical or otherwise) can be apportioned to different sources of uncertainty in the model input". For Monte Carlo Simulation, the sensitivity analysis determines the input parameters influence in the final result.

In the case of well cost estimation the tornado diagram is used for single-factor analysis that determines the parameter's sensitivity by varying one factor and keeping the rest on their base value on a standard condition. This approach helps to find 2 decision-driver types:

- Uncertainty Drivers, which are the model-input variables which have the highest impact on the results.
- Value Levers, which are model's input parameters which have most impact on the estimation.

5.3 Risk€

As mentioned earlier, the software used for simulation in this work is Risk€. This tool helps to determine the cost and time prediction of the proposed EGS well in a probabilistic way.

Risk€ is a tool that suits the goals of this project by analyzing the uncertainty associated with well construction cost and duration, providing important information for the planning phase and assist in identifying the cost and duration reducing measures. Many undesirable events related to the simulation can be added to give a better result. This software was developed by the International Research Institute of Stavanger (IRIS) with financial support from ENI (Loberg, 2008b).

5.3.1 Usefulness and Limitations of the Simulator

The Risk€ analysis tool provides a decision support for economic uncertainty management in well planning and drilling activities. This tool explains the well construction process, i.e. mobilisation of equipment, spudding, placement of BOP, drilling and abandonment, with the possibility to specify the input as required, according to the level of detail inquired in the interface. The tool handles both the standard operation plan and the risk operation plan which includes undesirable events that may occur. The operation plan is automatically generated based on user input and standards within well construction. The user has some possibility to affect the operation plan after auto-generation by means of adding extra events on the operational plan.

Input parameters for cost and duration are specified on different levels. Undesirable events are included using probability of occurrence and extra cost and duration specification.

Having in mind these restrictions, the tool allows analyses costs and duration for well construction in specific cases; it also has an output sensitivity analysis on different levels.

5.3.2 Input of Drilling Phases for Generation of Standard Operation Plan

The simulator divides the well construction operations into the several phases:

- Mobilization of drilling rig,
- Spudding of the well,

❖ BOP installation,
❖ Drilling of hole sections and
❖ Well abandonment

The user inserts the input data according to this main interface panels regarding to the probability distribution type chosen and the proper values. Each phase consists of a list of sub operations, both automatically generated from the software and manually added by the user. To start the simulation, the well architecture has to be defined first. The input parameters required are:

- Casing Shoe Depth
- Casing Hanging Point
- Casing Outer Diameter
- Casing Inner Diameter

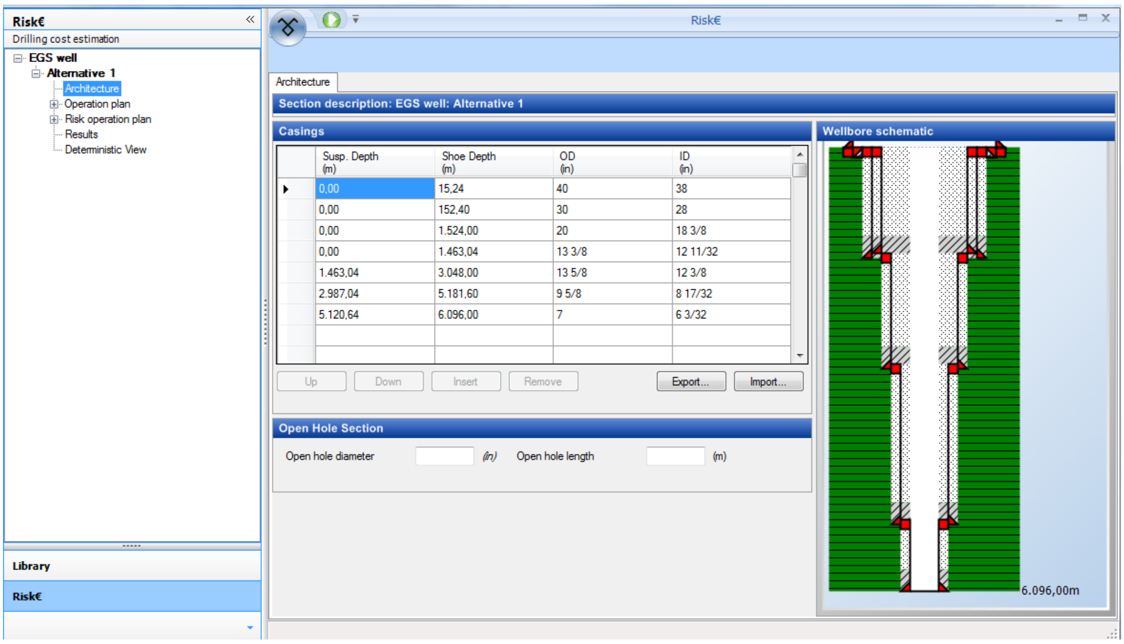

Figure 13.- Input panel for Well Architecture. Taken from Risk€

The input parameters are described for each phase editor. However, there are some parameters that are input for all phases. These are described below (Loberg, 2008b):

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 or any other fixed operational cost related to well construction in a determined phase.

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). Also is referred to the cost of several services running and personnel in the well.

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.

5.3.2.1 Mobilization of Drilling Rig

After this first step taken the next step is to add well construction phases to the simulation, the common first choice for a complete well cost simulation is to specify the mobilization costs and time. It is possible to choose the mobilization technology for offshore wells, but for onshore there is only the land rig option. Each mobilization option has different input according to the requirements of the operation.

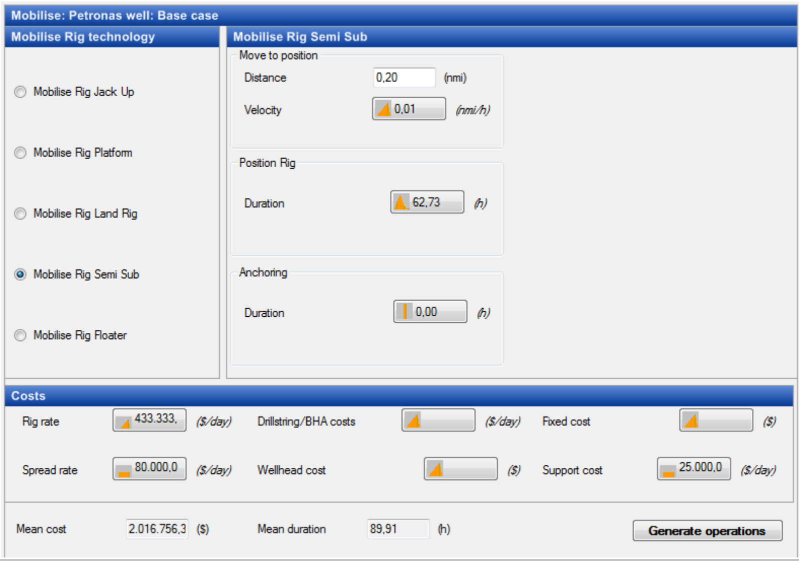

Figure 14.- Mobilization phase input panel. Taken from Risk€

5.3.2.2 Spudding

Spudding is the phase where the drilling process begins by making the top hole for installing a conductor. The simulator provides 3 technologies for computing the cost and time. Jetting is the technology where high-velocity and high-pressure fluid makes the hole in the topsoil before running the conductor. Hammering is another option available, that is simply to hammer the conductor down into the ground without drilling the hole first. Top hole states the method of drilling the hole first, then running the conductor casing.

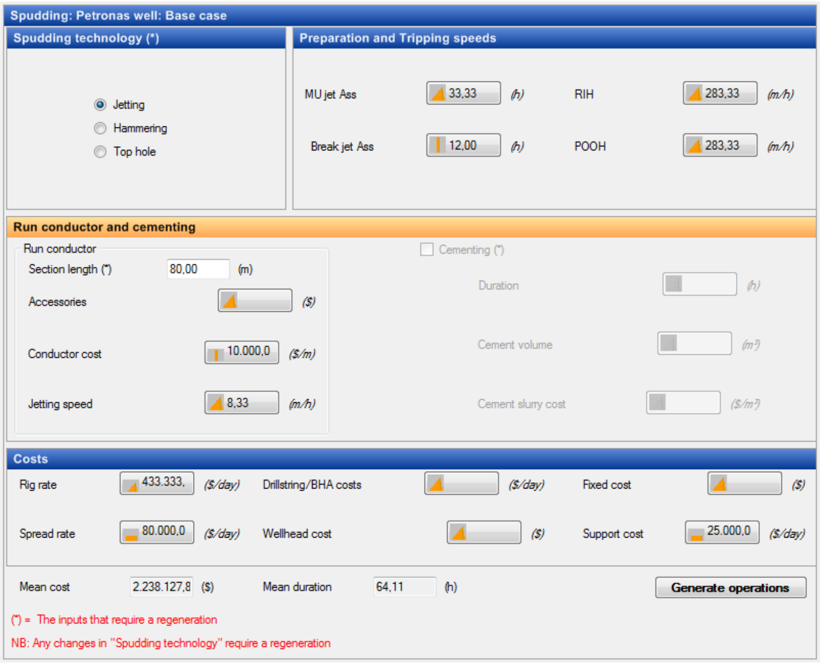

Figure 15.- Spudding phase input panel. Taken from Risk€

5.3.2.3 Drilling Hole Sections

The major part of the simulation calculations are taken part in this section, which involves the generation of the drilling sub-operations. Also the input data is classified in several categories that represent the data type for related sub-operations and phase costs. An explanation of the parameters used is presented below (Loberg, 2008b):

- Drilling/ Circulation and bit parameters
  - Section length.- The total drilled length during the phase.
  - ROP.- Rate of penetration for drilling the section.
  - Expected bit life.- Expected drill length before the bit is worn out and must be changed. 0 is considered as infinite.

- Bit size.- Size of the bit used to drill the section, i.e. open hole size before any casing.
- Bit cost.- The cost for each bit (assumed the same cost for all bits used for the section considered).
- Bit change-duration.- The time spent on changing the bit on the BHA. Should not include time spent on tripping.
- Circulation duration.- The time spent circulating the well.
- Previous casing section.- The casing outer diameter for the section above.
- Hole volume.- The volume of the open hole and cased section including volume inside riser. Not ticked check box makes Risk€ calculate the volume. Ticked check box forces the user to specify the volume in the input field behind.
- Surface volumes.- The fluid volume that will be in pit tanks etc. on the rig.
- Expected losses.- The expected fluid losses during drilling of the section.
- Fluid cost.- Fluid cost per volume, including mud and chemicals, and solids control consumables.
- Waste treatment.- Fixed cost related to handling of waste (e.g. cuttings).

➢ Drillpipe/BHA and Tripping speeds
  - MU BHA.- The time used to make up the bottom hole assembly.
  - RIH.- The speed for running the drill string into the hole.
  - POOH.-The speed for tripping the drill string or the casing string out of the hole.
  - Break BHA.- The time used to break down the bottom hole assembly.

➢ Casing and Cemented
  - Run casing or liner.- Check box to be ticked if a casing string or liner is run into the hole.
  - Casing/liner length.- Length of the casing or liner.
  - Accessories.- Costs for accessories related to running of the casing string.
  - Casing cost.- Cost per length for the casing string used for the considered section.
  - Casing services.- Costs related to casing crews and equipment.
  - Casing run speed.- The speed for running the casing string into the hole.
  - Cementing.- Check box to be ticked if the casing string is cemented.

- Duration.- The time used for cementing the casing, e.g. pumping the cement, hardening etc.
- Cement volume.- The volume of the cement that will be used for cementing the casing.
- Cement slurry cost.- Cost per volume for cement and chemicals.

- Additional Operations
  - Leak-off test.- Checkbox to be ticked if a leak-off test of the formation is going to be performed
  - New formation.- Length of new formation before LOT is performed. Must be smaller than the expected bit life.
  - Duration (LOT).- The time used for performing a leak-off test.
  - Log.- Tick the checkbox if logs are run after drilling of the section before the casing string is run.
  - Duration (log).- The time used for performing logging after drilling of the section and before the casing string is run.
  - Log cost.- Extra costs related to logging after drilling of the section and before the casing string is run.

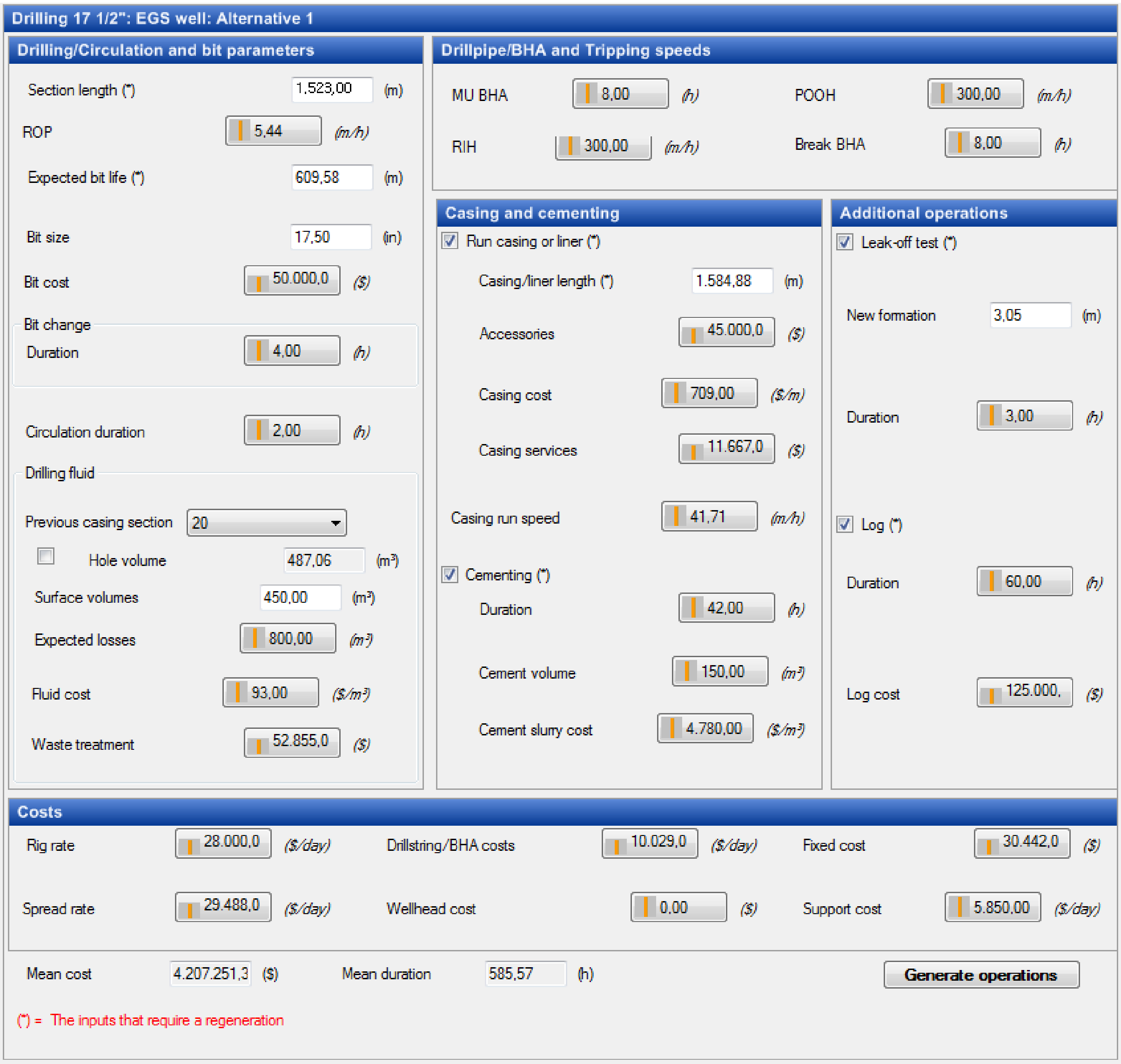

Figure 16.- Drilling example input panel. Taken from Risk€

5.3.2.4 BOP Editor

The BOP editor gives the possibility of choosing between installing the Bop on surface or at seabed. Most of the EGS well are located onshore so in our case the BOP will be installed at surface.

Nipple up BOP.- The time spent assembling the BOP.

Run BOP.- The velocity at which the BOP is run to seabed.

Pressure test BOP.- Time spent on pressure testing the BOP exclusively

Figure 17.- BOP editor input panel. Taken from Risk€

5.3.3 **Input of Risk Events for Generation of Risk Operation Plan**

After the cost and time needed to perform the simulation is estimated, it is possible to run Risk€ and generate results. The software has an option for inserting undesirable events that can affect the final time and cost into the simulation.

The risk events can be categorized into well level and phase level, and the extra cost and time needed to execute these phases can be added. The probability of those events occurring can also be fed into the simulation as input. The extra cost considered for the risk event is directly related to the linked fixed cost, such as equipment (Loberg & Daireaux, 2008b).

5.3.3.1 Risk Events in Well Level

Events involved at this level depend on complete well construction time. In this case the user can choose which phases are going to be affected by the risk event added. Another feature is to add risk events that are not mentioned in the simulator's library, for a more accurate simulation. The events available in the library are:

- Wait due to authorities
- Wait on weather
- Wait due to incident
- Wait due spills/environment
- Wait on rig repair
- Wrong well location coordinate
- Community interference
- Communication breakdown

- Wait on material
- Drawwork failure
- Top drive failure
- Other equipment failure
- Pump failure
- Power system failure
- BOP failure

Each of these events are explained briefly when the data is inserted into the simulator. Also comments about the input data can be added to this panel and the event duration and event extra cost input panels. Figure 20 shows the risk operation plan input panel.

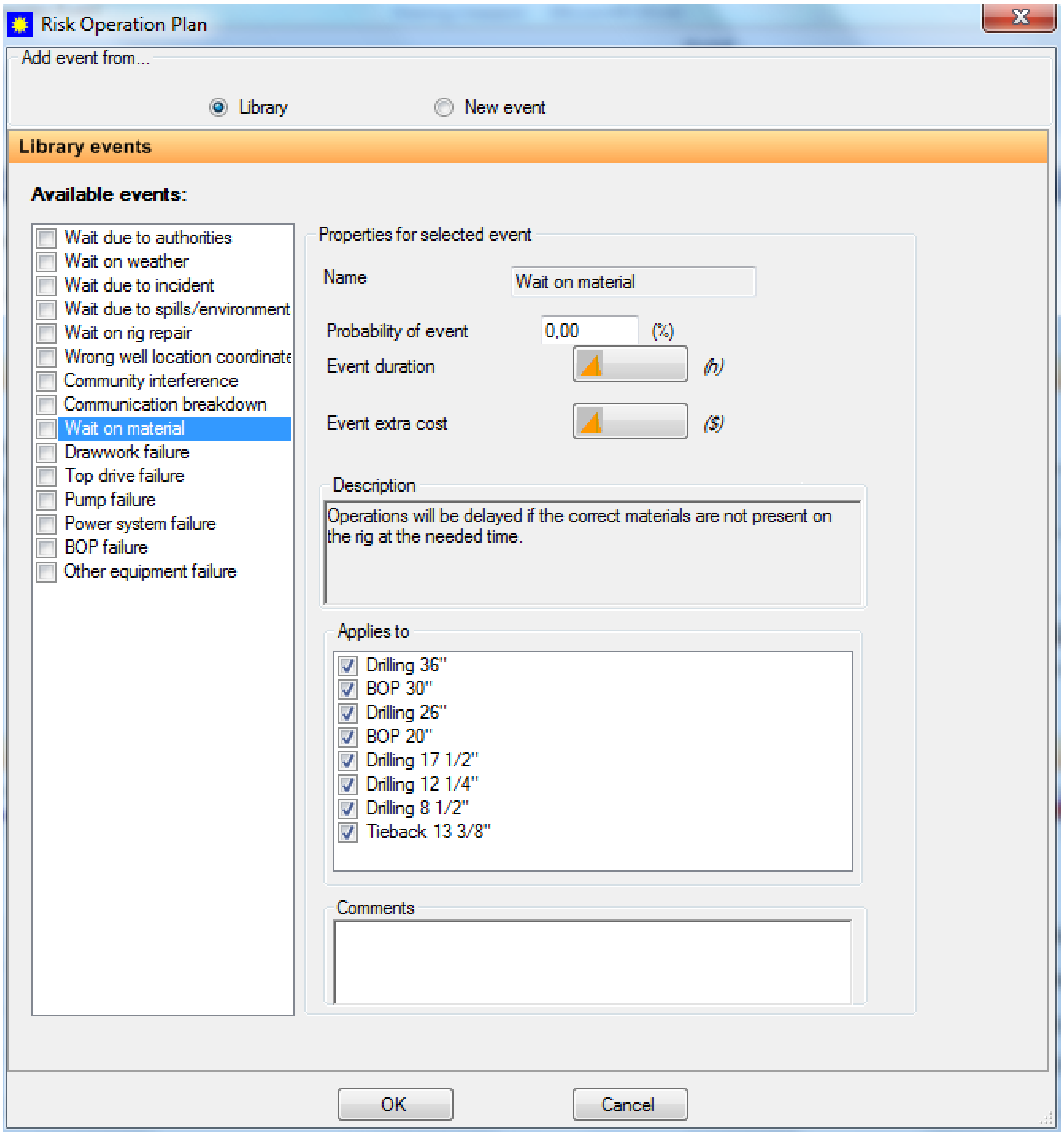

Figure 18.- Input panel for risk events in well level . Taken from Risk€.

5.3.3.2 Risks Events in the Phase Level

Some events can be added to each phase individually. These risk events are only computed for the selected phase. The Risk€ library offers different events depending on if the operation is drilling, BOP installing, mobilization or spudding. The events mentioned for a drilling phase are:

- Stability/Collapse problems
- Kick/Well Control
- Mud losses
- Hydrates
- MWD/LWD/BHA failure
- Washout
- Twist off/fishing
- Hole cleaning problems
- Tight hole
- Stuck pipe
- Barite sag
- Torque/Drag problems
- Stuck casing
- Cement unit problems
- Improper cement job
- Extra bit change
- Extreme weather conditions
- Unable to run casing to phase TD

Risk events introduced for BOP installation is much simple. The only cited risk event available in the library is “BOP equipment problems”. If the user wants to add more risk events for any phase, the same procedure used in the well level can be employed. Figure 21 illustrates that the interface is very similar to the Figure 20, but instead of choosing the phases where the event is applied, sub operations have to be chosen.

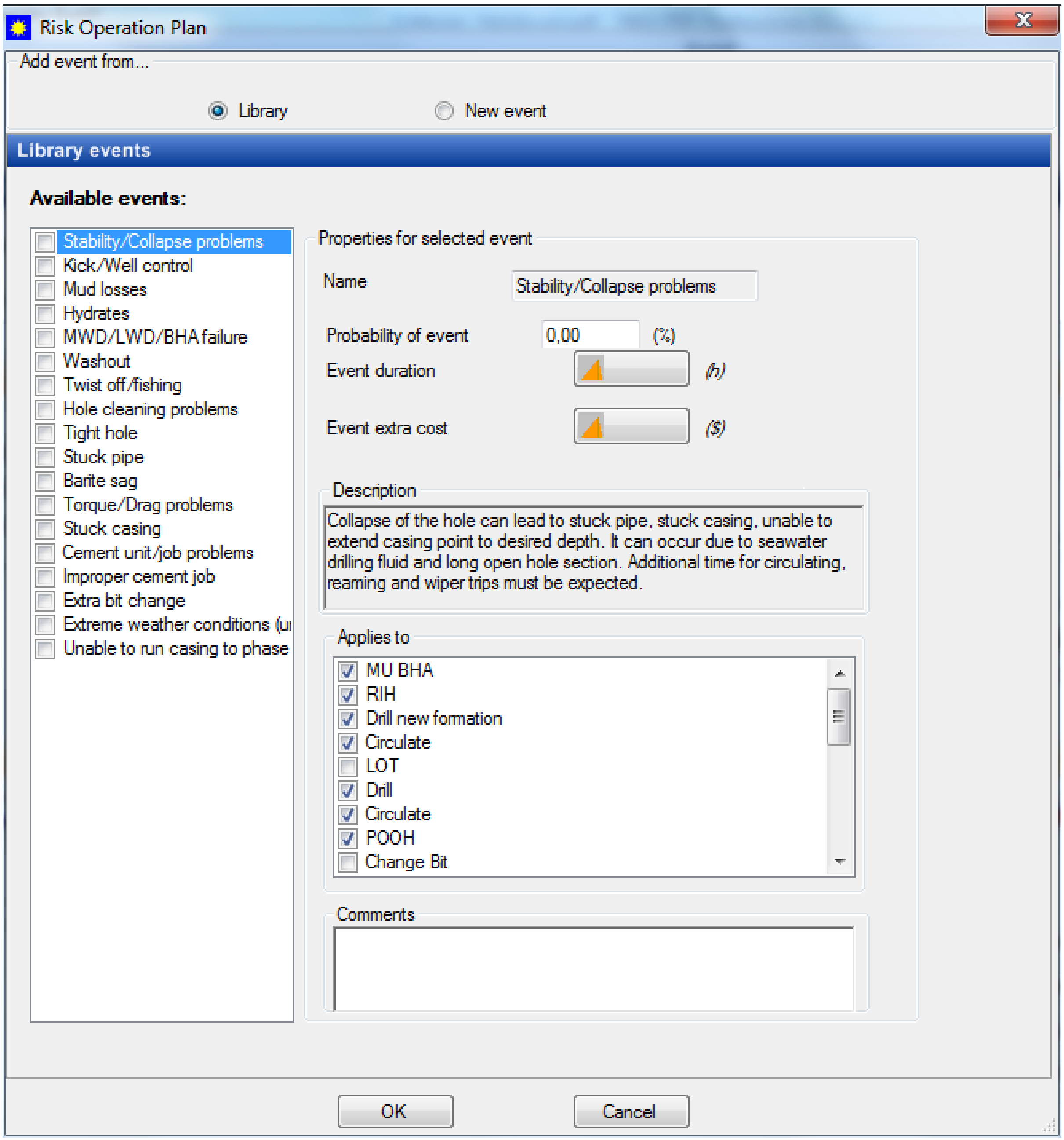

Figure 19.- Input panel for Drilling phase in phase level. taken from Risk€.

6 Simulation

This chapter describes the procedure adopted in the simulation and how the input data was arranged in order to work properly with the simulator. The well cost simulator used was Risk€ and the input data used was taken from EGS Well Construction Technology Evaluation Report (Polsky et al, 2008). This EGS technology report proposed a deep geothermal baseline well located in Clear Lake, California, with the feature of having an upper sedimentary layer of approx. 1000 m and below is the fractured igneous formations which is similar to the formation found in Soultz-sous-Forêts, France.

6.1 Input Data

The input data for the simulator was taken from Polsky et al (2008), in collaboration with Thermasource Inc., who provided a detailed budget for an EGS well of approx. 6000 m depth (20000 feet). For better understanding of the detailed cost rates, more explanation is provided in Appendix, with the purpose of introducing Risk€ easily.

The optimal EGS geological environment is a high geothermal gradient with proper permeability and porosity with satisfy communication between the injection wells and the production wells, so that heat exchange from the injected water to the reservoir formation can be guaranteed (Tester et al, 2006). Fracture zones especially at reservoir depth are also expected. For low permeability formations, after drilling the well to assure useful temperature, a large heat transfer surface must be created by hydraulically fracturing the rock and with the requirement that these fractures will be connected to the production well.

The most representative input parameters of the simulator will be discussed, and at the end of this chapter an input summary will be displayed for presenting the complete data.

6.1.1 Well diagram

As shown in the previous chapter, the first recommended interface to work with is the well architecture panel, where Figure 22 is used as input basis. As seen in Figure 20, all the casings are cemented to surface, with this case having a tie back for completing the cementing job. The input interface does not ask for uncertainties in this level because it is assumed that the drilling phases' objectives will be accomplished. Also this well cost analysis does not consider perforation, completion and stimulation jobs. The project focus is on the drilling operations required to reach the objective depth.

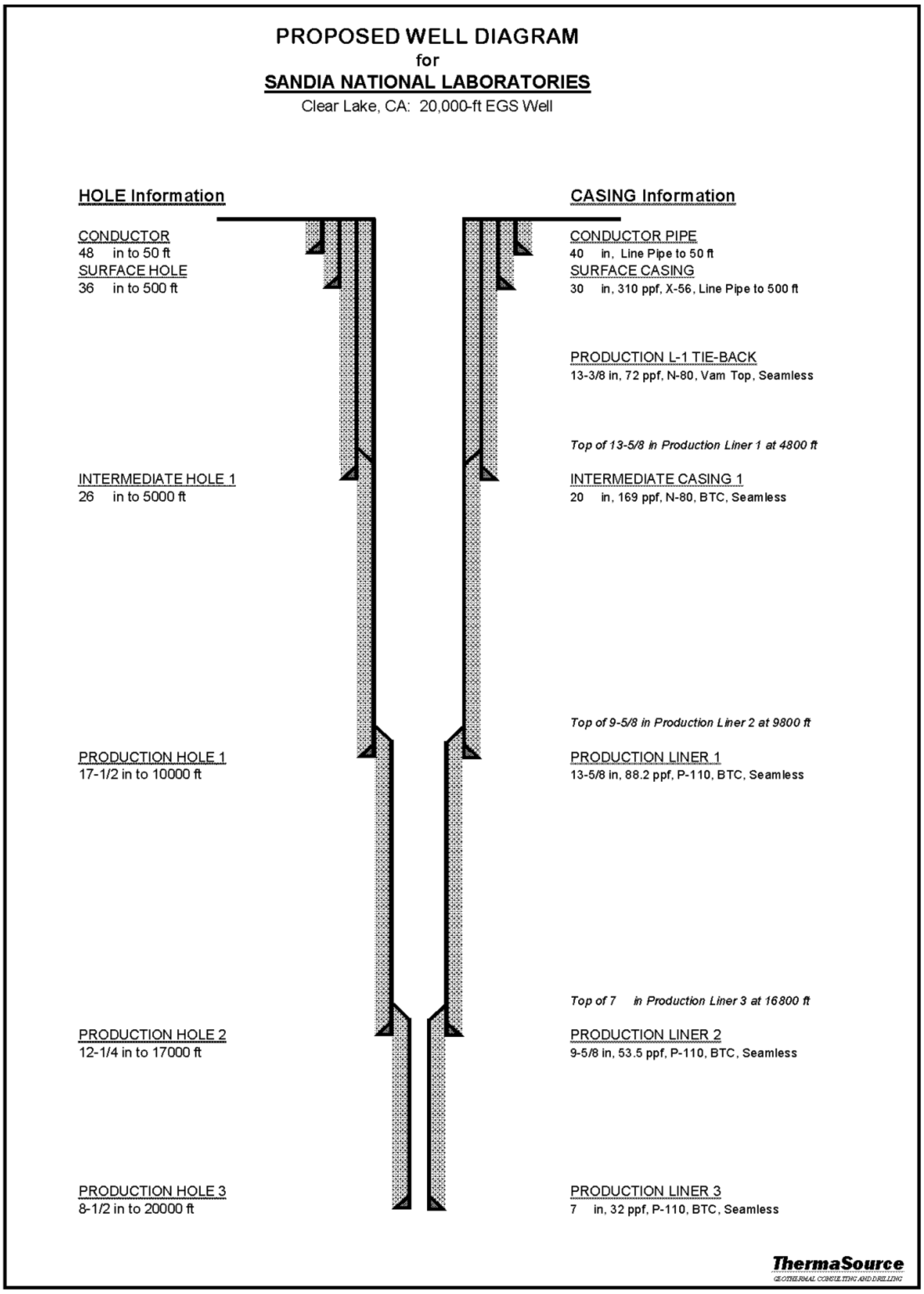

Figure 20.- Proposed Well diagram. Taken from Polsky et al (2008)

6.1.2 ROP

The bibliography that provided the costs and time for the simulation did not explained the exact lithology of the formations drilled, even though they mentioned that the expected rocks had the characteristics of being abrasive and hard such as granite, that is the case of Soultz-sous-Forêts (France). During the granitic section drilling, in Soultz, the ROP vary between 2 m/h and 10 m/h with an average between 3 and 4 m/h. In the upper part of the granite (1420-

2900m) there is a good correlation between high ROP values and fracture occurrences (Dezayes et al, 2005b; Baumgartner et al, 1999).

6.1.3 Drilling Fluid Volumes

Time and materials for lost circulation treatment can represent 15% of well cost, and the underpressured formation aggravates differential sticking, so these can be major impacts on drilling cost (Finger & Blankenship, 2010). The main reason behind this possible event is that the best environment for geothermal exploration is fractured lithology, were even hard rocks with low natural porosity can increase their permeability for proper fluid interaction between injector and production wells. For this reason the expected fluid losses on the superficial section are “fewer” than the other sections.

6.1.4 Spread Rate

This parameter is dominant in determining the simulation’s uncertainty. Luckily the provided data from Polsky et al (2008) is very accurate in many variables and is possible to calculate some input parameters such as Spread rate.

The spread rate was calculated with the time dependent cost rates of cementing services, drilling services like top drive, directional drilling services, etc., it has to be noticed that all these services personnel is also accounted for the spread rate. Expendables like fuel are also considered. For better understanding of the costs considered it is recommended to review the Appendix part of this thesis.

For calculating the spread rate uncertainty every parameter of it had to be analyzed individually, to confirm the minimum, maximum and peak value. Then after selecting the fixed values on the spread rate, like personnel and most of the well services, and choosing the variable costs, such as rig welding, air drilling services and fuel, the total spread rate is calculated by simply summing the minimum values of all these parameters and then summing the maximum values. This final result is constant through all the phases.

In the case of Rig rate the daily cost does not vary as much as expected because of its high certainty on it. It is usual to have rig rate as non-variable cost on land rig budget calculation.

6.1.5 RIH and POOH

For these two variables, both were assumed to have a constant velocity of 300 m/h, nevertheless when the bit drillstring is still present on the drilled hole, the movement is slower compared to when the drill string is passing through the "old hole" or cased hole. That is the reason for having a probability distribution instead of a single point value. When the tool is POOH the drillstring speed is slower than RIH because the tool must be prevented from getting entrapped in the drilled formation.

6.1.6 Input Data Summary

Table 2. *Drilling/Circulation and Bit Parameters input data*

Drilling Phase

Drilling/Circulation and Bit Parameters

Parameter	Distribution type	Minimum	Peak/Mean	Maximum
ROP(m/hr) - 36" section	Triangle	1,10	3,60	6,00
ROP(m/hr) - 26" section	Triangle	2,67	4,57	6,30
ROP(m/hr) - 17 1/2" section	Triangle	2,60	3,25	4,55
ROP(m/hr) - 12 1/4" section	Triangle	1,15	1,82	3,00
ROP(m/hr) - 8 1/2" section	Triangle	1,11	1,90	2,64
Bit cost($) - 36" section	Uniform	60.000,00	-	100.000,00
Bit cost($) - 26" section	Uniform	65.000,00	-	105.000,00
Bit cost($) - 17 1/2" section	Uniform	35.000,00	-	65.000,00
Bit cost($) - 12 1/4" section	Uniform	18.000,00	-	32.000,00
Bit cost($) - 8 1/2" section	Uniform	12.000,00	-	20.000,00
Bit Change(hr)	Uniform	3,00	-	5,00
Circulation time(hr) - 36" section	Uniform	0,50	-	1,50
Circulation time(hr) - 26" section	Uniform	0,75	-	1,50
Circulation time(hr) - 17 1/2" section	Uniform	1,00	-	3,00
Circulation time(hr) - 12 1/4" section	Uniform	2,00	-	4,00
Circulation time(hr) - 8 1/2" section	Uniform	3,00	-	5,00
Expected losses(m^3) - 36" section	Triangle	60,00	125,00	145,00
Expected losses(m^3) - 26" section	Triangle	600,00	1.550,00	1.800,00
Expected losses(m^3) - 17 1/2" section	Triangle	100,00	350,00	420,00
Expected losses(m^3) - 12 1/4" section	Triangle	70,00	168,00	190,00
Expected losses(m^3) - 8 1/2" section	Triangle	0,00	5,00	100,00
Fluid Cost($/$m^3$) - 36" section	Uniform	29,00	-	59,00
Fluid Cost($/$m^3$) - 26" section	Triangle	42,00	63,00	84,00
Fluid Cost($/$m^3$) - 17 1/2" section	Triangle	62,00	93,00	124,00
Fluid Cost($/$m^3$) - 12 1/4" section	Triangle	89,00	133,00	177,00
Fluid Cost($/$m^3$) - 8 1/2" section	Triangle	107,00	160,00	214,00

Table 2 *Continued*

Waste Treatment($) - 36" section	Uniform	13.000,00	-	17.000,00
Waste Treatment($) - 26" section	Uniform	47.000,00	-	52.000,00
Waste Treatment($) - 17 1/2" section	Uniform	50.000,00	-	56.000,00
Waste Treatment($) - 12 1/4" section	Uniform	88.000,00	-	96.000,00
Waste Treatment($) - 8 1/2" section	Uniform	89.000,00	-	97.000,00

Table 3. *Drillpipe/BHA and Tripping Speeds input data.*

Drillpipe/BHA and Tripping Speeds

Parameter	Distribution type	Minimum	Peak/Mean	Maximum
MU BHA(hr) - All sections	Uniform	5,00	-	7,00
RIH(m/h) - All sections	Triangle	280,00	300,00	310,00
POOH(m/h) - All sections	Triangle	200,00	300,00	310,00
Break BHA(hr)	Single	-	8,00	-

Table 4. *Casing and Cementing input data*

Casing and Cementing

Run casing or liner

Parameter	Distribution type	Minimum	Peak/Mean	Maximum
Accessories($) - 36" section	Uniform	23.000,00	-	27.000,00
Accessories($) - 26" section	Uniform	54.000,00	-	60.000,00
Accessories($) - 17 1/2" section	Uniform	43.000,00	-	47.000,00
Accessories($) - 12 1/4" section	Uniform	32.500,00	-	37.500,00
Accessories($) - 8 1/2" section	Uniform	23.000,00	-	27.000,00
Casing cost($/m) - 36" section	Single	-	984,00	-
Casing cost($/m) - 26" section	Single	-	623,00	-
Casing cost($/m) - 17 1/2" section	Single	-	709,00	-
Casing cost($/m) - 12 1/4" section	Single	-	322,00	-
Casing cost($/m) - 8 1/2" section	Single	-	223,00	-
Casing cost($/m) - Tie back section	Single	-	771,00	-
Casing services($) - 36" section	Uniform	9.700,00	-	13.700,00
Casing services($) - 26" section	Uniform	9.700,00	-	13.700,00
Casing services($) - 17 1/2" section	Uniform	9.700,00	-	13.700,00
Casing services($) - 12 1/4" section	Uniform	9.700,00	-	13.700,00
Casing services($) - 8 1/2" section	Uniform	9.700,00	-	13.700,00
Casing services($) - Tie back section	Uniform	9.700,00	-	13.700,00

Table 4 *Continued*

Cementing				
Duration(hr) - 36" section	Uniform	23,00	-	27,00
Duration(hr) - 26" section	Uniform	35,50	-	38,50
Duration(hr) - 17 1/2" section	Uniform	39,00	-	45,00
Duration(hr) - 12 1/4" section	Uniform	42,50	-	49,50
Duration(hr) - 8 1/2" section	Uniform	59,00	-	68,00
Duration(hr) - Tie back section	Uniform	22,00	-	26,00
Cement Volume(m^3) - 36" section	Triangle	45,00	52,00	61,00
Cement Volume(m^3) - 26" section	Triangle	310,00	323,00	335,00
Cement Volume(m^3) - 17 1/2" section	Triangle	144,00	150,00	158,00
Cement Volume(m^3) - 12 1/4" section	Triangle	90,00	95,00	101,00
Cement Volume(m^3) - 8 1/2" section	Triangle	17,00	18,28	19,40
Cement Volume(m^3) - Tie back section	Triangle	148,00	154,00	161,00
Cement Slurry cost($/m^3$) - 36" section	Single	-	3.963,00	-
Cement Slurry cost($/m^3$) - 26" section	Single	-	3.742,00	-
Cement Slurry cost($/m^3$) - 17 1/2" section	Single	-	4.780,00	-
Cement Slurry cost($/m^3$) - 12 1/4" section	Single	-	5.787,00	-
Cement Slurry cost($/m^3$) - 8 1/2" section	Single	-	18.429,00	-
Cement Slurry cost($/m^3$) - Tie back section	Single	-	4.151,00	-

Table 5. *Additional Cost input data*

Additional Cost

LOT - All sections except 36" & Tie back				
New formation(m)	Single	-	3,05	-
Duration(hr)	Uniform	2,00	-	4,00
Log				
Duration(hr) - 36" section	Uniform	6,00	-	8,00
Duration(hr) - 26" section	Uniform	30,00	-	39,00
Duration(hr) - 17 1/2" section	Uniform	51,50	-	69,00
Duration(hr) - 12 1/4" section	Uniform	85,00	-	111,00
Duration(hr) - 8 1/2" section	Uniform	100,00	-	130,00
Log Cost($) - All sections except tie back	Uniform	115.000,00	-	135.000,00

Table 6.*General Costs input data*

General Costs

Parameter	Distribution type	Minimum	Peak/Mean	Maximum
Rig rate($/day)	Uniform	26.000,00	-	30.000,00
Spread rate($/day)	Triangle	18.038,00	21.702,00	55.365,00
Drillstring/BHA cost($/day)	Triangle	7.000,00	9.000,00	22.000,00
Wellhead cost($) - 36" section	Single	-	20.000,00	-
Wellhead cost($) - 26" section	Single	-	15.000,00	-
Wellhead cost($) - 17 1/2" section	Single	-	0,00	-
Wellhead cost($) - 12 1/4" section	Single	-	0,00	-
Wellhead cost($) - 8 1/2" section*	Single	-	128.000,00*	-
Wellhead cost($) - Tie back section	Single	-	10.000,00	-
Fixed cost($) - 36" section	Single	-	9.303,00	-
Fixed cost($) - 26" section	Single	-	28.633,00	-
Fixed cost($) - 17 1/2" section	Single	-	30.442,00	-
Fixed cost($) - 12 1/4" section	Single	-	53.131,00	-
Fixed cost($) - 8 1/2" section	Single	-	41.605,00	-
Fixed cost($) - Tie back section	Single	-	11.887,00	-
Support cost($) - All sections	Triangle	3.500,00	4.500,00	9.400,00

Table 6. *BOP editor input data*

BOP

Parameter	Distribution type	Minimum	Peak/Mean	Maximum
Nipple up(hr) - 30" BOP	Triangle	30,00	44,00	55,00
Nipple up(hr) - 20" BOP	Triangle	34,00	49,00	68,00
Pressure Test(hr) - 30" BOP	Uniform	3,00	-	4,00
Pressure Test(hr) - 20" BOP	Uniform	7,00	-	13,00
Rig rate($/day)	Uniform	26.000,00	-	30.000,00
Spread rate($/day)	Triangle	18.038,00	21.702,00	55.365,00
Drillstring/BHA cost($/day)	Triangle	7.000,00	9.000,00	22.000,00
Fixed cost($) - Both sections	Single	-	6.500,00	-
Support cost($) - Both sections	Triangle	3.500,00	4.500,00	9.400,00

NOTE: The wellhead cost for the 8 ½” section it does not imply the wellhead cost, tis variable was used for representing the next production equipment costs: Master valves ($ 70000), Wing valves ($ 12000), Nuts, Studs, Flanges and Gages ($ 10000), Wellhead Welding and Installation services ($ 36000).

6.1.7 Risk Events

Now with the standard operational plan defined it is viable to understand the possible undesired events that influence the final result. The values provided on this table are the overall of the probability distribution used on Risk€. The distribution used was in accordance to bibliography and oil & gas experience, any deep geothermal experience is not available due to few wells drilled around the globe.

Table 7. *Input data summary for Risk Operational Plan*

		OPERATIONAL PHASE						
		36"	26"	17 1/2"	12 1/4"	8 1/2"	BOP 30"	BOP 20"
STUCK PIPE	*Cost*	-	185.000	231.666	275.000	315.000	-	-
	Duration	-	37	43	46	36	-	-
	Probability	-	20	20	20	20	-	-
WELLBORE INSTABILITY	*Cost*	2.367	45.251	81.133	100.316	113.500	-	-
	Duration	4	5	6	7	7	-	-
	Probability	15	15	15	20	15	-	-
DIFFICULT CEMENT JOBS	*Cost*	-	35.000	67.500	132.870	165.000	-	-
	Duration	-	6	7	11	13	-	-
	Probability	-	15	15	20	25	-	-
SHALLOW WATER	*Cost*	122	-	-	-	-	-	-
	Duration	3	-	-	-	-	-	-
	Probability	20	-	-	-	-	-	-
WASHOUT	*Cost*	1.850	915	1.240	3.990	-	-	-
	Duration	2	3	4	5	7	-	-
	Probability	10	8	8	8	8	-	-
EXTRA BIT	*Cost*	-	80.000	90.000	27.000	26.500	-	-
	Duration	-	7	12	18	22	-	-
	Probability	-	85	85	95	95	-	-
STUCK CASING	*Cost*	-	-	-	-	-	-	-
	Duration	-	-	32	35	45	-	-
	Probability	-	-	5	5	5	-	-
BOP EQUIPMENT	*Cost*	-	-	-	-	-	850	850
	Duration	-	-	-	-	-	4	4
	Probability	-	-	-	-	-	2	2

NOTE:

- The probability of having wellbore instability on the 12 1/4" section increases because is a longer section and the presence of fractured granite is possible.

- The probability for having an improper cementing job increases with depth because the complete drilling section has to be cemented until the slurry reaches surface.

- The chances for having stuck casing are null in the first two sections because of their shallow depth.

- The Tieback section is supposed to be run without risk events going on because the casing's way until reaching the objective depth is cased already.

6.2 Procedure of the Simulation

To begin the simulation, the well architecture is introduced as seen in the input panel shown in the Risk€ description placed in the previous chapter.

The next step is to introduce all the mentioned variables in the simulator with their proper uncertainties, choosing the probability distribution type as mentioned in the previous sections.

With all the input data introduced correctly and after reviewing if each of the values has logic behind it, and also understanding how the simulator works and the dependence of some variables on others, the simulation is run. The simulator does not take too much time, so it is possible to simulate as much as needed.

Playing with the variables while doing the simulation is good to understand the simulator and identify beforehand which variables affect the simulation more than others, by simply checking how the mean duration and mean cost is varying as the input data is filled.

6.2.1 Operational Plan Generated by the Simulator

The software needs to generated operations using the introduced input data. Risk€ is able to generate a standard operation plan according to the availability of the input data and the selected drilling phases. In this particular simulation only drilling phases and BOP installation phases were considered as relevant.

The operation plan generated sometimes does not describe the actual operations needed at a specific time; therefore it is possible to edit this operation plan while introducing the data. For this added event it is required to state the respective extra duration and extra costs and the place in the operation plan timeline. Even though it has to be understood that all the extra events with their proper extra costs and time are simply added to the final result of the respective phase, for calculating the final well cost.

The standard operational plan generated by Risk€ for the presented simulation had the following characteristics showed in Figures 21 and 22, where some sub-operations were repetitive and therefore for easy comprehension these processes were pointed out with a repetition index.

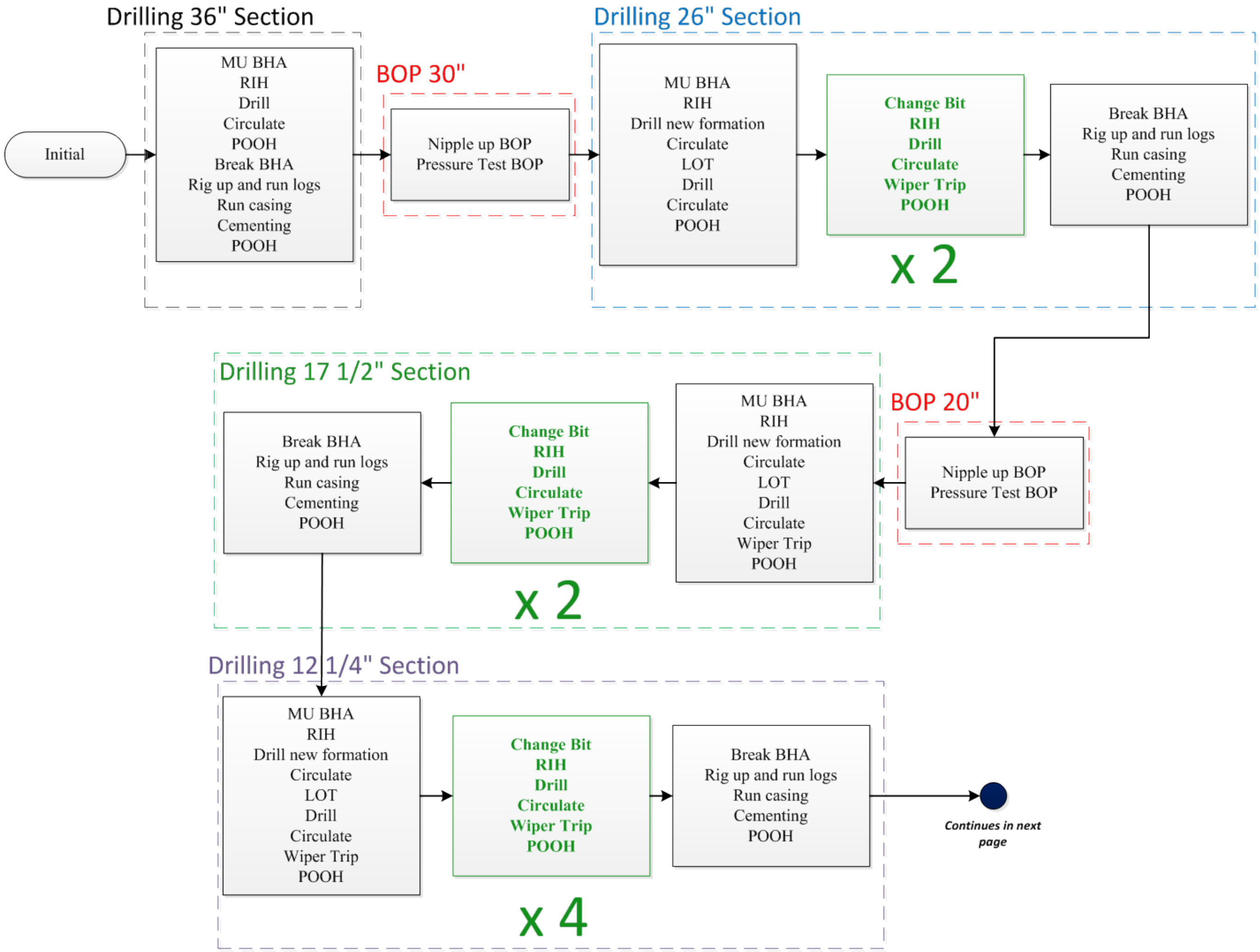

Figure 21.- Flux Diagram for the Operational Plan.

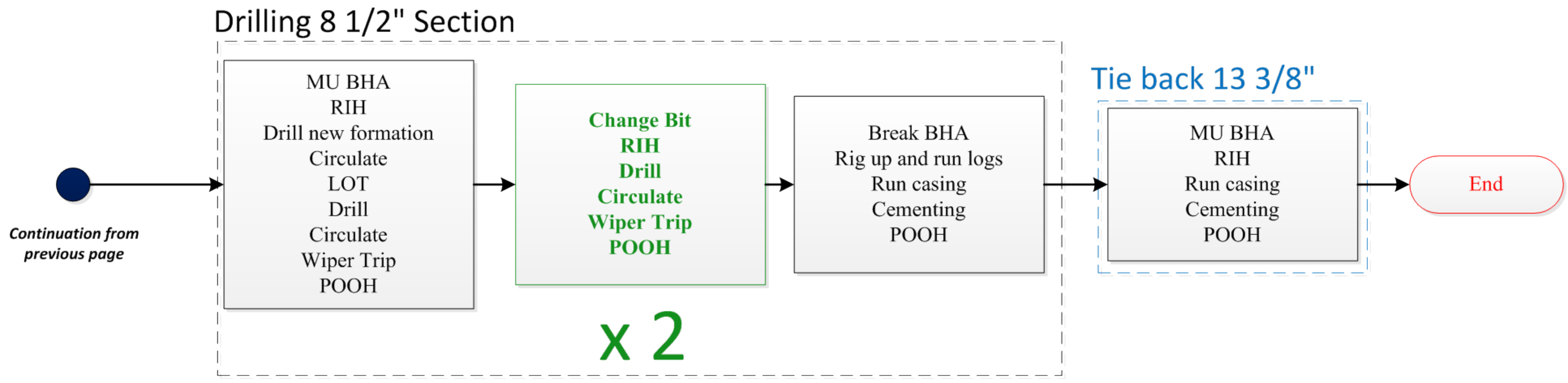

Figure 22.- Continuation of the flux diagram for the Operational Plan

NOTE: Cleaning out the well means to clean BHA and laying down time of equipment

6.3 Presentation of Results

After running the simulation, the simulator provides four types of results (Loberg et al, 2008b):

6.3.1 Operational Plan and Risk Operational Plan

For the Operation plan, the results displayed are related to the operation plan of the selected alternative, which in this simulation is one. Any events added to the risk operation plan node will not be included in these results.

In the case of risk operational plan, the results here include the standard operation plan and any events added. The display form of both simulations have the same form, even though their results are different, as shown in Figure 23.

6.3.1.1 Well Summary

The well summary comprises three sections within the results, as seen in Figure 23.

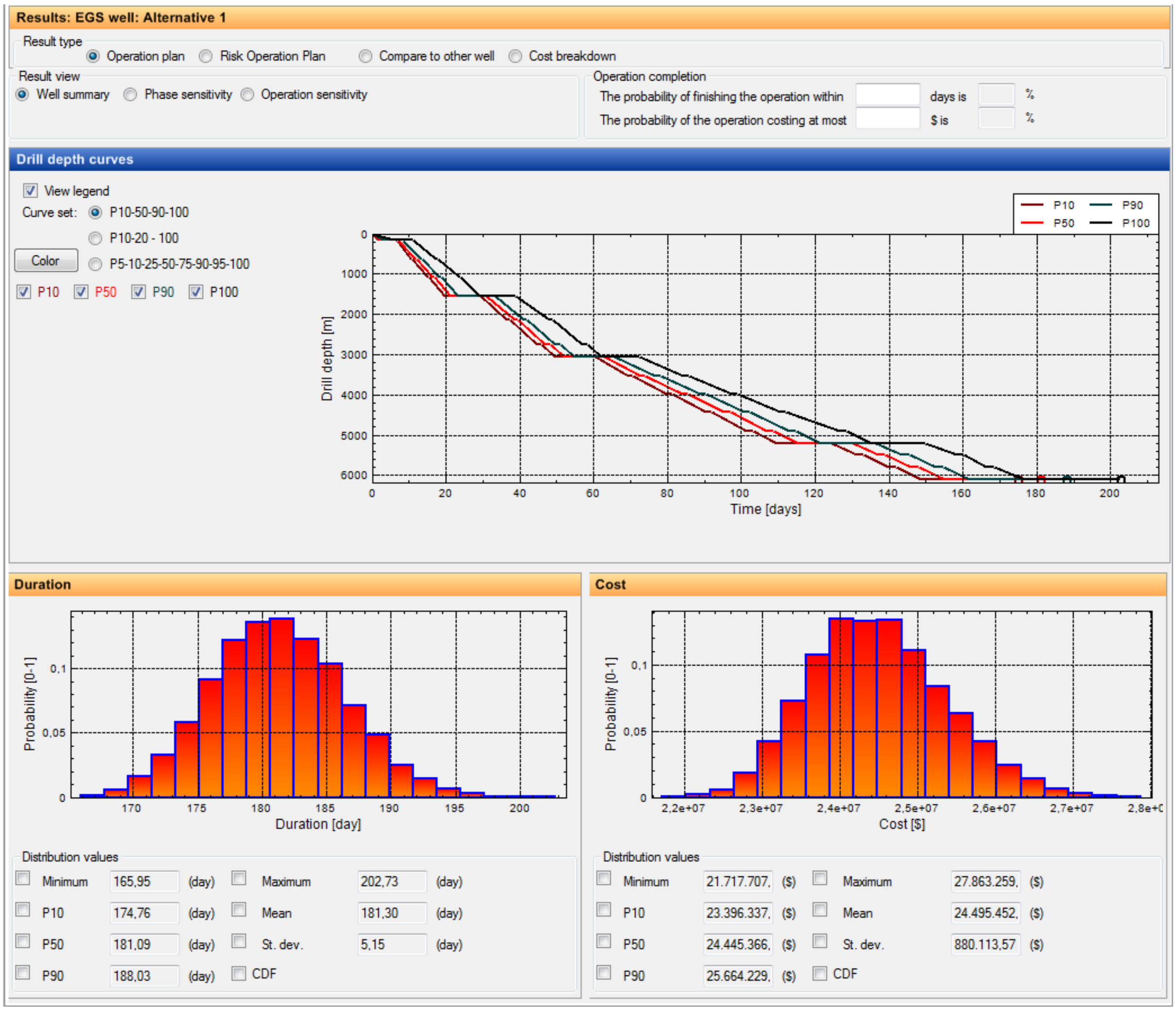

Figure 23.- Well summary result from standard operation plan. Taken from Risk€.

Figure 21 displays the "drill depth curves" that are shown with different percentile curves for drill depth versus time. The next section below, histograms shows total duration and cost for the well, with the values of minimum, maximum, mean, P10, P50, P90, standard deviation and the cumulative distribution function (CDF), by selecting them.

6.3.1.2 Phase Sensitivity

The phase assessment consists of two choices:

- Sensitivity Measure 1: Each phase's cost (left) and duration (right) are displayed as proportions of the total cost and duration for the operation plan, respectively. The precise calculation of this value is made by taking the proportion of the phase contribution in relation to the total for each simulation, and finally calculating the mean of this resulting distribution.

- Sensitivity Measure 2: Displays the correlation coefficient of the phase cost and standard operation plan total cost to the left, and the correlation coefficient of phase duration and standard operation plan total duration to the right. The correlation coefficient shows the strength and direction of the linear relationship between a phase's cost/duration and total cost/duration of the standard operation plan. The display form for this second sensitivity measure has the same characteristics as the first one, as demonstrated in Figure 22.

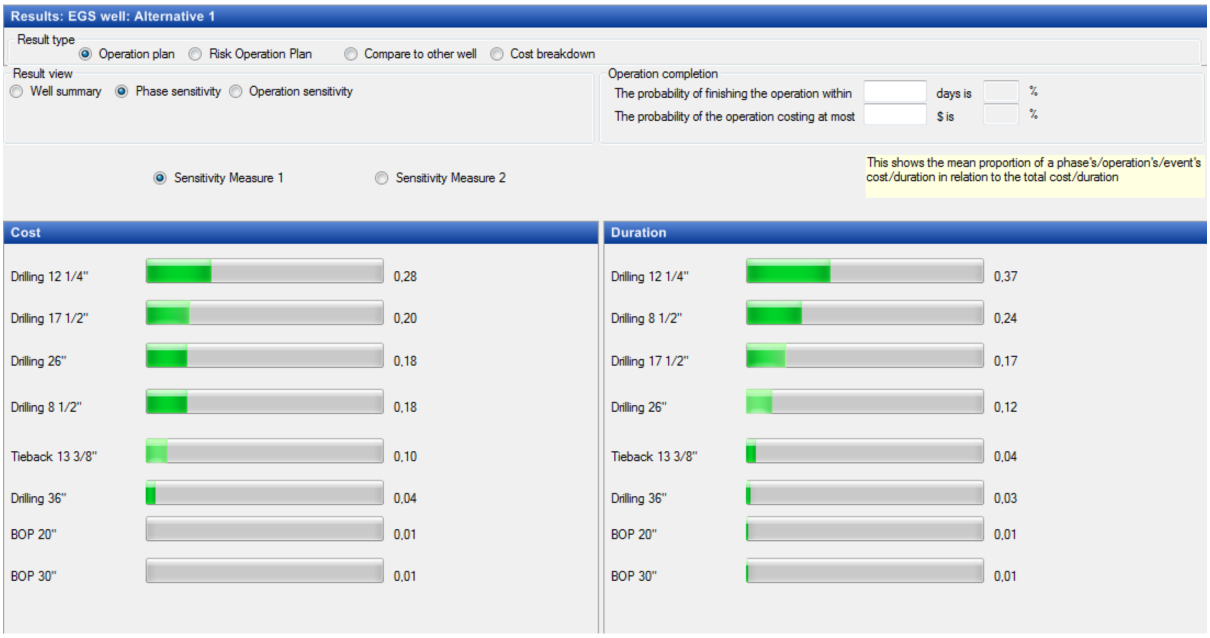

Figure 24.- Example of the cost and duration contributions on phase level. Taken from Risk€.

6.3.1.3 Operation Sensitivity

In the previous section, the phase sensitivity was conducted to study the contribution and the relationship between phases and total cost and duration. Now the operation sensitivity studies the same patterns, but instead of phase's cost and duration, operation's cost and duration are analyzed with sensitivity measure 1 and sensitivity measure 2.

6.3.2 Compare to other well

This type of analysis will compare certain results (either based upon the standard operation plan or on the risk operation plan) between two well alternatives. It is also possible to compare the standard operation plan with the risk operation plan for one well alternative.

The results sections in the comparison are:

- Depth vs. time: This compares two well alternatives with respect to the expected drill depth versus time curve, i.e. the mean duration for each operation.
- Cost vs. time: Same as the first point, but instead of depth, cost is used .
- Duration: This compares two well alternatives with respect to the simulated total duration spread. It is thus equal to comparing the duration histograms from Operation plan or Risk operation plan result type for the alternatives. The duration histogram gives a picture of the range, spread and most likely duration for each alternative.
- Cost: Same as mentioned before, follows the comparison between two well cost alternatives.

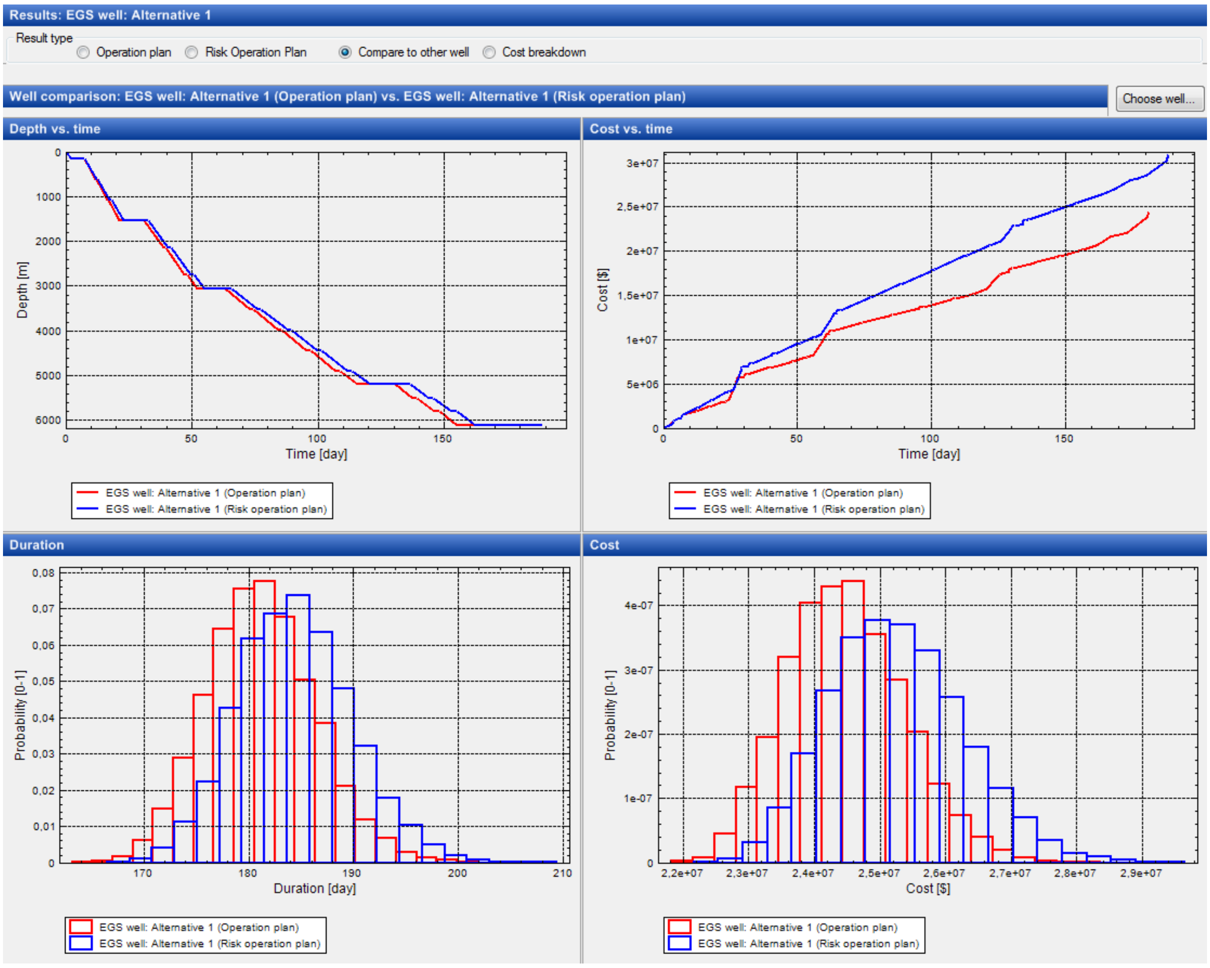

Figure 25.- Example of results comparison window. Taken from Risk€

6.3.3 Cost Breakdown

Figure 24 displays the cost for the selected alternatives' standard operation plan, broken down in different cost codes. The costs can be shown as a well total or for a selected phase. The subsequent figure represents the cost breakdown of the 12 ¼" Drilling Phase on its respective cost codes.

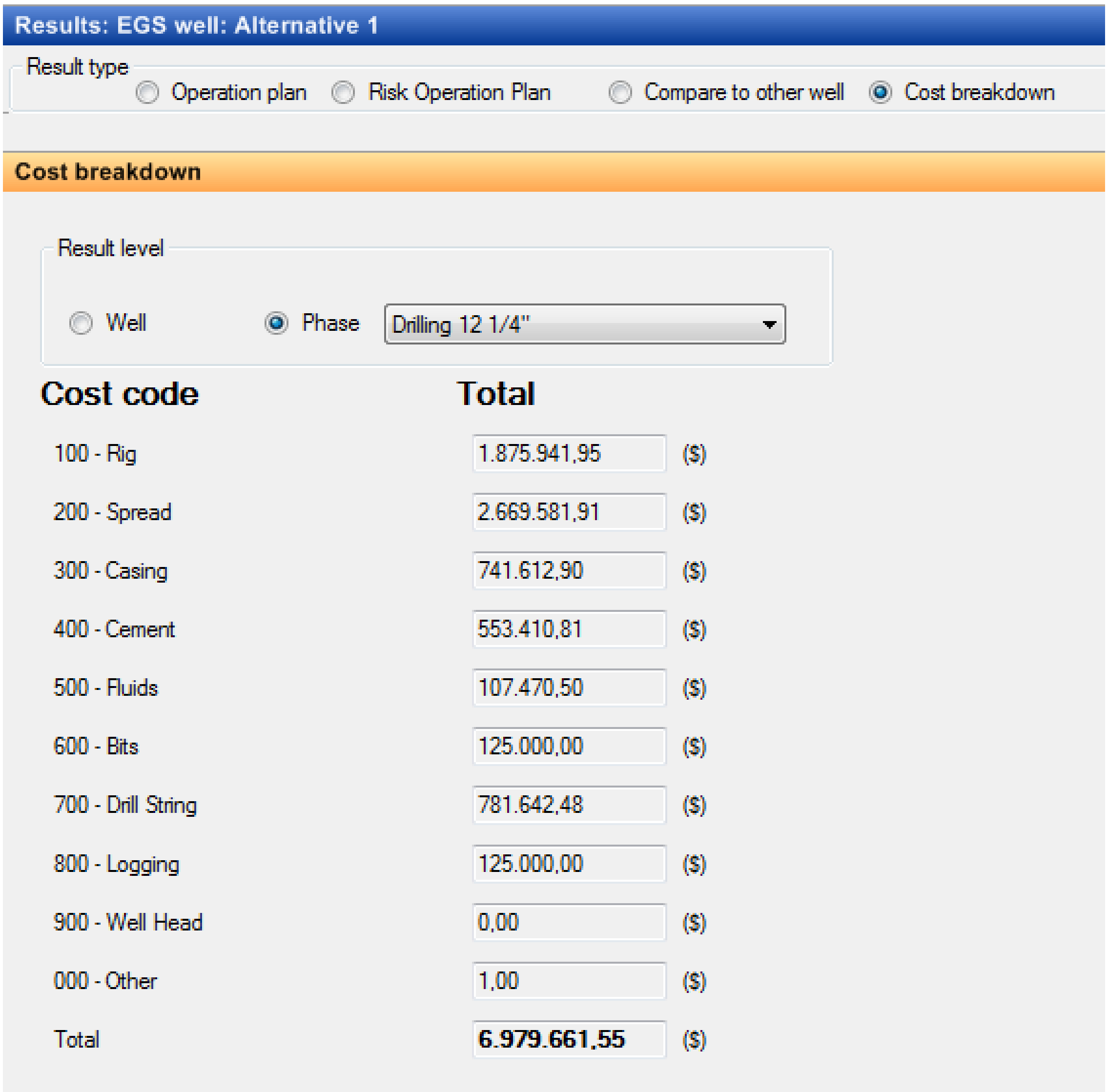

Figure 26.- Result view of cost breakdown. Taken from Risk€.

7 Discussion of Results

After reviewing the input data and the operational plan, the Monte Carlo simulation is performed and the next deterministic and probabilistic results are displayed, considering a scenario that followed the operation plan smoothly and also when the operational plan had risk events as possible happenings.

7.1 Results from Standard Operation Plan

As mentioned in the previous chapter, the results section from the simulator offers four options for showing the results to the user. The most important ones are the operational plan results and the risk operational plan outcome, which represents graphically the results.

The standard operational plan calculates the costs following exactly the flux diagram showed in Figure 21 & 22, later on the risk events are analyzed.

Before revising the main simulator's results, the deterministic view of the cost and duration without performing the simulation is checked for having an overall idea.

7.1.1 **Deterministic View**

The deterministic view gives results based on expected values found on the input data's probability distributions.

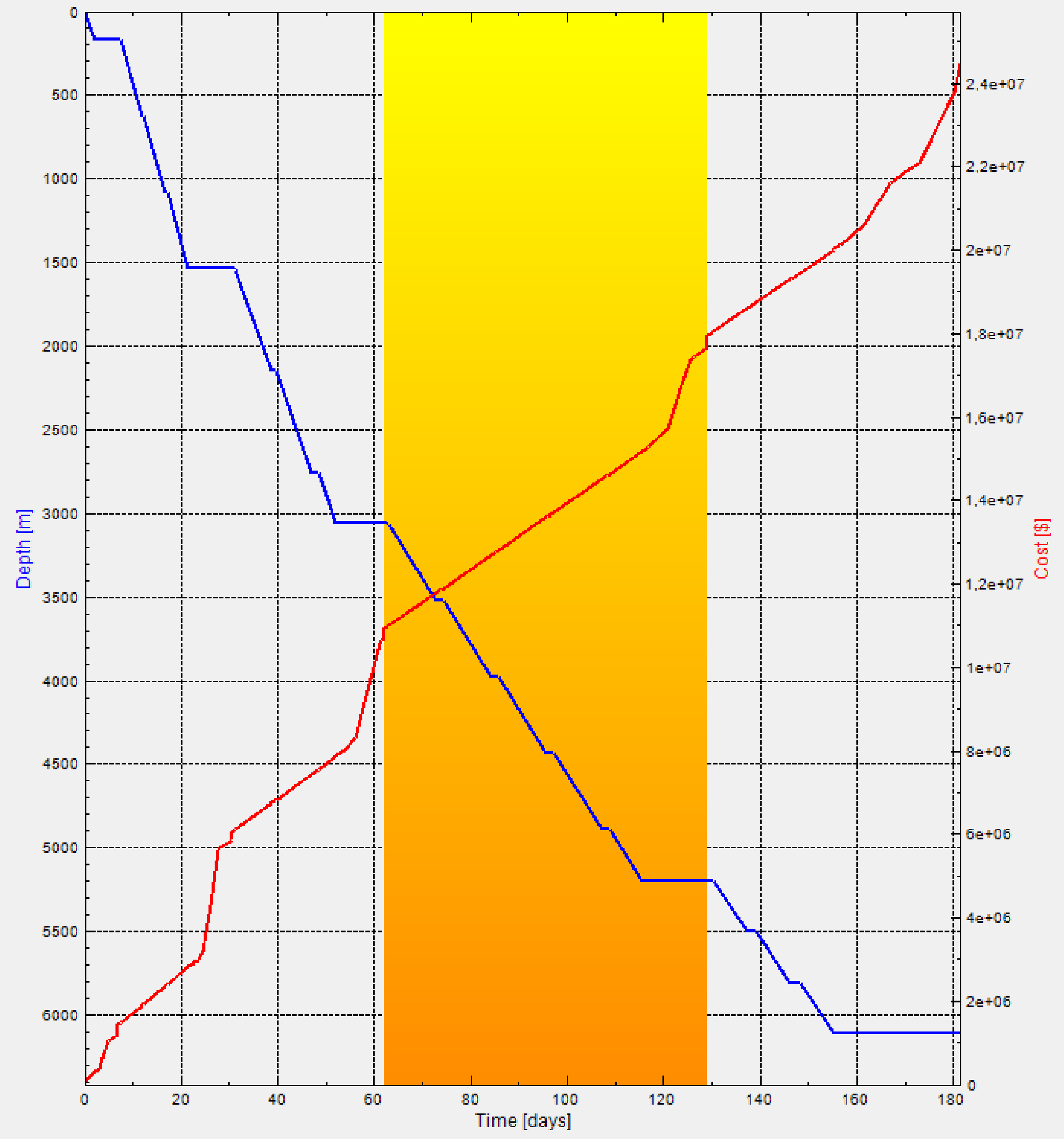

Figure 27.- Deterministic view from the result of the standard operation plan highlighting the 12 ¼ ” section. Taken from Risk€.

Figure 25 indicates that the most time consuming phase is the 12 ¼” drilling section. Later on with the phase sensitivity study it will be proved that the most costly phase is this one as well, pointing out the close relationship between time and cost.

From figure 36, the time-depth curve (the blue line) demonstrates that it takes 155.4 days to reach the TD of the well. By including circulation, tripping, breaking BHA time and the tie back it requires about 181.3 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 24.49 million USD is required, according to the deterministic well cost estimation.

7.1.2 **Probabilistic View**

For calculating the Monte Carlo Simulation it was chosen to perform 10,000 iterations instead of 100,000, which was the other option available. This section contains well summary, phase sensitivity and operational sensitivity result views representing the core of the simulator.

7.1.2.1 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 27 describes the possible scenarios for the time required to finish the well.

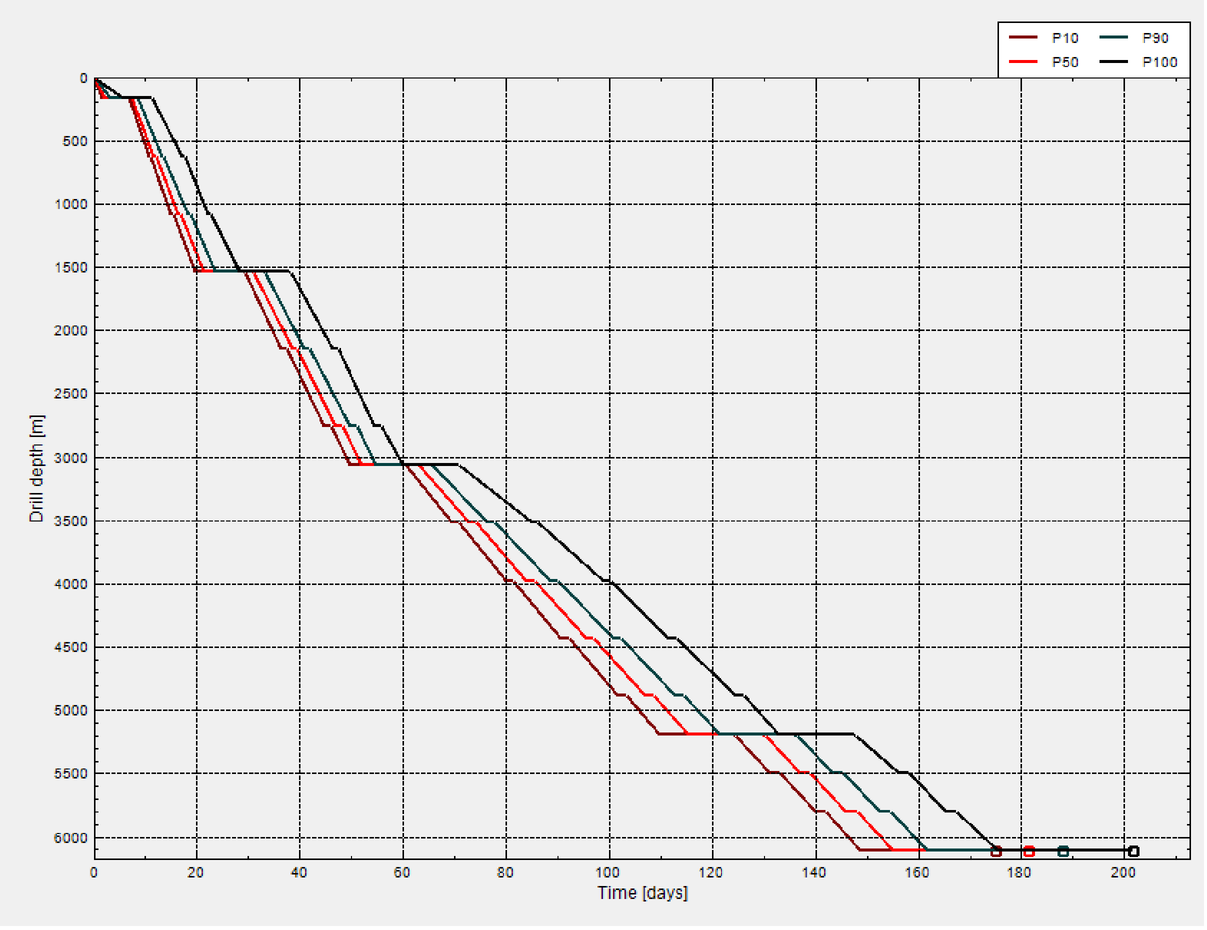

Figure 28.- Drill depth curves for the operational plan. Taken from Risk€.

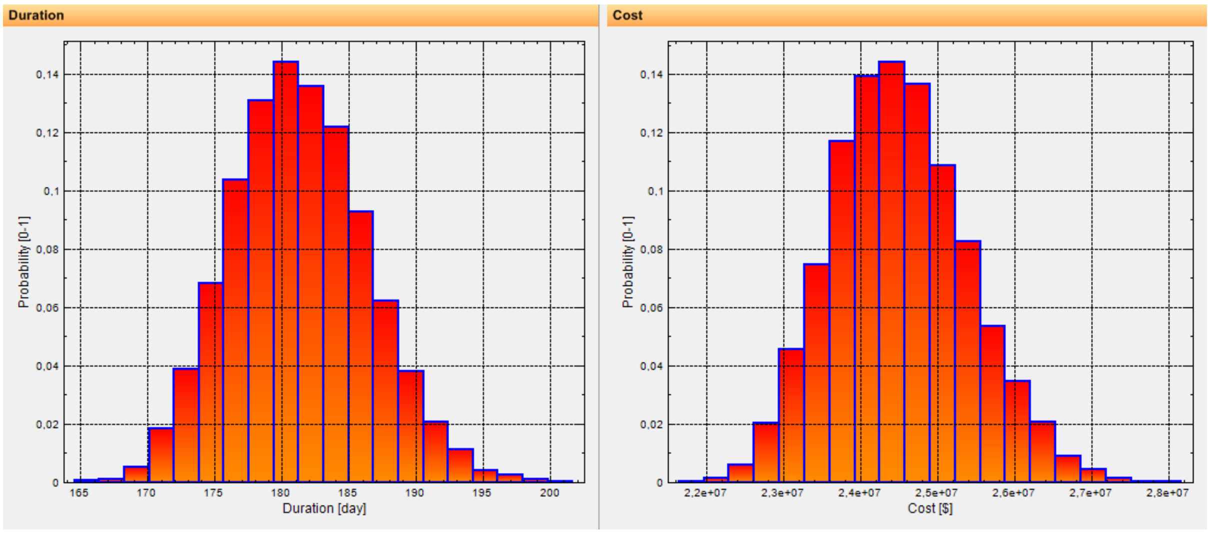

Figure 29.- Duration and Cost probability histogram. Taken from Risk€.

From Figures 23 & 28, the expected duration to drill this well is 181.30 days with the standard deviation of 5.15 days. An expected cost of this well is 24.49 million USD with the standard operation of 0.88 million USD. The well could be completed within 165.95 days the soonest and 202.73 days the latest. The budget required to drill this well could range from 21.72 – 27.86 million USD. The probability that the operation will be completed within 181.30 days is 51.5% and the probability that the operation will cost at most 24.49 million USD is 52.1%.

7.1.2.2 Phase Sensitivity

The main idea behind displaying these sensitivity results is to show which parameters of the simulation affect more the simulation's cost and duration.

The phase sensitivity 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.

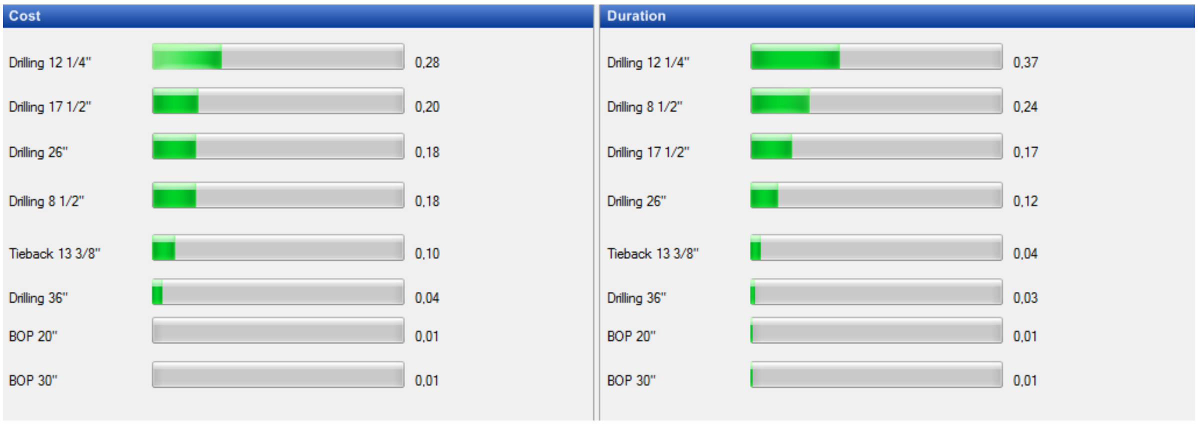

Figure 30.- Phase sensitivity from standard operation plan. Taken from Risk€.

The phase sensitivity analysis shows that drilling 12 ¼" section is the most sensitive phase compared to the other phases. It contributes for 28% of the total cost and 37% of the total duration. The reason behind this is the longer section to be drilled compared with the other sections, is not only the drilling that increases the costs, but also the casing and cementing operations.

Also Figure 29 shows that the BOP installation phases are not representative for the final cost, because of the few time consumed and few fixed costs involved. Drilling the 36" section involves not representative expenses as the other drilling phases, as shown by the previous figure.

By analyzing in depth this figure, it is possible to recognize that the main duration driver in the whole drilling project is the ROP, because of the position switch of the 8 ½" section from 2nd on the duration sensitivity to 4th on cost. A prove of this conclusion is shown on Table 2, where the ROP is the minimum among all drilling sections on the 8 ½" section

7.1.2.3 Operation Sensitivity

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

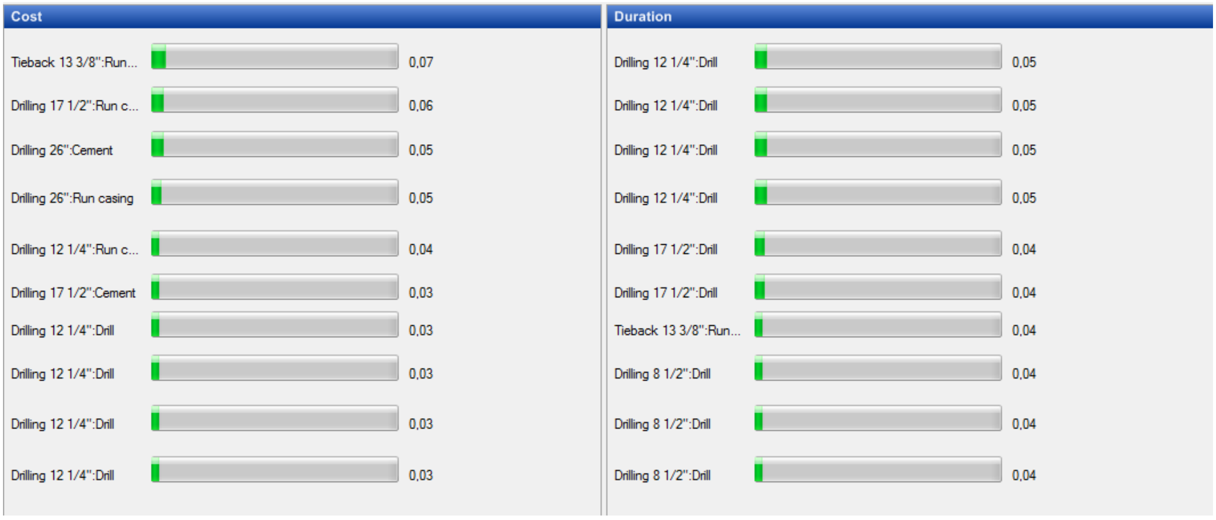

Figure 31.- Operation sensitivity from standard operation plan. Taken from Risk€.

Running the casing tieback cost is the most contributive sub operation because the running casing speed is reduced. Normally the time for running the casing is faster, but this input parameter represents the total time spent for running the casing, that includes RIH drillpipe, rig up and rig down casing running equipment, etc., besides running the casing, making a total overall time of 40 hours. The next most costly sub operation is to run the casing for the 17 ½" section that is also slow, consuming time and cost.

For the Duration sensitivity analysis the drilling sub operations domain the display, with the 12 ¼" section being more contributive because this section has an ROP as low as the 8 ½" but also is the longest section to drill, showing the reason why a change on this parameter will affect the complete project.

7.1.2.4 Cost Breakdown

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

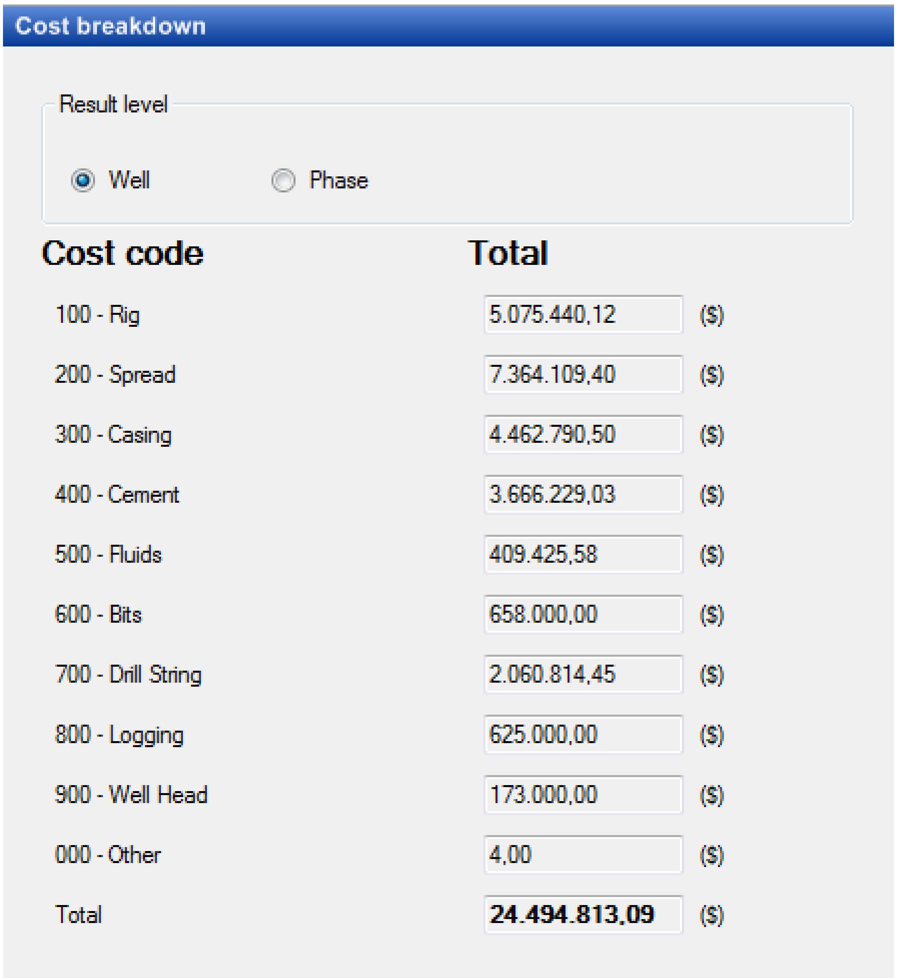

Figure 32.- Cost Breakdown of standard operation plan. Taken from Risk€.

In this particular case the main cost driver for the project is the spread rate, meaning that the services on the well are the ones affecting the most. It is responsible for 7.36 million USD from 24.49 million USD of total well cost or more than 30% of the well total cost. The second largest contribution is the Rig cost, showing 21% of the total cost. The cost of landrigs is not as expensive as other rigs offshore, showing a big difference with other well cost budgets. The common feature between these two cost categories is that both of them are dependent of time and represent 51% of the total cost, indicating that the time spent drilling affect the an EGS drilling project.

7.2 Results from Risked Operation Plan

In the previous point was described the results of the simulation counting without the potential risk events that will affect the model. Some of these events have the probability of occurring in any moment of the well construction, but others have a special singularity for each phase. All the risk events that have relevance for the simulation were described in chapter 4. In this chapter section the Risk operational plan results from the simulator are analyzed.

For understanding how the risk events added to the simulation affect the final results, the same analysis done for the standard operational is done with a comparison at the end of this point.

7.2.1 **Well Summary**

The corresponding time vs. depth curve for the risk events operational plan has a similar shape than the standard operational plan as shown in Figure 33.

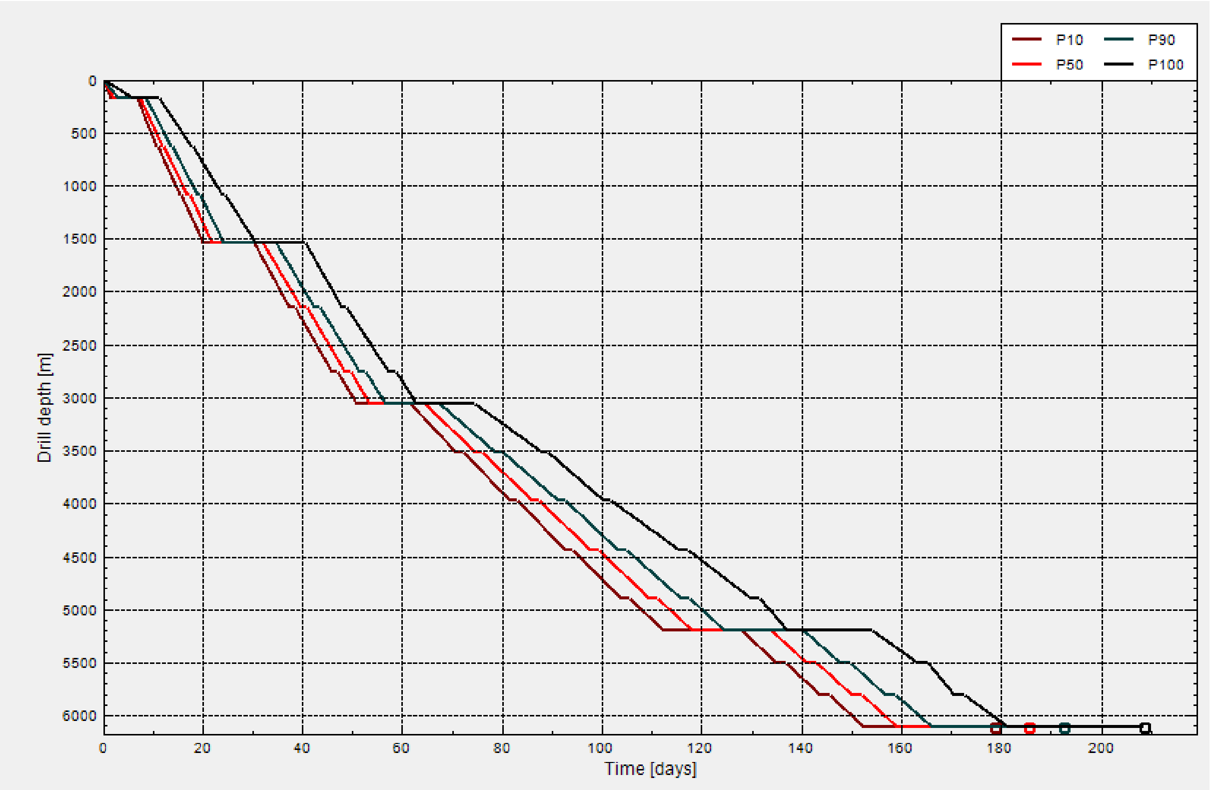

Figure 33.- Drill depth curves for the Risk operational plan. Taken from Risk€.

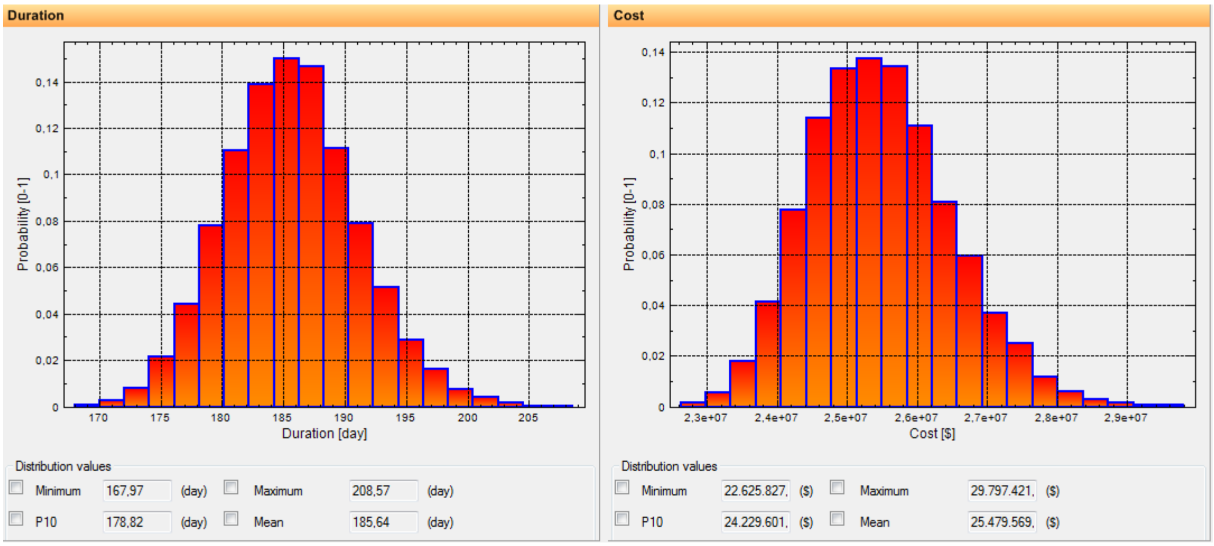

Figure 34.- Duration and Cost probability histogram for Risk operational Plan. Taken from Risk€.

From Figures 33, the expected duration to drill this well is 185.64 days with the standard deviation of 5.39 days. An expected cost of this well is 25.48 million USD with the standard operation of 1.01 million USD. The well could be completed within 167.97 days the soonest and 208.57 days the latest. The budget required to drill this well could range from 22.63 – 29.80 million USD. The probability that the operation will be completed within 185.64 days is 51.1% and the probability that the operation will cost at most 25.48 million USD is 52.3%.

7.2.2 Phase and Operation Sensitivity

The phase sensitivity analysis for the Risk operational plan shows the same first result as in the standard operational plan, which is to drill the 12 ¼” section. This means that the 12 ¼” section is influencing the most for the final well cost, including or not risk events. Also this result indicates that the risk events do not have as much domain as the low ROP on a drilling operation, especially when the drilling section is long.

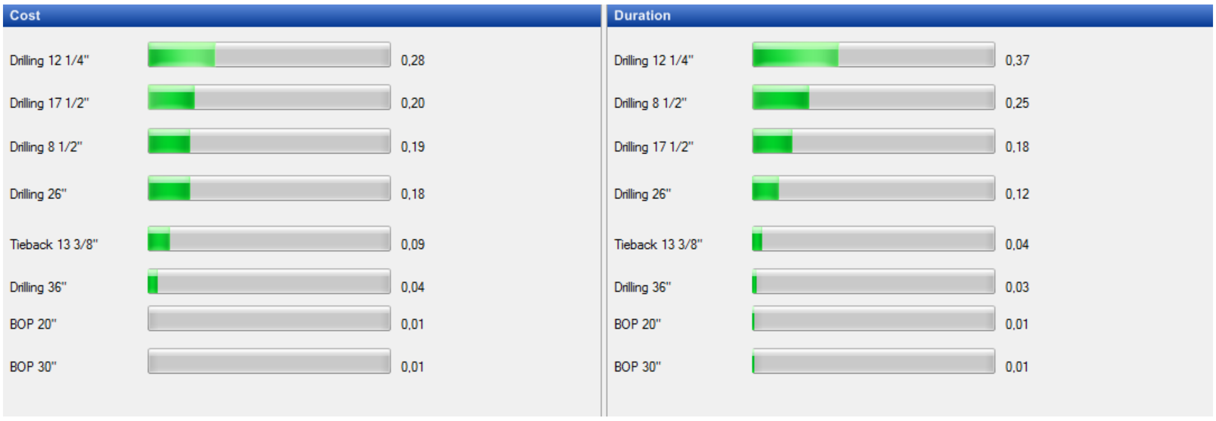

Figure 35.- Phase sensitivity from Risk operation plan. Taken from Risk€.

On the cost sensitivity the only difference is the position exchange of the 8 ½" section from fourth to third position, replacing the 26" section. This happens because the risk events on the 8 ½" section are more expensive than the 26", moreover the duration influence of the 8 ½" section is affecting this cost. It is visible that risk events do not have an influence on the rank of the duration sensitivity.

The Operation sensitivity stays the same as the standard operational plan because the influences of the risk events are not as representative as the low ROP or running casing speed.

7.2.3 **Well Comparison**

With the present plots is possible to compare the standard operational plan with the risk operational plan in terms of mean cost and duration plots and histograms. As short summary of results the next table helps to understand Figure 36.

Table 8. **Summary table for Standard and Risk operational Plans**

Operational Plan		MEAN	STD Deviation
STANDARD	Duration (days)	181,3	5,15
	Cost (MMUSD)	24,49	0,88
RISK	Duration (days)	185,64	5,39
	Cost (MMUSD)	25,48	1,01

The difference in mean Duration considering risk events is 4.34 days, meaning 2.39% of the standard operational plan, where the maximum duration is 5.84 days more and the minimum duration is 2.02 days more as well. The difference in mean Cost is 0.99 million USD, being

4.04% of the standard operational plan, where the minimum cost is 0.91 million USD more and the maximum cost is 1.94 million USD more.

With Figure 36 is easy to distinguish the difference between the histograms, which show that the risk events add a larger uncertainty to the project, besides the extra cost and time involved. The difference between both standard and risk operational plan is not so marked because the low uncertainty risk events added. When the input data for the standard operation was introduced, the probability distributions added gave enough uncertainty to the simulation, in accordance to the bibliography of Polsky et al (2008).

Some more uncertainty can be added to the simulation, but more information is required to achieve it, even though to adjust the simulation is simple.

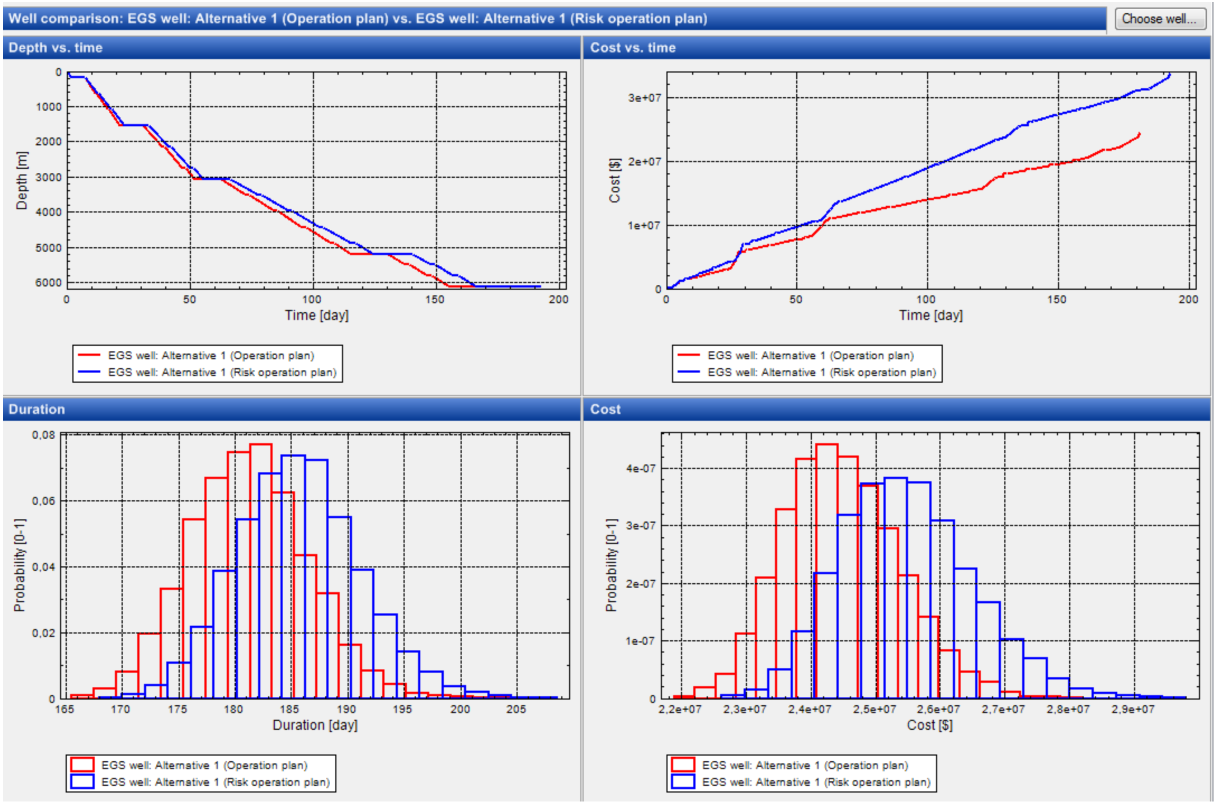

Figure 36.- Well Comparison between the Standard Operational Plan and Risk Operational Plan. Taken from Risk€.

7.3 ROP Analysis

The Rate of Penetration is an important parameter for EGS drilling, as shown in the present work; ROP governs the well construction costs and duration. The geothermal drilling is famous because of its hard rock presence and have the lowest ROP's; several investigations were performed and are still under development for improving ROP on hard and abrasive rocks, that consider drilling automation and bit development (Randeberg et al, 2012).

For these reasons, four more simulations were run for understanding how ROP changes can affect the well construction cost and duration for focusing efforts on improving this parameter.

Table 9. *Comparison of simulation results for different ROP increments*

ROP increment [m/h]	Duration		Cost	
	Mean	**SD**	**Mean**	**SD**
-0,50	213,04	9,66	26.956.915,00	1.215.439,00
base	181,3	5,15	24.495.452,00	880.114,00
0,50	163,02	3,38	23.081.109,00	741.668,00
1,00	150,52	2,48	22.116.661,00	655.537,00
1,50	141,51	1,96	21.436.605,00	609.256,00

The second row of Table 10 shows the unaltered base case of the simulation with no risk events considered, this means that the ROP values are the same as presented in Table 2.

The criterion used for reducing the ROP was to simply decrease the ROP by 0.5 m/h for all values, which includes the minimum, most probable and maximum of the probability distribution for all drilling sections. With these new ROP values the simulation was run, having as result the first row of Table 10 and Figure 37 of the appendix. If the ROP is reduced 0.5 m/h the mean duration increases 31.74 days and the cost also increases 2.46 million USD, which both values represent 17.5% of total duration and 10.05% of total cost.

Following these criterion of reducing/increasing the ROP for all the respective probability distributions new input data was created for re-simulate and compare results with the base case of unaltered ROP.

The third row of table 10 mentions the results of the simulation for ROP values increased 0.5 m/h. This indicates a decrease of the mean duration of 18.28 days and also a decrease in the final cost of 1.41 million USD, representing 10.08% and 5.77% decrement in well duration and cost respectively.

The fourth row indicates an increase in the ROP in 1 m/h. This reflects a decrement in 30.78 days in well construction duration, implying a month of saved time and 16.98% of total duration. Similarly the cost is reduced by 2.38 million USD expressing 9.71% of total cost. Figure 37 is a example of a well comparison between the increment of 1 m/h in ROP and the base case. The rest of the well comparisons with their proper compared well cost and duration histograms are presented in the appendix.

The final row shows the most positive expectation on ROP improvement where this parameter increases by 1.5 m/h with a decreased duration of 39.79 days, which states 21.95% of time decrement. Likewise the total cost decreases 3.06 million USD showing 12.49% of decreased final cost.

The phase and operation sensitivity have the same results as the base case even though the ROP varied in every simulation.

These findings indicate that duration is more affected than cost in this simulation. Therefore if more costs were time dependent, the cost reduction will be more notorious.

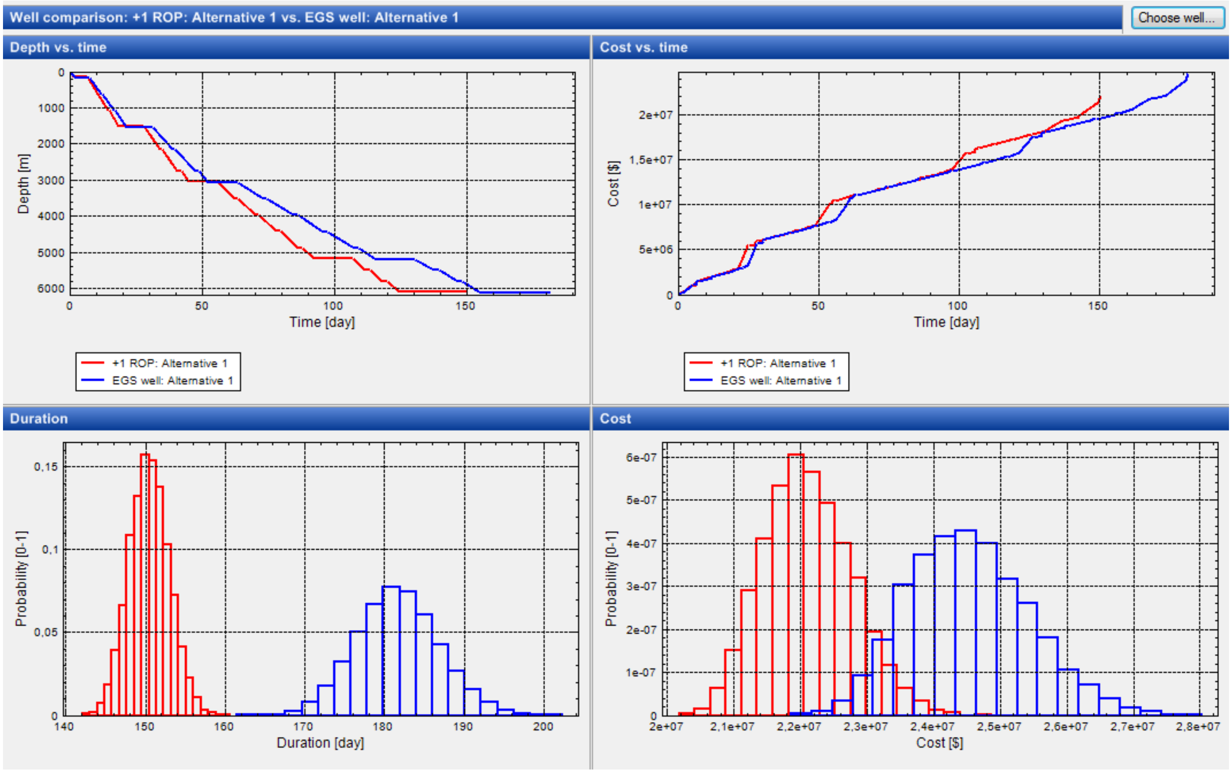

Figure 37.- Well Comparison between the standard input data and an increment of 1 m/h on ROP. Taken from Risk€.

8 Conclusions

This work was aimed at performing probabilistic cost estimation for an Enhanced Geothermal Well and studies the main characteristics of the EGS industry focusing on its drilling technology. Sensitivity analysis was carried out on the results for understanding which parameters have more influence on the final results if the input values are varied. This work had chosen to use the conventional rotary drilling technique instead of the proposed percussion drilling that was mentioned in some alternative geothermal literature.

The input information taken from Polsky et al (2008) was the only source available that had enough detail to perform the simulation. Unfortunately it did not provide the lithology of the location, but according to the document and geothermal experience around the world, the most attractive environment is granite, as the example in Soultz-sous-Forêts (France). This provided data had to be recalculated for introducing it to Risk€, which this procedure is summarized in Table 11 with their corresponding results and finally the input data compatible for the simulator is shown in Tables 2 to 7. It has to be mentioned that the ROP values assumed for the probability distributions in Table 2 are taken from a geological study done in Soultz (Dezayes et al, 2005), where the main environment is granite.

Besides using literature as input data, for introducing the probability distributions were needed expert comments and experiences for completing the data. Understanding how the simulator works helped for adjusting the data into the input panels. Luckily the base input data was detailed enough to be adjusted and introduced into the simulator, giving enough freedom for placing and modifying the data on the different available input panels.

After running the simulation it was possible to study the well cost and duration estimation with uncertainties through several options that helped to understand the intimacy of the budget.

The Drilling operation on every phase was the most important, therefore the most influent operation of all was the 12 ¼” drilling section because it was the longest section with relatively the slowest ROP, according to the Phase Sensitivity analysis.

Considering drilling a deep EGS well is very challenging, as reviewed on the drilling report of GPK-2 (Soultz, France), for this reason risk events such as Lost circulation, Stuck Pipe, Wellbore instability and Difficult Cement jobs were added to the simulation. These risk events are the most representative for EGS drilling, even though some other operations are assumed to happen. All these events were mentioned in Table 8 and chapter 4. With the information of Table 8 another simulation was run, where the results obtained were analyzed the same way as the standard operational plan. These results was predicted to be 4.04% more expensive and lasting 2.39% more than the operational plan without risks. The risks introduced to the simulation added uncertainty to the project, exhibited in the histograms of Figure 36.

The phase sensitivity analysis for the Risk operational plan shows the same first result as in the standard operational plan, which is to drill the 12 ¼" section. This means that the 12 ¼" section is influencing the most for the final well cost, including or not risk events.

It has been proved that ROP is the most important parameter in EGS drilling, for this reason some more simulations were run for studying different ROP input values keeping the other data constant. For having different ROP values it was decided to first decrease the ROP by 0.5 m/h and then to increase it by 0.5 m/h, 1 m/h and finally 1.5 m/h every ROP probability distribution of the input data.

It has been shown on this simulation that improving the ROP by 1 m/h can decrease 9.75% of the total well construction cost. Therefore new technologies referred to bit development or drilling technologies offering higher ROP's have to be stimulated for reducing costs.

ROP was chosen to be varied because in the sensitivity analyses done for the different simulations, the sub operation of drilling the section that had the lowest ROP was always ranked as the most influent for the complete well construction. Even though it was also shown that the extended duration of any operation affected the well cost directly. For this reason avoiding risk events and drilling automation technologies for reducing time and risks has to be considered for decreasing the overall EGS well costs.

By analyzing the obtained percentages it shows that a reduction in the ROP has a higher consequence than increasing the ROP. This means that if the ROP is reduced in a small quantity the cost will increase drastically, but if the ROP is increased by the same value, the cost will reduce not as much as expected. Therefore, considering other strategies for reducing costs on EGS well construction have to be evaluated while developing methods and/or technologies for improving ROP.

It has been proved with this thesis that well construction costs and duration estimation is completely possible for any geothermal well with oil & gas methods. The drilling technology applied to the geothermal industry is very similar to oil & gas, implying that improving EGS drilling is up to the motivation of developing this energy resource and that any achievement of enhancing the drilling process will reduce the total costs not for only EGS wells but also oil & gas wells where hard and abrasive rocks are present.

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Appendices

ROP Analysis

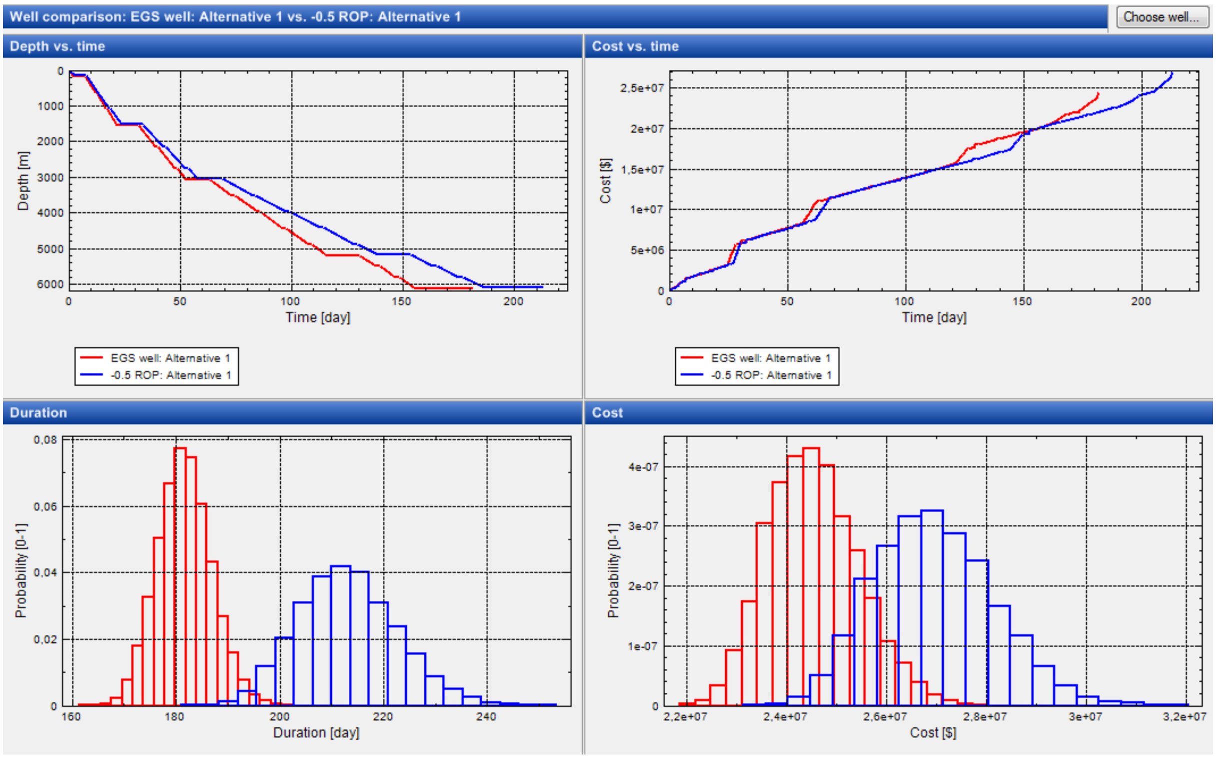

Figure 38.- Well Comparison between the standard input data and an decrement of 0.5 m/h on ROP. Taken from Risk€.

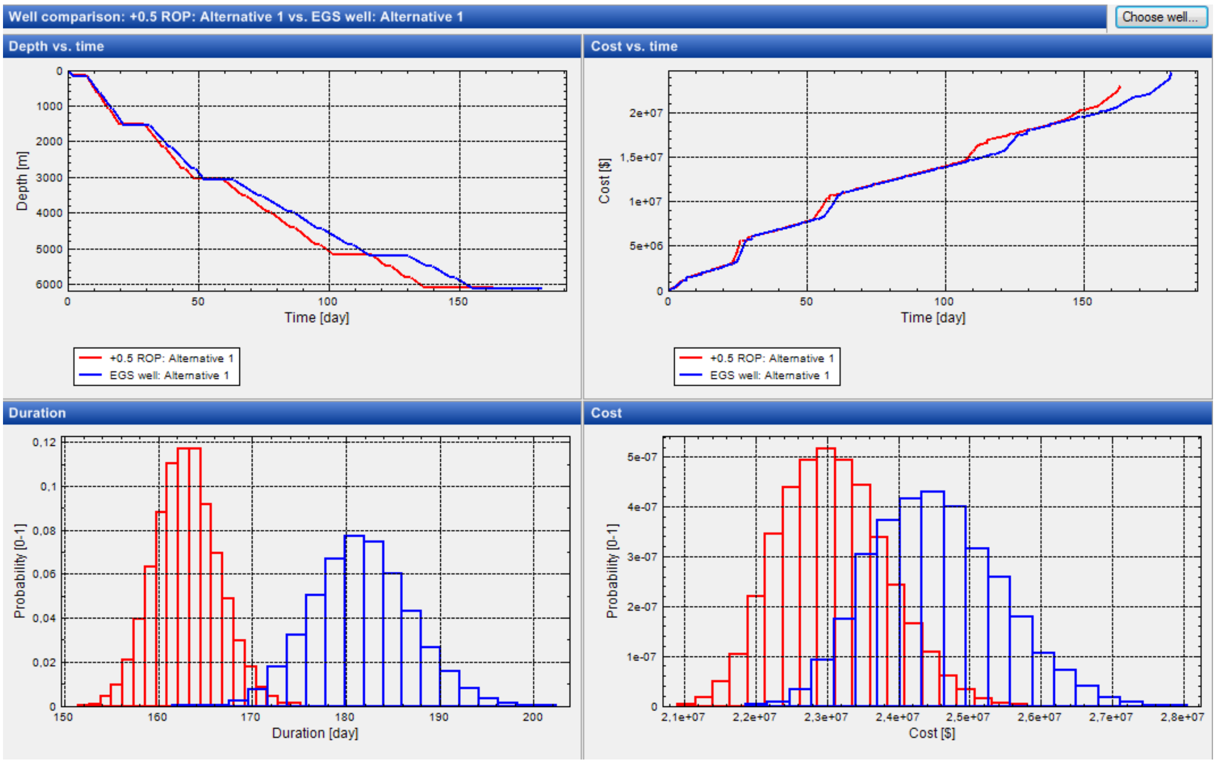

Figure 39.- Well Comparison between the standard input data and an increment of 0.5 m/h on ROP. Taken from Risk€.

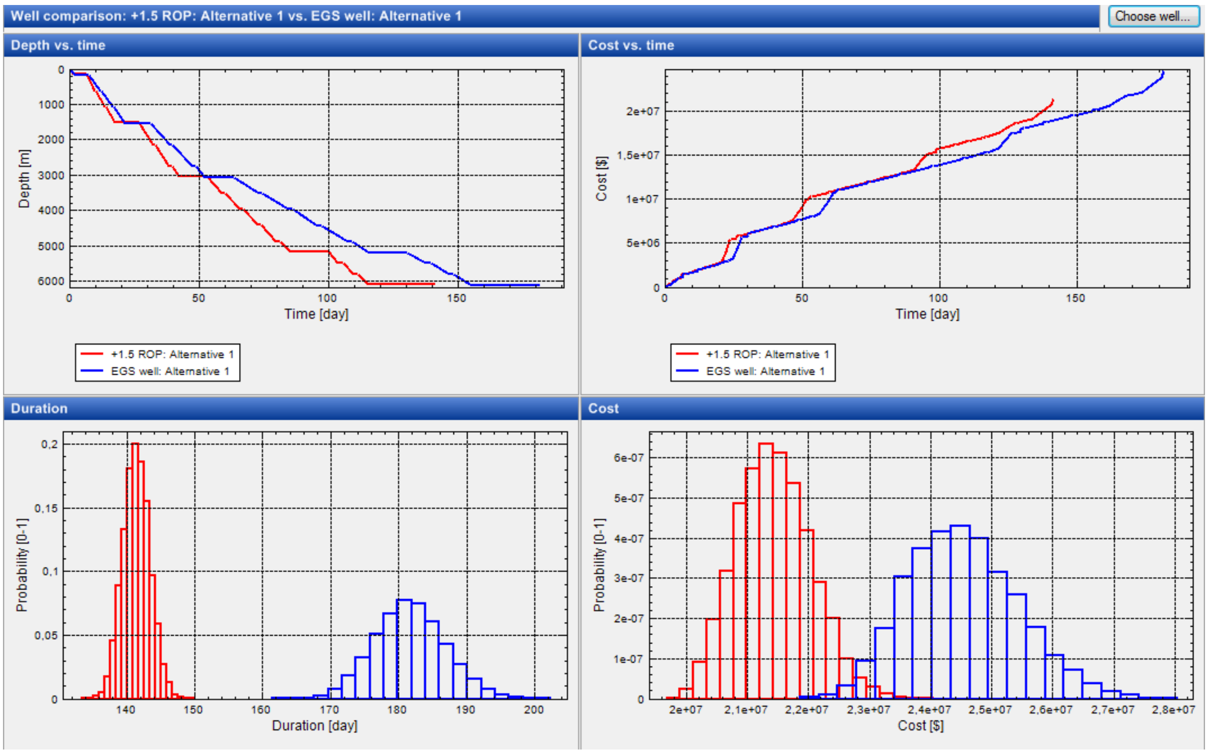

Figure 40.- Well Comparison between the standard input data and an increment of 1.5 m/h on ROP. Taken from Risk€.

Input Data from Enhanced Geothermal Systems (EGS) Well Construction Technology Evaluation Report (Polsky et al, 2008)

DRILLING/CIRCULATION AND BIT PARAMETERS

BIT COST		Unit	Unit price	Quantity	TOTAL
Surface Hole	*36''*	$	80.000	1	80.000
Intermediate Hole	*26''*	$	85.000	4	340.000
Production Hole 1	*17-1/2''*	$	50.000	3	150.000
Production Hole 2	*12-1/4''*	$	25.000	6	150.000
Production Hole 3	*8-1/2''*	$	16.000	4	64.000

DRILLING FLUIDS & SOLID CONTROL

Drilling fluid materials	Unit	Unit price	Quantity	TOTAL
Surface Hole	$/m3	44,03	421	18.515
Intermediate Hole	$/m3	62,90	2.350	147.810
Production Hole 1	$/m3	92,77	1.183	109.740
Production Hole 2	$/m3	133,03	811	107.950
Production Hole 3	$/m3	160,39	167	26.852

Waste Treatment	Unit	Unit price	Quantity	TOTAL
Shakers, Mud Cleaner and Centrifuge Rental	$/day	1.200	143	171.600
Shaker Screens	$	500	50	25.000
Mud Cooler Rental	$/day	750	143	107.250

CASING		Unit	Unit price	Quantity	TOTAL
Conductor Pipe	*40''*	*$/m*	1.312	15	20.000
Surface Casing	*30''*	*$/m*	984	152	150.000
Intermediate Casing	*20''*	*$/m*	623	1.524	950.000
Production Liner 1	*13-5/8''*	*$/m*	709	1.585	1.123.200
Production L-1 Tie Back	*13-3/8''*	*$/m*	771	1.463	1.128.000
Production Liner 2	*9-5/8''*	*$/m*	322	2.194	705.600
Production Liner 3	*7''*	*$/m*	223	975	217.600

CASING SERVICES	Unit	Unit price	Quantity	TOTAL
Casing crews & lay down machine	$	10.000	7	70.000

Table 11 *Continued*

CASING ACCESSORIES	Unit	Unit price	Quantity	TOTAL
Production Liner 1 hanger and running services	$	45.000	1	45.000
Production Liner 2 hanger and running services	$	35.000	1	35.000
Production Liner 3 hanger and running services	$	25.000	1	25.000
Centralizers	$	25.000	1	25.000
Float Shoes and Float Collars	$	57.000	1	57.000

CEMENT VOLUMES	Unit	Unit price	Quantity	TOTAL
Surface Casing	$/m3	3.963	56	220.500
Intermediate Casing	$/m3	3.742	323	1.207.850
Production Liner 1	$/m3	4.780	149	714.400
Production L-1 Tie Back	$/m3	4.151	154	640.200
Production Liner 2	$/m3	5.787	95	552.000
Production Liner 3	$/m3	18.429	18	336.950

LOG COST	Unit	Unit price	Quantity	TOTAL
GEOLOGIC EVALUATION AND RESERVOIR ENGINEERING				
Wireline Services	$	125.000	5	625.000

WELLHEAD COST	Unit	Unit price	Quantity	TOTAL
PRODUCTION EQUIPMENT				
Surface Casing Head	$	20.000	1	20.000
Intermediate Casing Head	$	15.000	1	15.000
Tie-back Casing Head	$	10.000	1	10.000
Master Valves	$	35.000	2	70.000
Wing valves	$	4.000	3	12.000
Nuts, Studs, Flanges and Gages	$	10.000	1	10.000
Wellhead Welding and Installation services	$	12.000	3	36.000

Table 11 *Continued*

DrillString & BHA Costs	10.029		TOTAL	1.434.200
DIRECTIONAL DRILLING SERVICES				
Directional Drilling Equipment	$/day	12.000	92	1.104.000
DRILLING TOOLS RENATAL AND REPAIR				
Stabilizers, Roller reamers and Hole Openers rental	$	900	92	82.800
Rebuild Charges for STB, Roller reamers and Hole Opener	$	50.000	1	50.000
Jars, Intensifiers and Shock subs rental	$/day	800	92	73.600
Rebuild Charges for Jars, Intensifiers and Shock subs rental	$	40.000	1	40.000
Drillpipe, HWDP and drillcollar rental	$/day	150	92	13.800
Drillpipe hard banding and repair	$	100	700	70.000

SPREAD RATE	$/day	29.488	TOTAL	4.216.825
CONTRACT DRILLING RIG	Unit	Unit price	Quantity	TOTAL
top drive rental	$/day	3.200	143	457.600
Rig welding services	$/day	700	143	100.100
Fuel*	gal/day	4	2.500	1.519.375
Rig crew travel & accomodation	$/day	1.000	143	143.000
DRILLING FLUIDS & SOLID CONTROL				
Drilling Fluids Engineer	$/day	900	143	128.700
Sumpless Drilling and Cutting management services	$/day	1.500	143	214.500
DIRECTIONAL DRILLING SERVICES				
Directional Drilling Personnel	$/day	2.000	144	288.000
AIR DRILLING SERVICES				
Air Compressor Standby Day rate	$/day	1.500	75	112.500
Air Compressor Operating rate	$/day	2.500	68	170.000
Air Compressor Personnel	$/day	1.500	68	102.000
Air Drilling Flow Line and separator system rental	$/day	1.000	143	143.000
GEOLOGIC EVALUATION AND RESERVOIR ENGINEERING				
Mud Logging services	$/day	2.000	143	286.000
H2S Monitoring, testing and training services	$/day	750	143	107.250
Geologic services	$/day	400	143	57.200
DRILLING TOOLS RENATAL AND REPAIR				
Tubular Inspection Services	$/day	1.000	143	143.000
WELL CONTROL EQUIPMENT RENTAL AND SERVICES				
BOP Rental	$/day	1.500	143	214.500
Rotating Head Rental	$/day	350	86	30.100

Table 11 Continued

SUPPORT COSTS	**$/day**	**5.850**	**TOTAL**	**836.550**
PLANNING, ENGINEERING AND PROJECT MANAGEMENT				
Rig Site Management	$/day	2.000	143	286.000
Engineering Services	$/day	2.000	143	286.000
RIG SITE LOGISTICS				
Communications	$/day	250	143	35.750
Rig monitoring system	$/day	250	143	35.750
Rig site living accommodations	$/day	500	143	71.500
Potable water and Power	$/day	150	143	21.450
TRUCKING AND TRANSPORTATION				
Equipment transportation	$	500	143	71.500
Vehicle Rental	$/day	50	143	7.150
Forklift and Man Lift rental	$/day	150	143	21.450
FIXED COSTS			**TOTAL**	**175.000**
PLANNING, ENGINEERING AND PROJECT MANAGEMENT				
Project Management	$/month	25.000	6	150.000
Well Insurance	$	25.000	1	25.000
BOP Phase Fixed Costs			**TOTAL**	**67.500**
WELL CONTROL EQUIPMENT RENTAL AND SERVICES				
BOP Inspection and repair	$	10.000	3	30.000
BOP Consumables	$	20.000	1	20.000
Rotating head rubbers	$	1.500	5	7.500
Drillpipe floats	$	500	20	10.000
CONTRACT DRILLING RIG				
Rig Rate	**$/day**	**28.000**	**143**	**4.004.000**
TOTAL				**21.254.091**

Table 10.- *Input Data from Polsky et al (2008)*