TECHNICAL AND ECONOMIC ASSESSMENT OF ADOPTING UNDER-BALANCED DRILLING AT THE OLKARIA GEOTHERMAL FIELD

FELIX KIIO NZIOKA

MASTER OF SCIENCE

(Energy Technology)

JOMO KENYATTA UNIVERSITY OF

AGRICULTURE AND TECHNOLOGY

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Technical and economic assessment of adopting under-balanced drilling at the Olkaria geothermal field

Felix Kiio Nzioka

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DECLARATION

This thesis is my original work and has not been presented for a degree in any other University.

Signature …….. Date ……

Felix Kiio Nzioka

This thesis has been submitted for examination with our approval as University supervisors.

Signature ……..... Date……

DR. John Githiri

JKUAT, KENYA

Signature ……. Date ……

DR. Joseph Kamau

JKUAT, KENYA

DEDICATION

I dedicate this thesis to my son Ryan Nzioka.

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LIST OF ABBREVIATIONS

CHDP	Chip Hold Down Pressure
HAZOP	Hazard Operability
HUBS	Hydraulic Under Balanced Simulator
IADC	International Association of Drilling Contractors
MD	Measured Depth
NPV	Net Present Value
PSI	Pounds per Square Inch
ROP	Rate Of Penetration
RPM	Revolutions Per Minute
SPE	Society of Petroleum Engineers
UBD	Under-Balanced Drilling
WOB	Weight On Bit

ABSTRACT

The current drilling practice at the Olkaria geothermal field is a mixture of overbalance, near balance and balanced drilling. The planned time to drill a well at Olkaria is sometimes exceeded by a big margin when down hole challenges are encountered while drilling. The common down hole problems encountered in the field are loss of circulation, minimal Rate Of Penetration (ROP) and possible formation damage which consequently leads to reduced productivity of a well. It is evident that, the longer the drilling time, the higher the cost of the well. Under-Balanced drilling is the application of drilling fluids to the bore at a pressure slightly less than the formation fluids pressure. If the process is well executed, it may lead to the reduction or even elimination of most down hole challenges. This research was aimed at establishing the effectiveness of Under-Balanced drilling (UBD) in solving the down hole problems experienced at the Olkaria geothermal field. In order to carry out this exercise, simulation of Under-Balanced drilling conditions using the Hydraulic Underbalanced Simulator (HUBS) was done utilizing data from the field. Secondly, the economics of adopting Under-Balanced drilling technology at the field was also done and finally the potential hazards associated with Under-Balanced drilling were assessed. Data from four geothermal wells namely OW 731A, OW 915B, OW 731 and OW 804 was used in the simulation exercise. Simulated annulus volume fraction profiles showed cuttings concentration of less than 5% and an optimum circulation flow rate of 0.03 m^3/min. The costs associated with loss of circulation and increased hole cleaning on average represented 3.7% of the total average well cost. The projected benefit cost ratio obtained for the UBD case was 1.40 while the one for the conventional case was 1.25. The Net Present Value for the Under-Balanced drilling case was higher than that of the conventional case. In the initial HAZOP analysis for the UBD procedure, the installation of the rotating control device scored high in operability aspect while choke valve regulation scored high in safety aspect.

CHAPTER ONE

INTRODUCTION

1.1 Background

The Olkaria geothermal field is in the Kenyan Rift valley which is part of the great East African Rift valley. Exploration for geothermal resources in Kenya started in 1950's with mainly geological investigations in the region between Olkaria and Lake Bogoria in the north rift. The exploration resulted in the drilling of two wells X-1 and X-2 which encountered high temperatures (Mariita, 2009). After extensive geo-scientific surveys in the early seventies, exploration drilling started in 1974 and continued through 1977. Following evaluation of the initial drilling results, a feasibility report was produced in 1977. The following year 1978, production drilling commenced and continued until 1983. Sufficient resource capacity was confirmed for installation of the first power plant of 45 MW at Olkaria between 1981 and 1985 (Ouma, 2009). Olkaria geothermal field is divided into seven sectors (Mwarania, 2011). The sectors are Olkaria East, Olkaria North East, Olkaria South West, Olkaria Central, Olkaria North West, Olkaria South East and Olkaria Domes. The fields are named with respect to Olkaria Hill.

The current drilling practice in the Olkaria geothermal field is a mixture of overbalanced drilling, near balance and balanced drilling. In the context of this study, this drilling practice will be referred as conventional drilling. The drilling fluids currently used in the current drilling practice are varied depending on the section of the hole. For the surface hole and intermediate hole sections, mud is used and for the production hole section aerated fluids and foam are employed. While drilling conventionally in an overbalanced state, the hydrostatic pressure of the drilling fluid exerts a force against the rock that is being penetrated, thus requiring more energy to remove the rock (Saad & Jerome, 2003). Figure 1.1 shows the location of geothermal prospects within the Kenyan rift valley.

Common rock types in geothermal reservoirs include granite, granodiorite, quartzite, greywacke, basalt, rhyolite and volcanic tuff (Finger & Doug, 2010).

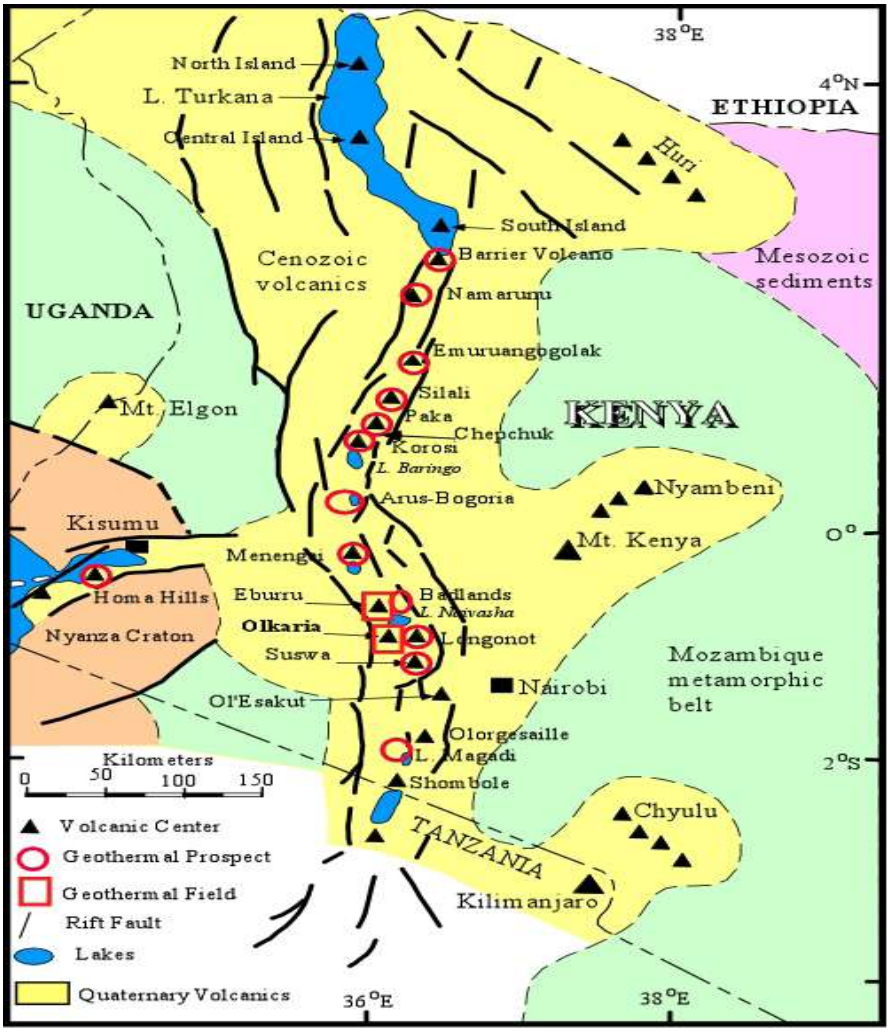

Figure 1.1: Geothermal manifestation areas in the East African Rift (Mariita, 2009)

Compared to the sedimentary formations of most oil and gas reservoirs, geothermal formations are, by definition, hot (production temperature range from 160°C to above 300°C) and are often hard (240+ MPa compressive strength), abrasive (quartz content above 50%), highly fractured (fracture apertures of centimeters), and under-pressured (

Finger & Doug, 2010). Under-Balanced drilling conditions can be varied by either increasing or reducing the back pressure at the wellhead or by changing the air flow rate from the compressors and the pumping rate of the water (Sichei, 2011). Under-Balanced drilling is preferred over conventional drilling in some cases to save cost of drilling and increase production rate by increasing rate of penetration, avoiding or minimizing formation damage, reducing lost circulation and getting earlier production. Along with its many advantages, there however are few limitations in Under-Balanced drilling (UBD). Since the bottom hole pressure is always kept below the formation pore pressure in Under-Balanced drilling (UBD), there is an increased risk of wellbore instability, which must be addressed at both planning and drilling phases (Sardar, 2006). Bjelm (2006) points outs that use of UBD introduces operational complexity, multiphase flow regimes demands certain skills, improper hole cleaning if safe flow regimes are not established, distorted and mixed cuttings making geological interpretation hard and increase in daily cost due to the extra equipment and crews required.

1.2 Geology of the Olkaria geothermal field

The geothermal resource is associated with an area of quaternary volcanism in which rhyolites dominate. The youngest volcanic rocks are ashes, pumiceous obsidian rhyolites, vent breccias and agglomerates. Ashes found in the crater zone of Olkaria hill, at the Olbotut lava and to the north of the field overline series of beds of tuffs and sediments found in the Ol Njorowa gorge and in the bore field (Odongo, 1984). Along the Ol Njorowa gorge, massive, columnar-jointed comendite line up most of the walls. The massive rocks are often capped by obsidian skin of probably the same composition as the comendites. The Ol Njorowa gorge formation made up of tuffs and sediments shows a thickness of well over 100 meters in the gorge and up to 155 meters in the bore field. The unit appears to thicken towards Mt. Longonot, with much of the trachytes covered by the series of beds of pyroclastics and sediments (Odongo, 1984).The stratigraphy of all the sectors is as shown in Figure 1.2.

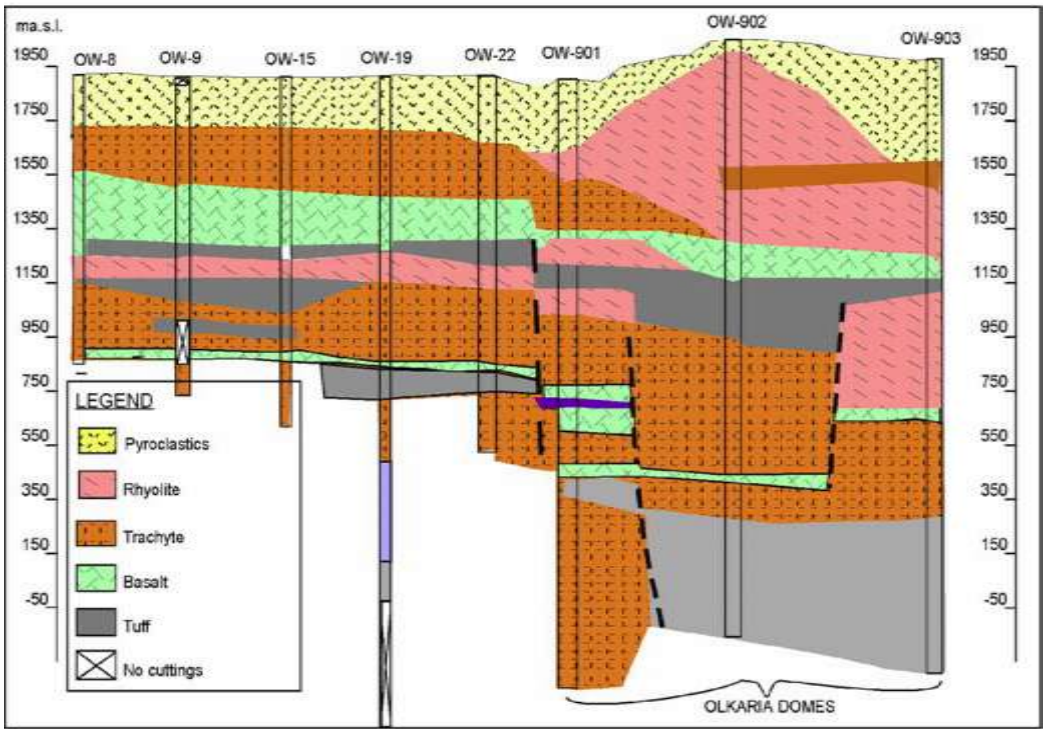

Figure 1.2: Stratigraphy of the Olkaria Geothermal Steamfield (Mungania, 1999)

1.3 Scope of the study

This study covers wells in the Olkaria geothermal field, the wells drilled in the various sections of the field and their geology. The hole cleaning challenges encountered in these sections were assessed with regard to their contribution to increased well costs. Simulation of Under-Balanced drilling using data obtained from the various sections of the field with the view of determining whether Under-Balanced drilling is a solution to the down hole problems was carried out. An economic evaluation of Under-Balanced drilling at the field with regard to hole cleaning and the influence of Under-Balanced drilling to the overall development cost was also done. Lastly the study also looked into the potential operational risks associated with Under-Balanced drilling for geothermal.

1.4 Problem statement

Geothermal well drilling is usually faced by a number of down hole challenges. These challenges include loss of circulation of the drilling fluids, low rate of penetration, formation damage and reduced productivity from a well. Loss of circulation can either be partial or total. Lack of effective hole cleanliness due to loss of circulation may lead to a stuck drill string. Effective hole cleaning is a situation whereby all drill cuttings are transported to the surface. The planned time to drill a geothermal well can either be optimistic (55 days) or pessimistic (60 days) for a vertical well while that of a directional well is 65 days optimistic and 70 days pessimistic. The time to carry out re-circulation of fluids to ascertain hole cleanliness whilst drilling has a cost factor emanating from an increase in the overall drilling time and thus impacting negatively on the cost of the well. Formation damage pertains the partial blockage of formation fractures which normally convey the steam to the well bore. Under-Balanced drilling leads to inflow of formation fluids into the well bore thus eliminating the possibility of drilling fluids leaking into the formation and ensuring good transport of cuttings to surface. These challenges can be kept to a minimum or even eliminated if advanced drilling technologies are fully adopted. Consequently, all these challenges leads to increased drilling time, increased cost of drilling materials, increased labour cost and reduced productivity of a well. Eventually the cost of drilling a well will increase. This study investigates how the overall cost of a well can be reduced if advanced drilling technologies are fully utilized.

1.5 General objective

To assess the effectiveness of Under-Balanced drilling if fully adopted over conventional drilling at the Olkaria geothermal field.

1.6 Specific objectives

1. To simulate Under-Balanced drilling conditions using data from the Olkaria field.

2. To evaluate the economic benefits of adopting Under-Balanced drilling over conventional drilling at the field.

3. To assess the operational risks of adopting Under-Balanced drilling at the Olkaria geothermal field.

1.7 Justification

Overbalanced, near balance and balanced drilling may lead to the blockage of fractures in well permeable zones. This is a state of lost circulation and drilling fluids will be lost in the formation. These fluids should be re-circulated so as to optimize on their use. Balanced drilling also may lead to ineffective hole cleaning where by regrinding of cuttings may occur in vertical wells and a cuttings bed in directional wells. This may lead to an increase in the circulation time in an effort to ascertain hole cleanliness. Tellez (2003) points out that pipe connection and tripping in and out of the hole may lead to fluid separation thus causing bottom hole pressure fluctuations which may be out of the desired drilling pressure window. These problems have direct impact on the ultimate cost of the well. Drilling technology has had advancements and new technologies like Under-Balanced drilling which has both technical and economic benefits through the reduction and elimination of down hole problems can eventually lead to reduced well costs.

CHAPTER TWO

LITERATURE REVIEW

2.1 Theory of Under-Balanced drilling

Under-Balanced drilling is defined as drilling with the hydrostatic head of the drilling fluid intentionally designed to be lower than the pressure of the formations being drilled (Smith, Gregory, Munro & Muqeem, 2000). The hydrostatic head of the fluid may naturally be less than the formation pressure or it can be induced. The induced state may be created by adding natural gas, nitrogen or air to the liquid phase of the drilling fluid. Whether the underbalanced status is induced or natural, the result may be an influx of formation fluids which must be circulated from the well and controlled at surface. Under-Balanced drilling in practical terms will result in flow from one or more zones into the wellbore (this is more likely, however, to be solely from one zone as cross-flow is likely to result) or where the potential for flow exists. Drill bits break the rock by a combination of several processes including: compression (weight-on-bit), shearing (RPM) and sometimes jetting action of the drilling fluid.

According to Rabia (2001) the rate of penetration is affected by numerous parameters namely: Weight On Bit (WOB), Revolutions Per Minute (RPM), bit type, bit wear, hydraulic efficiency, degree of overbalance, drilling fluid properties, hydrostatic pressure and hole size. The difference between the mud hydrostatic pressure and pore pressure is called the Overbalance or "Chip Hold Down Pressure (CHDP)". This overbalance prevents formation fluids from entering the wellbore while drilling. However, this overbalance (CHDP) also acts to keep the rock cuttings held to the bottom of the wellbore. The effects of bit rotation and hydraulics offset this force and ensure that cuttings are lifted from the bottom of the hole. The CHDP (differential force) has one of the largest effect on ROP especially in soft to medium strength formations. If all parameters affecting ROP are held constant whilst drilling uniform shale sequence then

ROP should decrease with depth. Experimental work by Rabia (2001) has shown that the effect of increasing pore pressure on ROP is limited to a differential pressure of 500 PSI. However, when the overbalance is greater than 500 PSI, ROP shows little change over large changes in differential pressure.

The first oil wells drilled in the l800s were drilled Under-Balanced (Saad & Jerome, 2003). These wells were drilled with insufficient fluid pressure in the annulus. Consequently, when a permeable formation was encountered, the wells flowed. The flow was uncontrolled flow, thus it resulted in lost reserves. The earliest Under-Balanced drilling (UBD) patent can be traced back to the mid-1800s when a patent was issued for using compressed air to clean out cuttings from the bottom of a hole (Pathak, 2010). Advances in the industry continued through the mid-1900s. People began to understand the use of mist and multiphase fluids to control down-hole fires and provide a higher tolerance to water influxes. Advances were made in understanding and modeling of air and multiphase systems. The growth of this technology continued into the early 1900s with the first application of multiphase fluids occurring in the 1930s.The use of multiphase fluids (either air or natural gas with water or oil) became popular in oil well drilling throughout the southern United States in the 1930s (Saad & Jerome, 2003). Mist drilling was first introduced in late 1930s. Drilling with pure air or natural gas also increased at this time.

Closed systems were introduced to capture produced fluids and improve safety. Foam came into favor in the 1960s because of its superior hole-cleaning ability as compared with air and multiphase systems. During the 1970s, Under-Balanced drilling (UBD) technology was used in limited applications. Problems with Under-Balanced drilling (UBD) techniques limited the growth of the industry. Environmental problems were the largest obstacle, particularly in gas drilling systems, where large amounts of dust were released into the atmosphere. In single-circulation foam systems, the waste generated was a serious concern. Due to insufficient technological advancements there were frequent instances of accidents due to lack of effective wellbore control techniques

(Saxena, Ojha & Pathak, 2014). Saxena *et. al*., 2014 points out that overbalanced drilling was used as a mechanism for primary well control. Most wells drilled underbalanced prior to 1985 were low-pressure applications. The aim of many of these applications was to increase the rate of penetration (ROP) in non-productive horizons. New technologies developed in the late 1980s and through the 1990s have seen a re-emergence of UBD, with improvements in multiphase modeling capabilities and the development of higher pressure rotating control heads, active rotating control heads, four-phase separators, recycling foam systems, electromagnetic MWD systems and membrane nitrogen generation systems (Saad & Jerome, 2003).

Under-Balanced drilling techniques are commonly divided into three categories which include Performance drilling which is the application of air, mist or foam drilling fluid systems to drill sub hydro-statically. It aims to reduce drilling costs by increasing the rate of penetration. Managed pressure drilling is the second category and it involves drilling with a closed, pressurizable fluid system to more precisely control the wellbore pressure profile. It intends to ascertain the down-hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly (Ogena, Gonzales, Palao, Toralde & Bayking, 2007). The dynamics of conventional and Under-Balanced drilling are as shown in Figure 2.1 and 2.2. The third category is underbalanced reservoir drilling which involves drilling with the borehole pressure designed and maintained below reservoir pressure to intentionally invite fluid influx. It is intended to increase reservoir productivity by reducing formation damage and enhancing reservoir characterization. A schematic diagram of Under-Balanced drilling is shown in Figure 2.3. Equations 2.1 and 2.2 describe overbalanced and balanced drilling while equation 2.3 describes Under-Balanced drilling.

$$H_s > H_f \quad 2.1$$

$$H_s = H_f \quad 2.2$$

$$H_s < H_f \quad 2.3$$

Where; H_s and H_f are hydrostatic pressure inside drill string and formation pressure respectively.

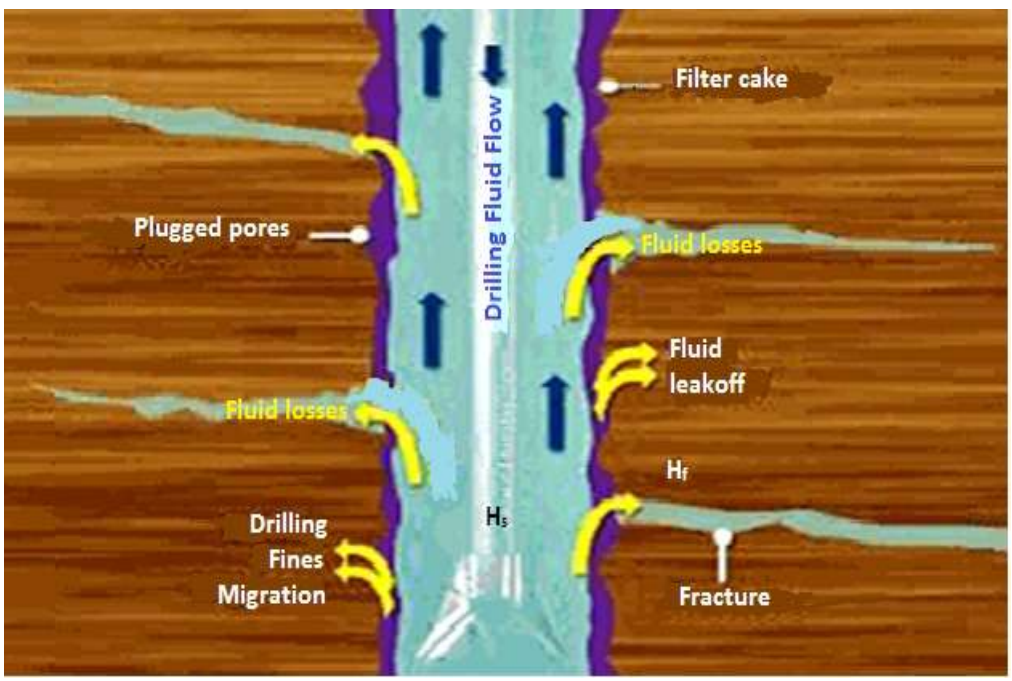

Figure 2.1: Conventional drilling (Putra, 2008)

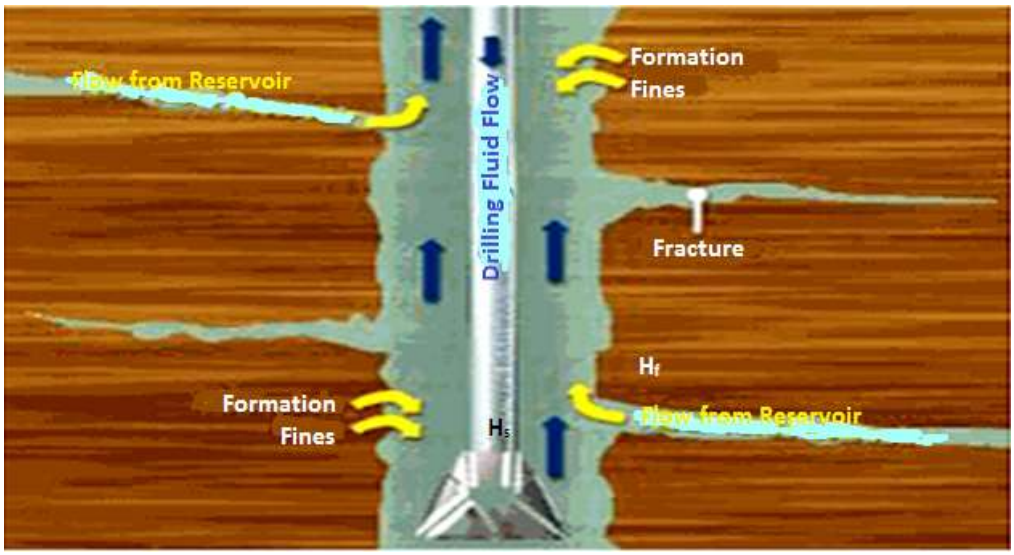

Figure 2.2: Under-Balanced drilling (Putra, 2008)

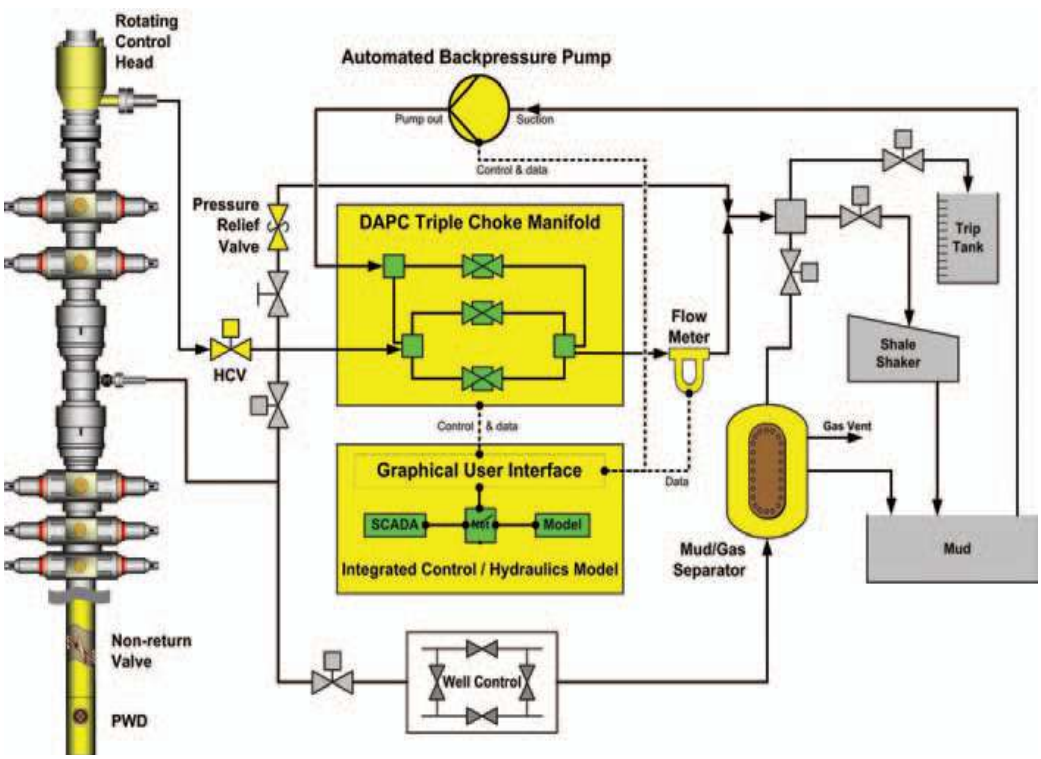

Figure 2.3: Illustration of Under-Balanced drilling (UBD) system

2.1.1 Fluids for Under-Balanced drilling (UBD) operations

To drill underbalanced; a decision must be made on which fluids will be used for that particular location in order to maintain control. Choices include gas, mist, foam or liquid. The decision of which fluid options to choose is dictated by the conditions of the drillingsystem.

For UBD operations one must consider issues such as reservoir characteristics, geophysical compatibility, well fluid disposition, temperature and environmental compatibility. High-pressure zones require lightened fluids generally consisting of aerated drilling mud or foam. The fluids are mixed with gas to achieve the desired density and a pump is used to inject the mixture in the gas stream before it enters the well. Because gas and liquid compressibility values differ significantly as pressure and temperature change, the liquid fraction changes as well. Stable foam is another preferred drilling medium because of its ability to carry high volumes of cuttings. New recyclable foam reduces environmental concerns and disposal costs, while remedying containment problems associated with previous foams. Foam also provides superior hole cleaning with low bottom hole pressure to maximize the rate of penetration. Foamed fluid boosts the efficiency of drilling through surveying and allows evaluation of formation fluids while those fluids are co-mingled with the drilling fluid (Wilkes, 1999).

2.2 Simulation of Under-Balanced drilling operations

The Hydraulic Under-Balanced Simulator (HUBS) is a simulation tool designed to perform calculations for Under-Balanced drilling operations. Hydraulic design is the key to the success of an underbalanced operation because it determines whether or not the operation is underbalanced and how much underbalanced margin exists between the fluid pressure in the wellbore and the formation pressure, secondly hydraulic design is the key to achieve an effective hole cleaning which has a significant effect on the efficiency of Under-Balanced drilling operations and lastly hydraulic design is the basis

for selection of pump, compressor, fluid handling equipment and other facilities (Signa Engineering Corporation (SEC), 2012). The annulus volume fraction for cuttings in an overbalanced drilling operation may be more than 5 % when compared to that of an Under-Balanced drilling operation. Determination of optimum circulation flow rate in a conventional drilling operation may not be entirely pegged on hole cleanliness but on prevailing conditions in the wellbore. Tian & Finger (2000) points out that the available algorithms before year 2000 treated heat transfer between fluid in the wellbore and the formation as a transient problem while assuming that hydraulic parameters can be treated as steady state while the current algorithms treat hydraulic parameters as transient. According to Tellez (2003) the Under-Balanced drilling simulation models developed before year 2003 use the Beggs and Brill empirical correlations and the simplistic mechanistic model while the current ones use state of the art mechanistic steady state models.

The numerical model developed by Osunde & Kuru (2008) obtained a depth-cuttings fraction plot with a decreasing trend as the fluids travelled up the wellbore but their model did not plot the annulus volume fractions for liquid and gas phases. A two fluid model developed by Khezrian, Hajidavallo & Shekari (2015) established that, the liquid flow rate should be less than 0.32 m^3/min to keep the drilling operation in the UBD condition considering a gas flow rate of 15 m^3/min.

2.3 Economic evaluation

The economic evaluation of alternative projects or designs can be categorized into two categories which are; those alternative projects with equal benefits but different costs and those alternative projects with different benefits as well as different costs. The benefit/cost ratio can be calculated on an annual basis if the levelized uniform annual benefits and costs can be calculated easily; otherwise, it can be calculated on a discounted basis. The benefit/cost ratio is very sensitive to the interest rate or discount rate used to calculate the annual capital costs of a project. If this interest rate changes,

the benefit/cost ratio will also change. The net benefits of a project are equal to the total benefits less the total costs of that project. Like the benefit/cost ratio, the net benefits can be calculated either on a discounted basis or an annual basis of the uniform annual benefits and costs can be computed. The net annual benefits are also sensitive to the interest rate used for cost calculations or for discounting future values. In general, a higher interest or discount rate will reduce the benefits of a project, and a lower interest rate will increase the net benefits. The internal rate of return on a capital investment is the discount rate at which the total discounted costs associated with an investment equal to the total discounted benefits of that investment. It is also defined as the compound interest that makes the Net Present Value equals zero.

In order to gain profit from the producing well, the operating expenses and the capital costs have to be justified by the production and sales. The costs are categorized into two separate categories, the total intangible and the total tangible costs (Ngosi, 2010). The intangible costs include the fees for preparing the site such as obtaining the legal rights and documents, the surface damages done while clearing the site, building roads and fences, drilling contractor services, general services like welding, dirt work and installation process. Specialized services such as open-hole evaluation, cementing, stimulation, fishing services and other services would contribute to the amount of intangible costs. Other miscellaneous cost would cover the drilling overhead, the general labor, insurance, company benefits and also taxes. The tangible costs would comprise of the casings, tubing, bits, subsurface equipment and also surface equipments. According to Le´colier, Herzhaft, Ne´au, Quillien and Kieffer (2005) the cost of drilling fluids amounts to 25% - 40% of total drilling costs.

Pa'lsson *et. al*. (2014) in their paper described loss of circulation in the drilling of well IDDP 1 in Iceland as follows; minor mud losses occurred in the first 1000 meters with losses being cured by lost circulation material, losses of 20 liters/second were experienced at 1432 meters. They went ahead to state that losses in excess of 60 liters/second were experienced at 2043 meters and the losses could not be cured. The

drilling fluid system had to be changed from weighted fluid to water and the drilling continued without losses until 2054 meters where total loss of circulation was experienced after a side track emanating from an unsuccessful fishing operation. A cement plug was placed in the well and drilling continued from 2060 meters with total loss of circulation occurring at 2076 meters. Continued problems with stuck pipe and unsuccessful fishing attempts at 2103 meters forced a second side track. Mud losses continued after the side track with total loss of circulation occurring at 2071. Drilling was terminated upon reaching magma at 2100 meters. Another case history described by Bolton, Hunt, King, and Thompson, (2009) points out that major loss of circulation was experienced at 350 – 373 meters in the drilling of well WK 204 in New Zealand. In their work they did not quantify how the loss of circulation materials imparted to the overall well cost.

2.4 Under-Balanced drilling scenarios around the globe

Under-Balanced drilling operations have been carried out in Lund Sweden whereby the hydrostatic pressure in the well bore was reduced by means of hooking up three air compressors and a booster releasing the compressed air through the drill pipes and back via the annulus. The three compressors, and a booster, had a capacity of delivering around 100 m^3/min of air, and the maximum pressure delivery was around 140 bar (Bjelm, 2006). However he points out that at one occasion during air drilling the hole was not properly cleaned.

In West Texas, UBD was used to increase the rate of penetration (ROP). For the first leg of the project, the operator drilled a 12-1/4 inch hole to 1,100 ft and set 9-5/8 inch casing. This top section was drilled with a conventional fluid system. For the bottom section, the operator drilled a 7-7/8 inch hole to 8,000 ft, using foam that was inhibited for shale hydration and corrosion (Wilkes, 1999). Under-Balanced drilling has been applied in the Tongonan geothermal field in the Philippines where two wells were drilled with the same target in the same sector where there is significant pressure

drawdown. The first well drilled with conventional mud while the second one was drilled with aerated mud/water at Under-Balanced drilling conditions. The target depth of the two wells was 2900 meters. Unrecoverable losses and blind drilling led to the call of an early finish while drilling with conventional mud fluids. These losses led to the increase in total dissolved solids in steam from adjacent wells. The major impact of these problems was the reduction in total output of the field and forced acidizing of production wells that had communicated and had been damaged by mud while drilling. Learning from this experience, subsequent drilling in the same sector was conducted with aerated drilling, and full circulation returns were recovered by adjusting the air-water and air mud ratios. Good hole cleaning due to the maintenance of full circulation led to the completion of these wells at much deeper levels than when they were drilled with conventional mud systems. One well was completed to 2,900 meters with air drilling applied at the production casing interval only, and mud as the drilling fluids from the 9-5/ 8 inch shoe to the bottom hole (Sarmiento, 2008).

Under-Balanced drilling has also been employed in the Kirchweidach geothermal project in Bavaria, Germany, where by the area is faced with severe mud losses and differential sticking in the reservoir formation. The project's objective was to erect a power plant that would produce 6 to 8 MW of electricity and supply the local town and industries with district heating using thermal energy. The GT 1 open-hole section was drilled in two phases using four Under-Balanced drilling (UBD) runs. Initially, UBD Runs 1 and 2 were drilled from the 10-¾ inch liner shoe at 3,664 meters to 4,503 meters Measured Depth (MD). A subsequent acid job and well test proved unsatisfactory, so the UBD separation and nitrogen injection packages were rigged up again. UBD Runs 3 and 4 were drilled from 4,505 meters Measured Depth (MD) to 4,937 meters MD. In the first UBD run, with ROP consistently low at 1 meter/hr, the decision was made to pull out of hole and change the bit. This decision may have been reached because of the low rate of penetration. At this point, the bit had spent 96 hours on bottom. An average instantaneous ROP of 11.6 meters/hour across for this run was recorded, which was decreased by the time spent drilling with the greatly deteriorated bit. In the second UBD

run, an average instantaneous ROP of 8.5 meters/hour was recorded for this run and in the third UBD run, the average instantaneous ROP for UBD Run 3 was 15.3 meters/hour. Lastly, the average ROP for the fourth UBD section was 9.6 meters/hour (Essam, Stephen, Gareth, Julio & Darko, 2012). The total section length of the well which was drilled underbalanced is 1271 meters and the average rate of penetration for the four UBD runs is 11.25 meters/hour. However this well was drilled with methods which varied from at-balance to Under-Balanced conditions therefore the benefits attained could not be entirely attributed to Under-Balanced drilling.

This work therefore concentrated in showing effective hole cleaning and maintenance of Under-Balanced drilling conditions in the wellbore. Lost circulation and hole cleaning cost elements, economic evaluation and operational risks analysis for UBD were also identified as areas of concern.

CHAPTER THREE

METHODOLOGY

3.1 Introduction

Simulation of Under-Balanced drilling operations was undertaken for four geothermal wells namely OW 731A, OW 915B, OW 804 and OW 731. The parameters considered are rate of penetration, formation pressures, drilling cost savings for the various hole sections and the potential for production increase. The material consumption for wells drilled conventionally at the Olkaria field such as Bentonite and water, were computed in order to establish the cost saving in terms of drilling materials utilization. In order to determine the effectiveness of Under-Balanced drilling in solving down hole problems, simulation of Under-Balanced drilling operations was carried out using the Hydraulic Under-Balanced Simulator. The parameters used in the simulation exercise include drill string sizes, the drilling fluids, formation type and formation pressures.

The Hydraulic Under Balanced Simulator (HUBS) offers calculations on pressure, velocity and cutting accumulation prediction, circulation flow rate (s) optimization, pressure matching along the flow path, Under-Balanced drilling with down hole motor and mud cap drilling calculations (SEC, 2012). The International Association of Drilling Contractors (IADC) well classification formed an essential first step in the risk assessment. The next step in the assessment was the identification of potential hazards for Under-Balanced drilling in geothermal. Potential consequences to people, assets and the environment in relation to the probability of occurrence were also investigated by the use of an assessment matrix and a Hazard Operability (HAZOP) analysis sheet categorizing the risks into low, medium and high.

3.2 Equations used in developing HUBS

The HUBS model is designed to handle multi phase flow of gas, liquid, and solids in the well, and heat transfer between the fluids in the well and the formation. Energy equations are created for fluids inside the drill string, in the wellbore annulus, as well as for heat transfer in the formation (SEC, 2012).

In the development of the Hydraulic Under-Balanced drilling Simulator (HUBS), continuity equations and momentum equations may have been used. Major variables calculated by the model were pressure, temperature, liquid holdup, solid concentration and velocity. Numerical algorithms were developed to solve the well bore and formation equations. The implicit finite difference scheme was used to discretize the set of partial differential equations while the backward difference scheme was used for the first order derivatives in the numerical scheme for hydraulics. The set of nonlinear equations in the direction of flow were solved using an iteration technique. Energy equations were discretized using the implicit finite difference scheme, first order derivatives used the backward difference scheme and second order derivatives used the non-uniform grid scheme in the heat transfer numerical scheme. The standard Gauss elimination with banded matrix solved the set of linear equations while temperature distributions were solved simultaneously (Tian & Finger, 2000). Data on the configuration of the simulation domain was not available.

Continuity equations

Continuity equations were derived from mass generation which could be as a result of either mass transfer between phases or inflow from and outflow to the formation (Tian & Finger, 2000).

$$\frac{\partial}{\partial_t}(\propto_g \ \rho_g) + \frac{\partial}{\partial_t}(v_g \ \propto_g \ \rho_g) = M_g \qquad 3.1$$

$$\frac{\partial}{\partial_t}(\propto_L \rho_L) + \frac{\partial}{\partial_x}(v_L \propto_L \rho_L) = M_L \quad 3.2$$

$$\frac{\partial}{\partial_t}(\propto_s \rho_s) + \frac{\partial}{\partial_x}(v_s \propto_s \rho_s) = 0 \quad 3.3$$

Where; v_g, v_L & v_s are velocity of gas phase, liquid phase and solids phase respectively. $\propto_g$, $\propto_L$ & $\propto_s$ are volume fractions of gas, liquid and solids respectively. ρ_g, ρ_l & ρ_s are density of gas, liquid and solids phases. M_g & M_L represent mass generation of the gas and liquid phases respectively.

Momentum equations

The momentum equations are for mixtures of gas and liquid but not for separate momentum equations for the gas phase and liquid phase. This is based on the availability of related force correlations (Tian & Finger, 2000).

$$\frac{\partial}{\partial_t}(\propto_s \rho_s v_s) + \frac{\partial}{\partial_x}(v_s^2 \propto_s \rho_s) = F_D - \propto_s (\rho_g - \rho_{gL}) g cos\theta \quad 3.4$$

$$\frac{\partial}{\partial_t}(\propto_{gL} \rho_{gL} v_{gL}) + \frac{\partial}{\partial_x}(v_{gL}^2 \propto_{gL} \rho_{gL}) = -\frac{\partial p}{\partial x} - \frac{f_{gL} v_{gL}^2 \rho_{gL}}{2d} - F_D - \rho_{gL} g cos\theta \quad 3.5$$

Where;

$$F_D = \frac{0.75 C_D \rho_{gL}(v_{gL} - v_s)|v_{gL} - v_s| \propto_s \propto_{gL}^{-2.67}}{d_s} \quad 3.6$$

$$C_D = \left\{\frac{24}{N_{Res}}(1 + 0.15 N_{Res}^{0.678})\right\} \quad 3.7$$

$$N_{Re\,s} = \frac{\rho_{gL}(v_{gL} - v_s)d_s}{u_{gL}} \quad 3.8$$

$$v_{gL} = \frac{\propto_g v_g + \propto_L v_L}{\propto_{gL}} \quad 3.9$$

$$\propto_{gL} = \propto_g + \propto_L = 1 - \propto_s \quad 3.10$$

Where; u_{gL} internal energy of fluid, C_D drag coefficient, g gravitational acceleration, f_{gL} friction factor of gas liquid two-phase flow, $N_{Re\,s}$ Reynolds no. of cutting particles, d_s diameter of solid particles, F_D drag force between cuttings and fluid.

Energy equations

Energy equations are created for the fluids inside the drill string and in the wellbore annulus, and for heat transfer in the formation (Tian & Finger, 2000). The independent variable in the numerical scheme for heat transfer is measured depth and the vertical depth while the primary dependent variables are the temperatures inside the drill string, in the annulus and in the formation.

Inside drill string:

$$\frac{\partial}{\partial t}\left[\rho_{gL}\left(\mu_{gL} + \frac{v_{gL}^2}{2}\right)\right] + \frac{\partial}{\partial x}\left[\rho_{gL} v_{gL}\left(\mu_{gL} + \frac{p}{\rho_{gL}} + \frac{v_{gL}^2}{2} + gx\cos\theta\right)\right] = U_p(T_a - T_p) \quad 3.11$$

In annulus:

$$\frac{\partial}{\partial t}\left[\rho_{gL}\left(\mu_{gL}+\frac{v_{gL}^2}{2}\right)\right]+\frac{\partial}{\partial x}\left[\rho_{gL}v_{gL}\left(\mu_{gL}+\frac{p}{\rho_{gL}}+\frac{v_{gL}^2}{2}+gx\cos\theta\right)\right] = -U_p\left(T_a-T_p\right)+U_\propto\left(T_f-T_\propto\right)+Q_h \quad 3.12$$

In formation:

$$\rho_f C_{vf}\frac{\partial T_f}{\partial t}=K_f\left[\frac{1}{r}\frac{\partial}{\partial r}\left(r\frac{\partial T_f}{\partial r}\right)+\frac{\partial^2 T_f}{\partial z^2}\right] \quad 3.13$$

Where;

$$U_p = 2\pi\left[\frac{1}{h_p r_{pl}}+\frac{1}{K_p}In\left(\frac{r_{po}}{r_{pl}}\right)+\frac{1}{h_a r_{po}}\right]^{-1} \quad 3.14$$

$$U_\propto = 2\pi\left[\frac{1}{h_a r_1}+\frac{1}{K_1}In\left(\frac{r_2}{r_1}\right)+\frac{1}{K_2}In\left(\frac{r_3}{r_2}\right)+\cdots\right]^{-1} \quad 3.15$$

$$C_v = \propto_g C_{Vg} + \propto_L C_{VL} \quad 3.16$$

$$du_{gL} = C_V dT \quad 3.17$$

Where; p pressure, C_v specific heat at constant volume of fluid, C_{vf} specific heat at constant volume of formation, Q_h heat generation, r coordinate in radial direction, K_p thermal conductivity of drill string, K_f thermal conductivity of formation, x coordinate along measured well depth, h_a convective coefficient of fluid in annulus, h_p convective coefficient of fluid inside drill string, T_a temperature in annulus, T_f temperature in formation, T_p temperature inside drill string, t coordinate of time, U_{gL} internal energy of

fluid, f_{gL} friction factor of gas liquid two-phase flow, z vertical coordinate, a volume fraction, θ inclination angle of wellbore.

The Under-Balanced drilling of all four wells was simulated using the HUBS software described above. The Bottom Hole Assembly (BHA), the casing design and drilling fluid system used in the conventional drilling of the wells were adopted for the simulation exercise. For an effective Underbalanced drilling operation the annulus volume fraction for cuttings should be kept below 5% (SEC, 2012).

The parameters used in the simulation exercise were the geological formation of the wells and include from top; pyroclastics, Rhyolite, Basalt, Trachyte with alterations of basalt and Trachyte. Survey data also formed part of the input data. Tubular data for the wellbore, casing and drill string were also used (Appendix B to E). A mixture of air, water and foaming agent were the drilling fluids system. Well depths are taken either as true vertical depth or measured depth and for this exercise, the measured depth was utilized.

3.3 Project evaluation criteria

The benefits and the costs of the project were evaluated to determine whether the technology is economic or not. The criterion used was the benefit/cost ratio by first calculating the net present values and payback period. Equation 3.18 was used to calculate the Net Present Value (NPV) and equation 3.19 to calculate the Benefit Cost ratio. These evaluation criteria are all calculated in a different manner and they may not result in a consistent ranking of alternatives. The decision criteria was that if a benefit/cost ratio was greater than one, it indicates that the project was economic; and the higher the benefit/cost ratio was, the more economical the project was. Conversely, with a benefit/cost ratio of less than one, a project would be considered uneconomic. In choosing between mutually exclusive projects, the project with higher benefit cost ratio should be selected (Pearce, Atkinson, & Mourato, 2006).

$$Net\ Present\ Value\ (NPV) = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} - C_0 \qquad 3.18$$

$$Benefit\ Cost\ ratio = \frac{Present\ Value\ (Discounted\ Benefits)}{Present\ Value\ (Discounted\ Costs)} \qquad 3.19$$

3.4 Risk assessment

The International Association of Drilling Contractors (IADC) well classification (International Association of Drilling Contractors (IADC), Health Safety and Environment (HSE) subcommittee, 2003), formed an essential first step in the overall risk assessment. The next step in the assessment was the identification of potential hazards for Under-Balanced drilling in geothermal. Potential consequences to people, assets and the environment in relation to the probability of occurrence were also considered by the use of an assessment matrix categorizing the risks into low, medium and high. The hazards were analyzed using a Hazard Operability (HAZOP) analysis sheet. The IADC well classification (IADC, HSE subcommittee, 2003) is shown in tables 3.1, 3.2 and 3.3

Table 3.1: Application category

Category	Description
A	Managed Pressure Drilling (MPD) Drilling with returns to surface using an equivalent mud weight that is maintained at or above the open hole pore pressure.
B	Underbalanced Operations (UBO) Performing operations with returns to surface using an equivalent mud weight that is maintained below the open-hole pore pressure.
C	Mud Cap Drilling Drilling with a variable-length annular fluid column that is maintained above a formation that is taking injected fluid and drilled cuttings without returns to surface.

Table 3.2: Fluid systems

System	Fluid	Description
1	Gas	Gas as the fluid medium. No liquid intentionally added.
2	Mist	Fluid medium with liquid entrained in a continuous gaseous phase. Typical mist systems have less than 2.5% liquid content.
3	Foam	Two-phase fluid medium with a continuous liquid phase generated from the addition of liquid, surfactant and gas. Typical foam range from 55% to 97.5% gas.
4	Gasified liquid	Fluid medium with a gas entrained in a liquid phase.
5	Liquid	Fluid medium with a single liquid phase.

Table 3.3: Risk levels

Level	Description
0	Performance enhancement only; no hydrocarbon containing zones. Air drilling for ROP enhancement.
1	Well incapable of natural flow to surface. Well is inherently stable and is a low-risk from a well-control point of view. Sub-normally pressured oil wells.
2	Well is capable of natural flow to surface but can be controlled using conventional well kill methods. Catastrophic equipment failure may have limited consequences. Abnormally pressured water zones. Low flow rate oil or gas wells. Depleted gas wells.
3	Geothermal and non-hydrocarbon bearing formations. Maximum anticipated shut-in pressure (MASP) is less than UBO/MPD equipment pressure rating. Includes geothermal wells with H2S present.
4	Hydrocarbon bearing formation. Maximum anticipated shut-in pressure is less than UBO/MPD equipment operating pressure rating. Catastrophic equipment failure will likely have immediate serious consequences. High pressure and/or high flow potential reservoir, sour oil and gas wells, Offshore environments and Simultaneous drilling and production operations
5	Maximum anticipated surface pressure exceeds UBO/MPD equipment operating pressure rating. Catastrophic equipment failure will likely have immediate serious consequences. Any well where Maximum Anticipated Surface Pressure (MASP) is greater than UBO/MPD equipment pressure rating.

The risk assessment matrix used in the evaluation of the hazards is shown in Figure 3.1.

RISK ASSESSMENT MATRIX

PROBABILITY OF OCCURANCE

(Increasing probability)

POTENTIAL CONSEQUENCES		A Never heard of i the E & P n industry	B Has occurred in the E & P industry	C Has occurred in the UBD industry	D Likely to occur on this project	E Likely to occur several times on this project
1	People: Slight Injury or health effects Asset: Slight property damage < $10, 000 USD Environment: Slight effect					
2	People: Minor Injury or health effects Asset: Minor property damage < $100, 000 USD Environment: Minor effect					
3	People: Major Injury or health effects Asset: Localized damage < $1, 000, 000 USD Environment: Localized effect (onsite)					
4	People: Single Fatality or permanent total disability Asset: Major damage < $10, 000, 000 USD Environment: Major effect (offsite)					
5	People: Multiple fatalities Asset: Extensive damage > $10, 000, 000 USD Environment: Massive effect					

Figure 3.1: Risk assessment matrix (adapted from IADC, HSE Subcommittee, 2003)

CHAPTER FOUR

DATA ANALYSIS AND DISCUSSION OF RESULTS

4.1 Introduction

The analysis covers four geothermal wells; two wells are directional (OW 731A, OW 915B) and two vertical (OW 731, OW 804). An Under-Balanced drilling simulation exercise was carried out for the four wells. Under-Balanced drilling parameters like the volume fraction of the annulus, annulus velocities and the optimum circulation flow rate for effective hole cleanliness were determined. This chapter also indicates the payback period and the benefit cost ratio for the project. Potential risks associated with Under-Balanced drilling operations were also analyzed.

4.2 Simulation of Under-Balanced drilling operations

The simulation results for the annulus volume fractions and annulus velocities for the three phases in the fluid system were discussed. Comparison of the optimum circulation flow rate to the maximum cuttings concentration and minimum cuttings velocity were also discussed.

4.2.1 Annulus volume fraction

The cuttings volume fraction plots for all the wells shows a very slight decrease as the fluids travel up the well bore. The decrease may be resulting from the increase in gas influx which reduces the bottom hole pressure. The behavior of the plot is likely to be as a result of good transport of cuttings to the surface. The cuttings volume fraction in all wells simulated is below 5% of the total annulus volume as shown in Figure 4.1. This is in line with the cuttings recommendation for effective Under-Balanced drilling (SEC, 2012).

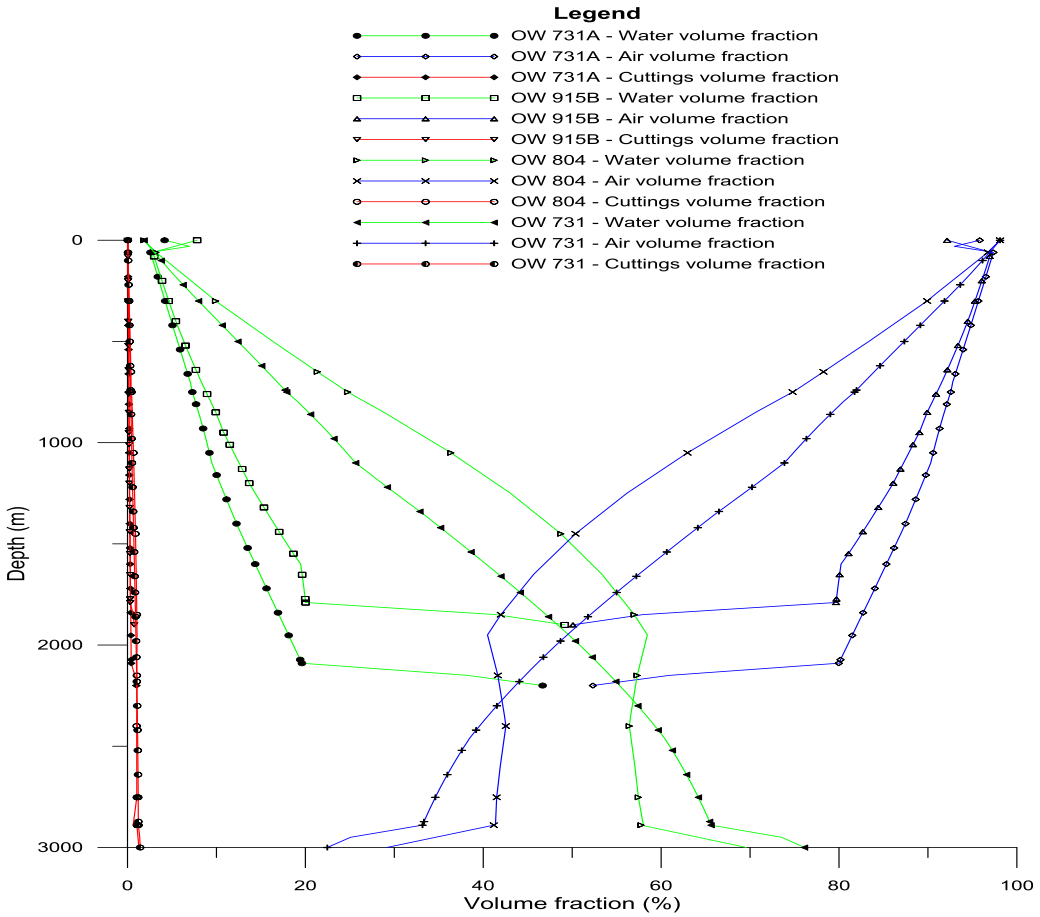

Figure 4.1: Annulus volume fraction profiles (Simulated UBD)

The volume fraction of water in all the wells decreases linearly from between 50 % and 77 % at deeper depths to between 5 % and 10 % at shallow depths as the fluid mixture travels to the surface. This could be as a result of the encounter of high temperature formations by the fluids thus leading to phase change or influx of formation gas. The air volume fraction in all the wells is increasing linearly from between 25 % and 50 % to at deeper depths to between 90 % and 95 % at shallow depths. This may be attributed to gas influx into the wellbore at various depths. The gas influx may also have a positive effect on the cuttings transport process reducing cuttings concentration as the fluids travel up the wellbore. The influx of gas increases the effective viscosity of foam which enhances cuttings lifting and transport ability of foam (Osunde & Kuru, 2008).

Circulation loss was experienced from shallow depths of 200 m to around 1700 m in the drilling of three of the sampled wells as shown in appendix G. A significant amount of time for the lost circulation was experienced for each well. Although, some of the lost circulation may be attributed to the local formation fractures, others are likely due to high pressures being applied into the well.

4.2.2 Annulus velocity profiles

Annulus velocities are key in determining the effects of the different fluid system components. The higher the cuttings velocity, the higher the wear rate of stripper rubber. If the velocities in the entire annulus are relatively high, the possibility is that the circulating flow rate(s) used could be well above the optimum circulating rates. Annulus velocities will vary depending on the type of drilling fluid in use. When using air and water, the cuttings velocity will be high as they leave the well due to rapid expansion of air at the exit. If foam is incorporated in the drilling fluid system, the velocities reduce due to the capability of foam bonding the water and air particles.

The velocities of the three components (Water, Air and cuttings) in the annulus in Figure 4.2 are increasing as the fluid mixture travel up the well bore. This may be due to change in diameter of the casings and accelerated inflow of formation fluids into the well bore thus increasing the velocities. The velocities of the cuttings and air also tend to increase rapidly towards the surface due to the rapid expansion of air while that of water is decreasing towards the exit.

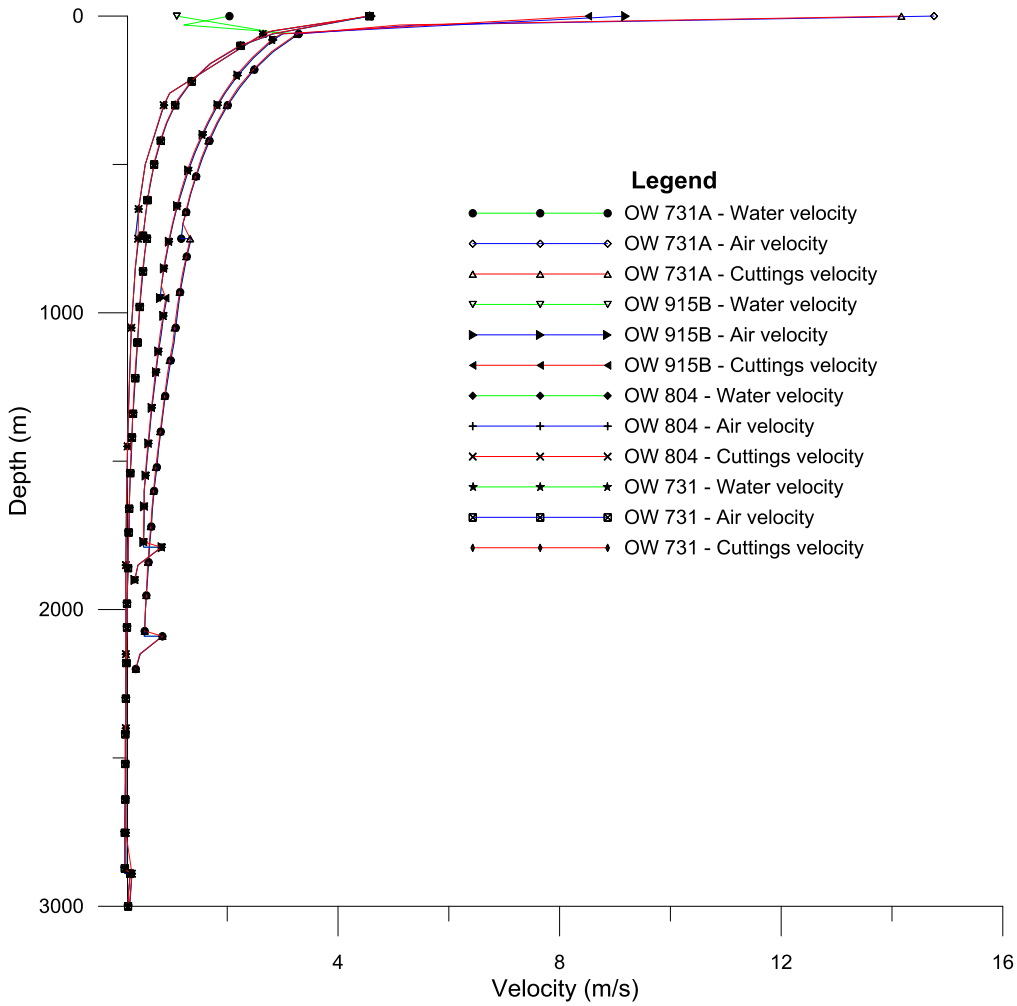

Figure 4.2: Annulus velocity profiles

4.2.3 Determination of the optimum circulation flow rate

The main reason for the determination of the optimum circulation flow rate is hole cleaning. Circulation of inadequate fluids causes cuttings accumulation inside the well bore, thus reducing drilling efficiency, creating down hole problems and increasing the weight of the fluid column inside the annulus. The heavy fluid column increases the bottom hole pressure and eventually result in an overbalanced condition. The fall back of cuttings due to insufficient circulation rates results in reduction of drilling efficiency caused by re – grinding of cuttings by the bit in a vertical well and the formation of a

cuttings bed along the section of a directional well. Circulating more fluid than required increases frictional pressure loss along the flow path, increased fluid handling equipment capacities, over consumption of power and increased erosion to the drill string and drilling equipments due the high velocities of cuttings. To maintain an under-balanced condition in the well bore requires that the drilling should operate at an optimal circulation rate and provide better hole cleaning, minimize power and equipment requirements.

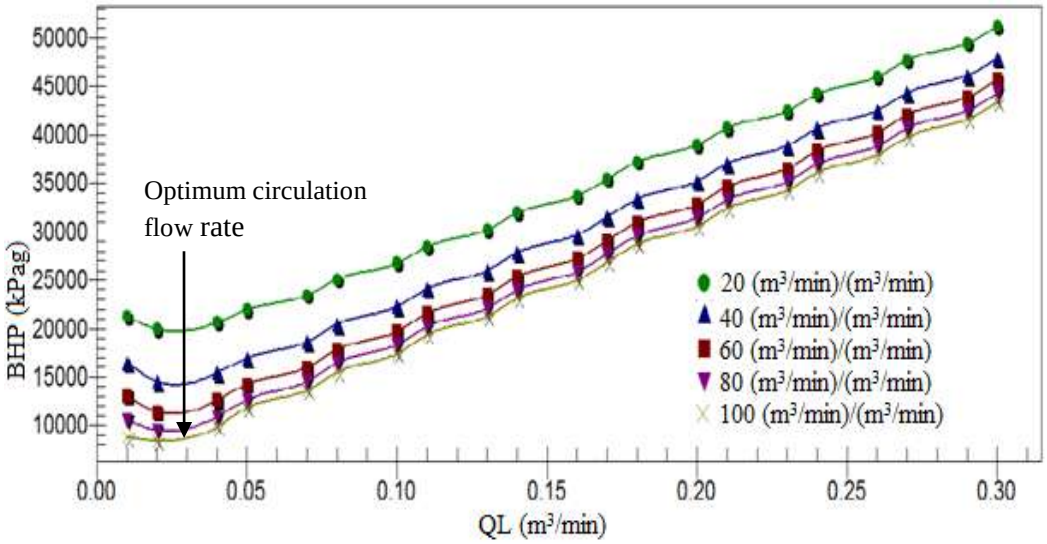

Figure 4.3: Optimum circulation flow rate (fixed air/water ratios)

The optimum circulation flow rate for sufficient hole cleaning is the flow rate which corresponds with the minimum bottom hole pressure. From Figure 4.3, the optimum circulation flow rate for water (QL) is 0.03 m^3/min. This flow rate is agreeing with the one obtained by Khezrian *et. al.* (2015) in the literature. According to Tian, Medley and Stone (2000) a typical optimum circulation flow rate curve has a minimum point and the curve has a steep gradient on the left side and a less steep gradient on the right side.

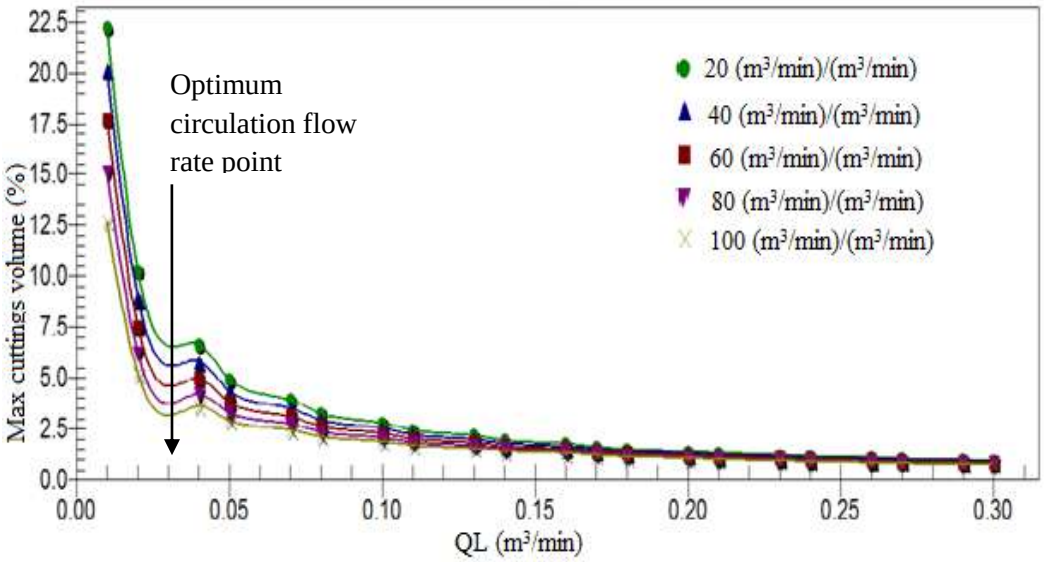

Figure 4.4: Maximum cuttings concentration (fixed air/water ratio)

Circulating at a rate below the optimum circulation flow rate point may result in a sharp increase of cuttings volume in the annulus as shown in Figure 4.4 and this translates into inability of the drilling fluid to effectively lift off the cuttings to the surface. Circulating at a rate above the optimum circulation flow rate point is likely to show that, the bottom hole pressure will increase due to liquid hold up in the annulus and reduces form quality which reduces the effective viscosity thus reducing the lifting and transport ability of foam (Osunde & Kuru, 2008). This might lead to the fall back of cuttings to the bottom of the hole or formation of cuttings bed.

In Figure 4.5, the velocity at the various fixed air flow rates is increasing with increase of the volume flow rate of water fraction. The velocities are increasing from between 0.02 m/sec and 0.08 m/sec at the optimum circulation flow rate to between 0.23 m/sec and 0.40 m/sec above the optimum circulation flow rate. This increase in cuttings velocity is detrimental to the drill string and well head equipment; therefore the optimum circulation flow rate should be maintained throughout the operation to avoid accelerated wear of components resulting from high velocities.

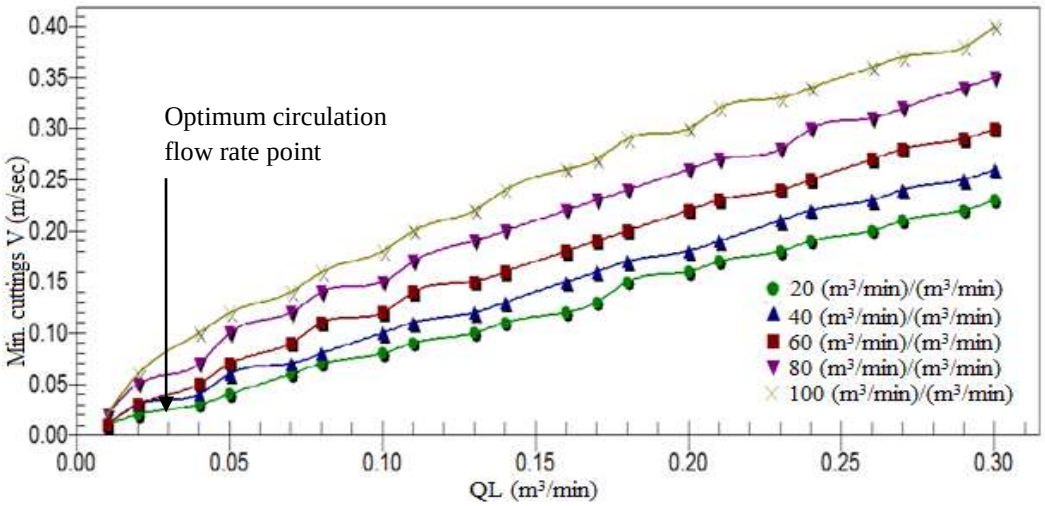

Figure 4.5: Minimum cuttings velocity

4.3 Economic assessment

The lost circulation and hole cleaning cost elements were tabulated from the daily drilling reports of the sampled wells. Hole cleanliness was picked as the major problem encountered during drilling operations of the wells. This section captures a few economic project evaluation criteria which were deemed substantial to this study.

4.3.1 Hole cleaning cost element

OW 731A analysis

The drilling of well OW 731A encountered loss of circulation fluids between 212 m to 353 m. Table 4.1 indicates cost of the lost circulation fluids. The loss of circulation fluids was more in the 17-1/2 inch hole than in the 12-1/4 inch hole. More water was lost into the formation in the 17-1/2 inch hole than in the 12-1/4 inch hole. Hole cleaning problems were also experienced between 234 m to 754 m and at 2842 m. The cost of the time spent circulating drilling fluids inside the well bore is tabulated in table 4.2. Circulation to ascertain hole cleanliness was majorly done between 200 m and 400 m, thus most of the circulation time cost is emanating from this depth range.

Table 4.1: Cost of lost circulation fluids

Hole size	Depth (Meter)	Circulation time (Hrs)	Fluid used	Qty used	Unit	Unit cost, USD	Total cost, USD
17 1/2"	212-234	35	Water	294	m^3	1.73	508.62
17 1/2"	212-234	4	Foam	0.240	m^3	1430	343.20
17 1/2"	200-239	4	Water	33.6	m^3	1.73	58.13
17 1/2"	239-246	2	Water	16.8	m^3	1.73	29.06
17 1/2"	246-247	1.5	Water	12.6	m^3	1.73	21.80
17 1/2"	258-267.80	5.5	Mud	2.772	Ton	220.83	612.14
17 1/2"	249.50-294.50	7	Mud	3.528	Ton	220.83	779.09
17 1/2"	294.50-325	12	Mud	6.048	Ton	220.83	1,335.58
12 1/4"	325-353	14	Water	117.6	m^3	1.73	203.448
12 1/4"	325-353	14	Foam	0.840	m^3	1430	1201.2
			Total				5,092.27

Table 4.2: Circulation time cost

Depth (m)	Circulation time (Hrs)	Total cost (USD)
234.00	9	14,400.00
200.00	1.00	1,600.00
239.00	12.5	20,000.00
246	37.00	59,200.00
252	2.00	3,200.00
256	2.00	3,200.00
258	9.50	15,200.00
264.89	1.00	1,600.00
267.8	16.00	25,600.00
275	1.00	1,600.00
294.5	30.00	48,000.00
313	3.00	4,800.00
324	5.00	8,000.00
353	10.00	16,000.00
372	6.50	10,400.00
400	15.00	24,000.00
377	1.00	1,600.00
754	11.00	17,600.00
2842	1.50	2,400.00
	Total	278,400.00

OW 915B analysis

The costs shown in table 4.3 could have been saved if monitored UBD operation was employed. From the table, it can be seen that the cost of drilling fluids which could have otherwise been re-circulated for drilling is totaling to USD 7,795.03. If the well was drilled using a monitored UBD operation these costs could have been saved. Circulation time data was not available for this well.

Table 4.3: Cost of lost circulation fluids

Depth (m)	Circulation time (Hrs)	Fluid used	Qty used (m^3)	Unit cost, USD	Total cost, USD
62-312	55	Water	462	1.73	799.26
1026-1175	30	Water	252	1.73	435.96
1026-1175	30	Soap	1.8	1400	2,520.00
1348-1484	20	Water	168	1.73	290.64
1348-1484	20	Soap	1.2	1400	1,680.00
1539-1606	21	Water	176.4	1.73	305.17
1539-1606	21	Soap	1.26	1400	1,764.00
		Total			7,795.03

OW 804 analysis

Circulation of insufficient fluids in the well bore leads to hole cleaning problems. In order to avert these problems in a conventional drilling case, fluids are circulated for a period of time so as to have all the cuttings transported to the surface. The conventional drilling of OW 804 had some of the drilling time spent doing circulation and the cost is as tabulated in table 4.4. The working charge rate per hour was taken as USD 1,600 (Moshe, 2013). Lost circulation fluids data was not available for this well.

Table 4.4: Circulation time cost

Depth (m)	Circulation time (Hrs)	Total cost (USD)
184.95	2.5	4,000.00
203.00	1.00	1,600.00
280.00	2	3,200.00
289.5	52.00	83,200.00
555	5.00	8,000.00
585.4	1.00	1,600.00
593	2.00	3,200.00
602.5	5.00	8,000.00
762	3.00	4,800.00
765	1.00	1,600.00
770	1.00	1,600.00
2043.6	1.00	1,600.00
2351.9	1.00	1,600.00
2771.45	1.00	1,600.00
2792	3.00	4,800.00
2869	2.00	3,200.00
2925	2.00	3,200.00
	Total	136,800.00

OW 731 analysis

Loss of circulation was experienced between 236.23 m and 723.46 m. The cost of the lost drilling fluids which could have been otherwise re-circulated for drilling is tabulated in table 4.5. Also the cost of the time spent to circulate drilling fluids to enhance hole cleaning is as shown in table 4.6.

Table 4.5: Cost of lost circulation fluids

Hole size	Depth (m)	Circulation time (Hrs)	Fluid used	Qty used (m^3)	Unit cost, USD	Total cost, USD
17 1/2"	236.23-299.50	183.75	Water	1543.5	1.73	2,670.26
17 1/2"	236.23-299.50	183.75	Foam	11.025	1430	15,765.75
17 1/2"	340.18-723.46	249	Water	2091.6	1.73	3,618.47
12 1/4"	340.18-723.46	249	Foam	14.940	1430	21,364.20
17 1/2"	1435-1697	70	Water	588	1.73	1,017.24
		Total				44,435.91

Table 4.6: Circulation time cost

Depth (m)	Circulation time (Hrs)	Total cost (USD)
299.50	2	3,200.00
334.00	2.00	3,200.00
347.36	1	1,600.00
356.57	11.00	17,600.00
385.64	1.00	1,600.00
403.5	1.00	1,600.00
424	3.00	4,800.00
675	1.00	1,600.00
723.46	2.00	3,200.00
	Total	38,400.00

A summary of the hole cleaning cost element analysis is as shown in Figure 4.6.

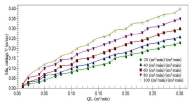

Figure 4.6: Summary of hole cleaning cost analysis

The cost element of the circulation time for well OW 731A is high compared to the rest of the wells. This could be partly attributed to insufficient transport of drill cuttings to the surface thus leading to the continuous circulation of fluids to ascertain hole cleanliness. The same well OW 731A has the lowest cost of circulation fluids incurred compared to the other three wells.

4.3.2 Economic evaluation criteria

The Under-Balanced drilling manual by Mclennan, Carden and Curry (1997) puts the increase in production from Under-Balanced drilling operations to be at least 10 % and decrease in development costs to be at least 10 %. In order to evaluate the present value of the money that will be pumped into project, three cases were considered. Case 1 is the drilling of four geothermal wells conventionally, case 2 takes into account the anticipated production increase of about 10 % after drilling the four wells using Under-Balanced drilling and also a possible decline in production of about 3 % per annum (Ngugi, 2013). The scenarios considered here do not take into account re-injection of

condensate to the geothermal system. Case 3 takes into account that Under-Balanced drilling improves drilling time and wells are completed faster. This faster drilling eventually results in a decrease of development cost of about 10 %. An average well cost of about USD 3.5 million and annual operation and maintenance cost of about Ksh 0.61/KWh (Ngugi, 2013) was used and the exchange rate used was Ksh 80/USD. Power take off price of Ksh 7.5/KWh and well head installation cost of USD 1.03 million/MW (Ronoh & Bwoma, 2013) was used in the three cases. The payback period and the benefit/cost ratio were also calculated so as to determine how economical the alternative is.

Case 1 (base case)

All four wells drilled in the first year with a conventional system

Table 4.7: Present worth of cash flow (Conventional drilling system case)

No.	Estimated future	Operation	Units	Years of operation			
				1	2	3	4
1	Net production (4wells) (average 5 Mw per well)		KWh, million	175.2	169.944	164.8457	159.9003
2	Gross income	(1)*7.5 Ksh	Ksh, million	1314	1274.58	1236.343	1199.252
3	Development costs (Well cost and power plant)		Ksh, million	1120	990	890	850
4	Annual O&M cost	(1) *Ksh 0.61	Ksh, million	106.872	103.6658	100.5559	97.53919
5	Cash flow	(2)-((3)+(4))	Ksh, million	87.128	180.9142	245.7867	251.7131
6	Annual present worth factor	((1+i)/(1+d))n		0.919643	0.845743	0.777782	0.715282
7	Present worth of cash flow	(5)*(6)	Ksh, million	80.12664	153.0069	191.1685	180.0458

The base case shown in Table 4.7 considers a field development and power plant construction period of two years and plant operation for four years. The reason for this was that, drilling four wells may take at most one year to complete and construction of well head units may take also one year to complete. The minimum average output of 5 Mw for wells in Olkaria was used in this exercise. Interest rate and discount rate were assumed to be 3 % and 12 % per annum. The net production was decreasing from 175.2 million KWh in the first year to 159.90 million KWh in the fourth year. This was as a result of the 3 % annual decline in production considered in the analysis. Similarly, the annual operation and maintenance cost was reducing from Ksh 106.87 million in the first year to Ksh 97.54 million in the fourth year. This reduction was also as a result of the production decline considered. The present worth of cash flows was increasing from Ksh 80.13 million in the first year to Ksh 180.05 million in the fourth year. The repayment of the development cost was amortized in four years in all the cases. The total present worth for this case was Ksh 604,347,800.

Case 2

Same as Case 1 with the exception that there is higher production due to reduced formation damage from UBD. A possible production increase of at least 10 % and an annual decline of 3 % in the field was evaluated for in this case as shown in Table 4.8. The base case and case 2 showed an increase in production from 175.2 million KWh to 192.72million KWh in the first year. However from year two to year four, there is a decline in production from 186.94 million KWh to 175.89 million KWh because re-injection of fluids was not considered in the analysis. Due to the production decline, the annual operation and maintenance cost reduced from Ksh 117.56 million in the first year to Ksh 107.29 million in the fourth year. The total present worth for four years was Ksh 974,142,700.

Table 4.8: Present worth of cash flow (higher production from UBD)

No.	Estimated future	Operation	Unit	Years of operation			
				1	2	3	4
1	Net production (4wells) (average 5 MW per well)		KWh, million	192.72	186.9384	181.3302	175.8903
2	Gross income	(1)*7.5 Ksh	Ksh, million	1445.4	1402.038	1359.977	1319.178
3	Development costs (Well cost and power plant)		Ksh, million	1220	890	890	850
4	Annual O&M cost(O&M cost is Ksh 0.61/KWh)	(1) *Ksh 0.61	Ksh, million	117.5592	114.0324	110.6115	107.2931
5	Cash flow	(2)-((3)+(4))	Ksh, million	107.8408	398.0056	359.3654	361.8844
6	Annual present worth factor	((1+i)/(1+d))n		0.919643	0.845743	0.777782	0.715282
7	Present worth of cash flow	(5)*(6)	Ksh, million	99.17502	336.6105	279.5079	258.8493

Case 3

Same as case 2 with the exception that development costs for the four wells are 10 % less, due to improved drilling while underbalanced. The anticipated decrease in development cost was 10 %. All other parameters were as for the previous cases as shown in Table 4.9.

Table 4.9: Present worth of cash flow (Reduced development cost from UBD)

No.	Estimated future	Operation	Unit	Years of operation			
				1	2	3	4
1	Net production (4wells) (average 5 Mw per well)		KWh, million	192.72	186.9384	181.3302	175.8903
2	Gross income	(1)*7.5Ksh	Ksh, million	1445.4	1402.038	1359.977	1319.178
3	Development costs (Well cost and power plant)		Ksh, million	1108	890	890	850
4	Annual O&M cost(O&M cost is Ksh 0.61/KWh)	(1) *Ksh 0.61	Ksh, million	117.5592	114.0324	110.6115	107.2931
5	Cash flow	(2)-((3)+(4))	Ksh, million	219.8408	398.0056	359.3654	361.8844
6	Annual present worth factor	((1+i)/(1+d))n		0.919642	0.845743	0.777782	0.715282
7	Present worth of cash flow	(5)*(6)	Ksh, million	202.1750	336.6105	279.5079	258.8493

The development cost reduction was reflected in year one and it was majorly on the cost of wells. The net production had the same reducing trend as in case 2 and the same applied to the annual operation and maintenance cost. However, the present worth of cash flow increased from Ksh 202.18 million in the first year to Ksh 258.85 million in the fourth year. For the four years evaluation period, the total present worth was Ksh 1,077,142,745. A summary of the present cash flows for the three cases is as shown in Figure 4.7.

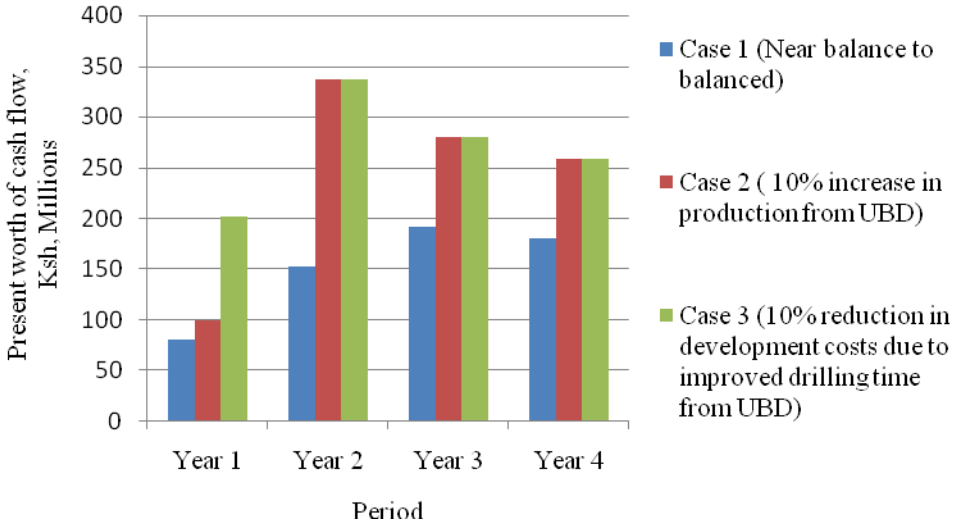

Figure 4.7: Present worth summary

In case 1, all four wells were drilled in the first year with a conventional system (Near balance to balanced). Case 2 is same as Case 1 with the exception that there is higher production due to reduced formation damage from UBD. Case 3 is same as case 2 with the exception that development costs for the four wells are 10 % less, due to improved drilling while underbalanced. Figure 4.7 shows the net present value projections for four years of plant operation. Case 3 has the highest total present worth and it is therefore the most economical.

Payback period

The period of time it will take to have all the investment cost recouped back was determined as shown in table 4.10. The approximate cost of a drilling rig was taken as Ksh 1 Billion and that of an additional UBD choke manifold as Ksh 0.08 Billion.

Table 4.10: Calculation of payback period

Initial investment (4 wells) and power plant	
Item	Cost (Ksh)
Development costs	2,008,000,000
UBD choke manifold	80,000,000
Power plant development (Well head generators)	1,650,000,000
Total	3,738,000,000

$$Payback\ period = \frac{Initial\ investment}{Cash\ inflow\ per\ period} = \frac{3{,}738{,}000{,}000}{818{,}293{,}444.83} = 4.6\ Years$$

Benefit /cost ratio

The criteria for an economical project also should have a benefit/cost ratio of greater than one. Table 4.11 shows how the ratio was obtained. Net Present Values were calculated as shown in appendix F. The life span of the plant was assumed to be 30 years. The total discounted cost for the conventional case was lower than that of Under-Balanced drilling case. This might have been as a result of additional cost of UBD equipment. However, the total discounted benefits for the UBD case was high compared to the conventional case. This might have been as a result of increased production from UBD. The under-balanced drilling case showed a high benefit/cost ratio of 1.40 while the conventional case showed a benefit/cost ratio of 1.25.

Table 4.11: Determination of the benefit cost ratio

		Conventional Drilling case	Under-Balanced Drilling case
Discounted construction cost (Construction period 2 years)			
Year 1	PVF (1 yr,12%) x cost in year 1	1,892,948,000.00	1,864,375,200.00
Year 2	PVF (2 yr,12%) x cost in year 2	1,315,380,000.00	1,315,380,000.00
Total discounted construction cost		3,208,328,000.00	3,179,755,200.00
Discounted operation and maintenance costs			
Calculate present value of annuity from year 3 to 32 PVA (30 Yr, 12%) x Annual O&M cost x PVF (2Yr, 12%)			
Total discounted operation and maintenance costs		575,099,969.37	623,985,507.38
Total discounted costs		3,783,427,969.37	3,803,740,707.38
Discounted benefits			
Calculate present value of annuity from year 3 to 32 PVA (30 yr, 12%) x annual benefit x PVF (2yr, 12%)			
Total discounted benefits		4,729,903,643.35	5,333,441,370.25
Benefit/cost ratio = PV (Discounted benefits)/PV (Discounted costs)		1.25	1.40

4.4 Risk assessment

Hazards likely to be associated with Under-Balanced drilling in geothermal have been identified and their potential consenquences are evaluated. The selected wells for the study are classified as level 3 with an application category B and fluid systems 3 and 4 according to the IADC well classification system.

4.4.1 UBD hazard identification

According to IADC HSE planning guidelines (2003), UBD hazards can be categorized as environmental, facility, health and project implementation issues. Some of the hazards which are associated with Under-Balanced drilling in geothermal were identified and it should be noted that, the current drilling practice of doing balanced drilling utilizes some of the equipment used in Under-Balanced drilling; therefore some of the hazards were identified from the current practice.

In UBD operations, compressors release blow downs to the environment. This blow down sometimes might contain traces of oil which may affect the soil negatively leading to environmental hazards. Uncontrolled well kicks from UBD operations may injure drilling crew on the rig floor. High velocity cuttings may lead to an increased wear rate of the rotating control head components and eventually penetrate into the rotary table causing bearings damage. In normal operation, the operation could sometimes vary from underbalanced to overbalanced state. Close coordination of the entire operation averts possible well kicks. The lines from the air compression system should be well anchored to avoid possible injuries to personnel and equipment. UBD operations might also lead to an increased exposure to toxic products like Hydrogen Sulphide (H_2S). Under-Balanced drilling in geothermal requires that the drilling crew be trained on how to effectively operate the compressed air system, how to ensure underbalanced condition continuously through a hole section, hazard recognition and management.

4.4.2 Initial Hazard Operability (HAZOP) analysis of Under-Balanced drilling in geothermal

The HAZOP analysis is a structured method of identifying hazards and operating problems of an expected or undergoing project. The HAZOP analysis is usually performed on a process or operation in an early phase in order to influence the design. However it is also applicable on existing operations or processes to identify

modifications that should be implemented in order to reduce risk and operability problems (International Electrotechnical Commission (IEC, 2001). Table 4.12 represents the initial analysis of hazard operability of Under-Balanced drilling operations in geothermal. The guide words used in each of the steps of the operation were adapted from(Engevik, 2007).

Table 4.12: Guide words

Guide word	Description
Unclear	Procedure is written in a hard way to understand and might be confusing
Step in wrong place	The procedure does not imply the correct sequence of actions that should be made
Wrong action	The action presented in the procedure is incorrect
Incorrect Information	Information that is checked prior to actions is incorrectly specified.
Step omitted	Step not performed
Step unsuccessful	The step is performed incorrectly
Interference effects from others	The procedure performance is affected by other personnel carrying out simultaneous tasks

HAZOP of an Under-Balanced drilling procedure

The procedure for Under-Balanced drilling involves the following steps;

1. Lift and Install Rotating Control Head (RCD)
2. Install flow line, separator and choke valve
3. Check compressor oil levels, open line valves and start compressors
4. Check mud tank water levels, pump oil level, open valves and start pump
5. Check drilling detergent tank level, pump oil level, open valves and start pump
6. Regulate choke valve as drilling continues

The score ratings shown below were adapted from Engevik (2007). The consequences related to each step were given a score according to safety and operability considerations.

- L = low, and was given the value 1
- M= medium, and was given the value 2
- H = high, and was given the value 3

To find the procedures with the strongest influence on the safety and operability, the average value of each procedure was calculated by using the score values of the consequences. The HAZOP data analysis sheet is shown in appendix A. The results from the analysis are as shown in the table 4.13.

Table 4.13: Results of HAZOP

	Procedure	Safety	Operability
Step 1	Lift and Install Rotating Control Head (RCD)	1.51	2.56
Step 2	Install flow line, separator and choke valve	1.53	2.53
Step 3	Check compressor oil levels, open line valves and start compressors	1.67	2.33
Step 4	Check mud tank water levels, pump oil level, open valves and start pump	1.50	2.25
Step 5	Check drilling detergent tank level, pump oil level, open valves and start pump	1.50	2.25
Step 6	Regulate choke valve as drilling continues	2.00	2.42

A summary of the results is shown in Figure 4.8.

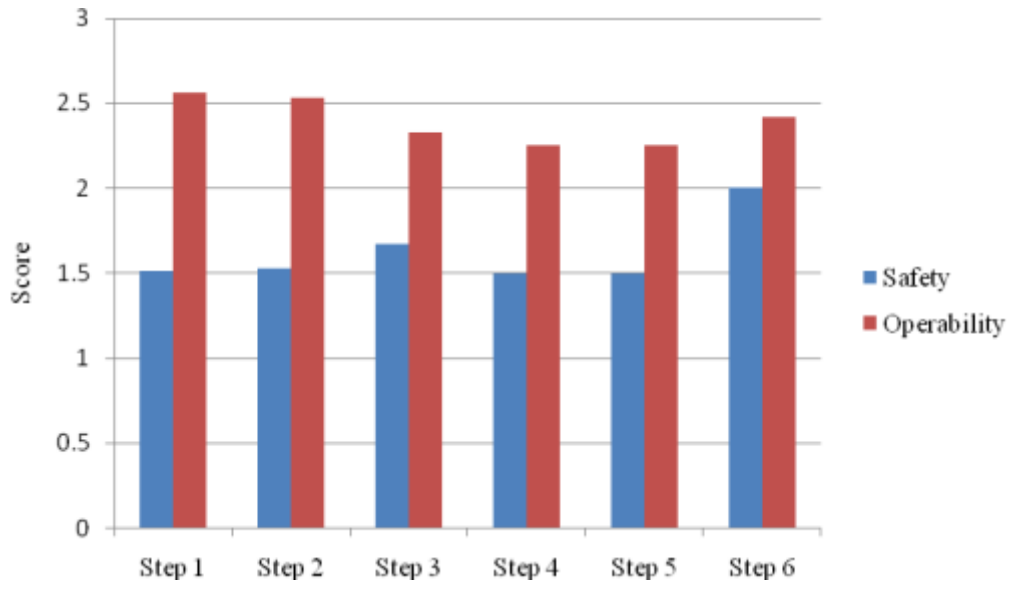

Figure 4.8: Summary of HAZOP results

Step 1 scored high in the operability aspect while step 6 scored high the safety aspect. The Rotating Control Device (RCD) is very key to the operation. The device diverts fluids to the flow line. If the RCD is not sealing off the well head, fluids leakage will occur and underbalanced conditions will be lost. The separator, flow line and the choke valve are also important in the procedure because they aid in the handling and manipulation of drilling fluid returns so as the required underbalanced bottom hole pressure is attained.

CHAPTER FIVE

CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The annulus volume fraction obtained for the cuttings was less than 5 % and this is in line with the recommendation for effective Under-Balanced drilling. An optimum circulation flow rate of 0.03 m^3/min was obtained for the liquid phase. Circulation of the liquid phase above the optimum circulation flow rate showed a decrease in cuttings volume. This situation may result in the distortion of foam quality thus affecting ability of foam to transport the cuttings effectively and it also increases the bottom hole pressure thus loosing underbalanced conditions. Circulation of the liquid phase below the optimum flow rate showed a sharp increase in cuttings volume. This situation might affect the drilling efficiency since cuttings may fall back to the bottom of the well thus leading to re-grinding of the cuttings in vertical wells and formation of cuttings bed in directional wells. Circulation above the optimum flow rate also showed an increase in cuttings velocity. This increase in velocity might may lead to increased wear of drill string and well head components. Hole cleaning and lost circulation cost elements for the wells sampled represented on average 3.7 % of the average well cost. Under-Balanced drilling scored a higher present worth compared to conventional drilling. The cost benefit ratio obtained for Under-Balanced drilling was 1.40 while the one obtained for conventional drilling was 1.25. The results of the two economic evaluation criterions depict Under-Balanced drilling as the more economical option. This evaluation did not consider the environmental cost generated by underbalanced drilling. In the initial HAZOP analysis of the UBD procedure, step one scored high in the operability aspect while step six scored high in the safety aspect.

5.2 Recommendations

Operators should fully consider utilization of Under-Balanced Drilling in the Olkaria geothermal field and other fields. Operators should also build capacity for carrying out Under-Balanced Drilling through the acquisition of additional equipment and training. More studies should be carried out to determine the suitable range of air flow rates which can be utilized without affecting the optimum flow rate for the liquid phase. More studies should also be done to establish the effects of varying the choke pressure to the bottom hole pressure and the determination of an optimum drilling rate to ascertain that bottom hole pressure is within the UBD window. Further work should be done to establish the environmental cost associated with Under-Balanced Drilling. This study also recommends that more simulation be done for Under-Balanced Drilling using other simulation software so as to compare the findings.

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APPENDICES

APPENDIX A: HAZOP ANALYSIS SHEET

							Consequence #	Safety	Operability
						Sheet:			
Procedure title: HAZOP OF UBD				Revision No:		Date			
Team composition						Meeting date			
Part considered			Instruction step						
No.	Step	Guideword	Deviation	Possible causes	Consequences	Action required	#	S	O
1	Lift and Install Rotating Control Head (RCD)	Unclear	RCD is in wrong position. The RCD is not lifted. Device is damaged	Wrong equipment is used because of unclear procedure, or RCD is moved too fast due to a confusing procedure.	1. The operation is delayed 2. Equipment is damaged	Find the position and tools that should be used during the lifting of the RCD, and make sure the procedure is clear and easy to understand.	1 2	L M	M H
2		Wrong action	RCD is left in	The wrong		Have a person	1	L	M

			wrong position.	torque is specified, either the torque given is too high or too low. The wrong tool is specified.	1.Leakage of drilling fluids 2.Equipment is damaged	check the procedures to make sure that the action stated in the procedure is correct.	2	M	H
3		Incorrect information	RCD is not well anchored	The RCD fasteners are not torqued	1.Leakage of drilling fluids 2.Equipment is damaged 3.Damaged gasket	Find the right torque for the fasteners	1 2 3	L M L	M H M
4		Step omitted	RCD is not installed.	Step is omitted in the procedure or by the operator.	1.Personnel injury resulting from high speed cuttings to the rig floor 2.Rotary table bearings damage 3.Electronic control	Review procedure	1 2 3 4	M M M L	H H H H

					instruments damage 4.Operation is delayed				
5		Step unsuccessful	RCD is not Installed in the right way.	Wrong action is performed by the operator.	1.Drilling fluids leakage 2.Equipment damage	Train personnel and double check the operation	1 2	L M	M H
6		Interference effects from others	RCD is incorrectly installed.	The operator is distracted, and fails take the right action.	1.Operation is delayed 2.Equipment is damaged	Train personnel and make sure that the work environment is good.	1 2	L M	M H
7	Install flow line, separator and choke valve	Unclear	Separator is in wrong position The separator, choke valve and flow line are not lifted	Wrong equipment is used because of unclear procedure, or separator, choke valve	1. The operation is delayed 2. Separator, choke valve and flow line are damaged	Find the position and tools that should be used during the lifting of the separator and flow line, and make sure the procedure is clear	1 2	L M	M H

			and are damaged	and flow line are moved too fast due to a confusing procedure.		and easy to understand.			
8		Wrong action	Separator, choke valve and flow line are left in wrong position.	The wrong height of separator platform is specified, The wrong flow line pipes are specified.	1.Leakage of drilling fluids 2.Operation is delayed	Have a person check the procedures to make sure that the action stated in the procedure is correct.	1 2	L M	M H
9		Incorrect information	Separator, choke valve and flow line are not well anchored	The turn buckle fasteners are not well tightened	1.Separator, choke valve and flow line vibrates, falls down and are damaged 2.Operation is delayed	Find the right adjustment for the turnbuckles	1 2	L M	M H
10		Step omitted	Separator,	Step is omitted	1.Personnel injury	Review procedure	1	M	H

			choke valve and flow line are not installed.	in the procedure or by the operator.	resulting from high speed cuttings to the rig floor .Electronic control instruments damage 3.Operation is delayed		2 3	L M	M H
11		Step unsuccessful	Separator, flow line and choke valve are not Installed in the right way.	Wrong action is performed by the operator.	1.Drilling fluids leakage 2.Separator, choke valve and flow line damage	Train personnel and double check the operation	1 2	L M	M H
12		Interference effects from others	Separator and flow line are incorrectly installed.	The operator is distracted, and fails take the right action.	1.Operation is delayed 2.Separator, choke valve and flow line are damaged	Train personnel and make sure that the work environment is good.	1 2	L M	M H

13		Unclear	Oil level is low and compressor might be damaged	Oil level mark not indicated and oil used is not the correct one	1. Operation delay 2. Equipment damage	Ensure that the minimum oil level mark is indicated and the correct oil type specified	1 2	L H	M H
14		Wrong action	Valves are left in wrong position	Correct valve opening position not shown	1.Back pressure to the compressor. 2.Valve gate wear Insufficient volume	Ensure that the fully open position of the valves is shown	1 2 3	L L L	M M M
15		Incorrect information	Valves are damaged or in incorrect position	Wrong valve positions might be given	1.Operation is delayed due to insufficient volumes	Give the right valve opening position	1	L	M
16	Check compressor oil levels and open line valves	Step omitted	The compressor will operate with wrong oil level	Oil level check is left in the procedure	1.Operation delay 2.Equipment damage	Train personnel on the start up procedures of the compressor	1 2	L H	M H
17		Step unsuccessful	Equipment is started with	Wrong action is performed	1.Equipment is damaged	Train personnel on the start up	1	H	H

			wrong oil level	by personnel		procedures of the compressor			
18		Interference effects from others	Valves are left in wrong position	Operator is distracted and fails to make the right decision	1.Operation is delayed 2.Valves are damaged	Train personnel and review work environment	1 2	L L	M M
19	Check mud tank water levels, pump oil level, open valves and start pump	Unclear	Water and oil levels are low and pump might be damaged	Water and oil levels mark not indicated	1. Operation delay 2. Equipment damage	Ensure that the minimum water and oil level marks are indicated and the correct oil type specified	1 2	L H	M H
20		Wrong action	Valves are left in wrong position	Correct valve opening position not shown	1.Back pressure to the pump. 2.Valve gate wear 3.Insufficient volume	Ensure that the fully open position of the valves is shown	1 2 3	L L L	M M M

21		Incorrect information	Valves are in incorrect position	Wrong valve positions might be given	1.Operation is delayed due to insufficient volumes	Give the right valve opening position	1	L	M
22		Step omitted	The pump will operate with wrong oil and water levels	Oil and water levels check is left in the procedure	1.Operation delay 2.Equipment damage	Train personnel on the start up procedures of the pumps	1 2	L H	M H
23		Step unsuccessful	Equipment is started with wrong oil and water levels	Wrong action is performed by personnel	1.Equipment is damaged 2.Operation is delayed	Train personnel on the start up procedures of the pumps	1 2	H L	H M
24		Interference effects from others	Valves are left in wrong position	Operator is distracted and fails to make the right decision	1.Operation is delayed 2.Valves are damaged	Train personnel and review work environment	1 2	L L	M M
25	Check drilling detergent	Unclear	Oil level is low and pump might	Drilling detergent and oil levels	1. Operation delay 2. Equipment damage	Ensure that the minimum drilling detergent and oil	1 2	L H	M H

	tank level, pump oil level,		be damaged	marks not indicated		level marks are indicated and the correct oil type specified			
26	open valves and start pump	Wrong action	Valves are left in wrong position	Correct valve opening position not shown	1.Back pressure to the pump. 2.Valve gate wear 3.Insufficient volume	Ensure that the fully open position of the valves is shown	1 2 3	L L L	M M M
27		Incorrect information	Valves are in incorrect position	Wrong valve positions might be given	1.Operation is delayed due to insufficient volumes	Give the right valve opening position	1	L	M
28		Step omitted	The pump will operate with wrong oil and drilling detergent levels	Oil and drilling detergent levels check is left in the procedure	1.Operation delay 2.Equipment damage	Train personnel on the start up procedures of the pumps	1 2	L H	M H
29		Step unsuccessful	Equipment is	Wrong action	1.Equipment is	Train personnel	1	H	H

			started with wrong oil and drilling detergent levels	is performed by personnel	damaged 2.Operation is delayed	on the start up procedures of the pumps	2	L	M
30		Interference effects from others	Valves are left in wrong position	Operator is distracted and fails to make the right decision	1.Operation is delayed 2.Valves are damaged	Train personnel and review work environment	1 2	L L	M M
31	Operate choke valve	Unclear	Valve is fully opened	Valve position mark not indicated	1. Underbalanced condition not achieved 2. Overbalanced condition	Ensure that the optimum valve positions for underbalanced conditions are indicated	1. 2.	L H	M H
32		Wrong action	Valve is left in wrong position.	The wrong valve position is specified, either the valve	1. High bottom hole pressure 2. Formation damage	Ensure that the valve is well regulated to achieve Under-	1 2 3	M H L	M H L

				is fully open or fully closed.	3. Loss of circulation	Balanced drilling conditions			
33		Incorrect information	The valve is in wrong position.	Wrong valve positions are given. The valve used does not have the capacity to handle drilling fluids.	1. Required back pressure is not attained 2. Overbalanced or balanced conditions	Review procedures and make sure right valve and positions are given.	1 2	L H	M H
34		Step omitted	Valve is left in wrong position	Adjustment of the valve is not done because the operation to adjust the valve is not performed, or left out in the	1. Required back pressure is not attained 2. Overbalanced or balanced conditions	Train personnel and review procedure to make sure all the steps in the operation are included.	1 2	L H	M H

				procedure.					
35		Step unsuccessful	Valve is left in wrong position.	Wrong action is performed by the personnel.	1. Required back pressure is not attained 2. Overbalanced or balanced conditions	Train personnel and make sure that the work environment is good.	1 2	L H	M H
36		Interference effects from others	Valve is left in wrong position.	Operator is distracted, and fails to make the right action.	1. Required back pressure is not attained 2. Overbalanced or balanced conditions	Train personnel and review the work environment.	1 2	L H	M H

APPENDIX B: INPUT DATA FOR HUBS OW 731A

Well Information										
Company		KENGEN								
Field		OLKARIA GEOTHERMAL FIELD								
Well Name		OW731A								
Date		8/18/2013								
Project		OLKARIA GEOTHERMAL FIELD								
Project No.										
AFE No.										
Location		NAIVASHA								
State/Province		RIFTVALLEY								
Country		KENYA								
Comments										
Operation Type		Land								
Circulating Fluids		Foam								
Circulation		Normal								
Formation										
Surface Temperature (°C)		30								

Formation										
Description	Bottom MD	Density	ROP	Bottom Temp.	Bottom Pore P.	Bottom Frac. P.	Influx/L. C.	PI Liquid	PI Gas	
	(m)	(g/cm³)	(m/hr)	(°C)	(kPag)	(kPag)		(m³/day/kPa/m)	(MMm³/day/kPa/m)	
Pyroclastics	30	1.8	1.8	0			None			
Rhyolite	700	2.58	3.3	45			L. C. only			
Basalt	1100	2.72	4.8	107			L. C. only			
Trachyte and basalt	1400	2.62	5.1	112			None			
Trachyte	1600	2.62	6.8	111			None			
Tachyte	3000	2.62	4.9	115			Both			
Well Trajectory										
Survey Data										
MD	Inclination	Azimuth								
(m)	(°)	(°)								
0	0	0								
806	2.43	42.74								
921	11.57	128.25								
987	21	131.89								
1124	23.28	130.06								
1152	23.39	127.02								
1331	23.54	133.39								

1460	22.49	132.97								
2376	21.05	134.69								
Tubular Data										
Casing/Wellbore										
Description	Top MD	Bottom MD	Casing OD	Casing ID	C. Roughness	Hole Size	H. Roughness			
	(m)	(m)	(mm)	(mm)	(mm)	(mm)	(mm)			
Surface	0	60	508	468.325	0.0003302	660.4	0.0254			
Anchor	0	300	339.725	315.341	0.0003302	444.5	0.0254			
Production	0	750	244.475	226.593	0.0003302	311.15	0.0254			
Open hole	750	3000				215.9	0.0254			
Drill string										
Description	Length	OD	ID	Roughness	CT	Input dp	dp	T.J. OD	T.J. ID	T.J. Interval
	(m)	(mm)	(mm)	(mm)			(kPa)	(mm)	(mm)	(m)
Drill collars	110.16	168.275	149.885	0.0003302				209.55	120.65	9.18
Heavu weight drill pipes	137.7	127	101.6	0.0003302				168.275	95.25	9.18
Drill pipes	2752.14	127	101.6	0.0003302				168.275	82.55	9.5
Flow Line										
Length	ID	Roughness								
(m)	(mm)	(mm)								
30	254	0.0254								
Fluids										
Liquid										

Name	Flow Rate	Density	Rheology	YP	Vis., PV, or K	Viscosity, PV, or K	n	Source		
	(m^3/min)	(kg/m^3)		(Pa)	(cp)	(Pa-s)				
Water	0.14	1000	Newtonian	0	2699.927	2.7	1	S. P. Injection		
Foam	0.001	1020	Newtonian	0	2999.919	3	1	S. P. Injection		
Gas										
Name	Flow Rate	Spec. Grav.	Source							
	(m^3/min)									
Air	30	1	S. P. Injection							
Parameters										
Max. Calculation Interval (m)			60							
Average Size of Cuttings (mm)			2							
Cuttings Sphericity (Sphere=1)			0.5							
Circulation Back Pressure (kPag)			0							
Measured Depth for Calculation (m)			2200							

APPENDIX C: INPUT DATA FOR OW 915B

Well Information										
Company		KENGEN								
Field		OLKARIA GEOTHERMAL FIELD								
Well Name		OW915B								
Date		8/18/2013								
Project		OLKARIA GEOTHERMAL PROJECT								
Project No.										
AFE No.										
Location		NAIVASHA								
State/Province		RIFVALLEY								
Country		KENYA								
Comments										
Operation Type		Land								
Circulating Fluids		Foam								
Circulation		Normal								
Formation										
Surface Temperature (°C)		21								
Formation										
Description	Bottom	Density	ROP	Bottom	Bottom Pore	Bottom	Influx/L.	PI Liquid	PI Gas	

	MD			Temp.	P.	Frac. P.	C.			
	(m)	(g/cm³)	(m/hr)	(°C)	(kPag)	(kPag)		(m³/day/kPa/m)	(MMm³/day/kPa/m)	
Pyroclastics	80	1.8	2.9	12	0	0	L. C. only			0
Rhyolite	400	2.58	4.3	20	0	0	L. C. only			0
Trachyte	700	2.62	3.2	22	0	0	L. C. only			0
Basalt and tuff	850	2.72	4	22	0	0	None			
Trachyte and rhyolite	1200	2.62	5.4	40	0	0	None			
Tachyte and tuff	1548	2.62	6.9	45	0	0	L. C. only			0
Rhyolite and trachyte	1600	2.58	8.6	45	0	0	None			
Trachyte and basalt	3000	2.62	3.5	240	0	0	L. C. only			0
Well Trajectory										
Survey Data										
MD	Inclination	Azimuth								
(m)	(°)	(°)								
0	0	0								
551	13.09	137.23								
864	19.4	139								
1010	21	140.6								
1919	21	140.7								
Tubular Data										

Casing/Wellbore										
Description	Top MD	Bottom MD	Casing OD	Casing ID	C. Roughness	Hole Size	H. Roughness			
	(m)	(m)	(mm)	(mm)	(mm)	(mm)	(mm)			
Surface	0	60	508	468.325	0.00033	660.4	0.0254			
Anchor	0	300	339.725	315.341	0.00033	444.5	0.0254			
Production	0	950	244.475	226.593	0.00033	311.15	0.0254			
Open hole	950	2842	0	0	0	215.9	0.0254			
Drillstring										
Description	Length	OD	ID	Roughness	CT	Input dp	dp	T.J. OD	T.J. ID	T.J. Interval
	(m)	(mm)	(mm)	(mm)			(kPa)	(mm)	(mm)	(m)
Drill collars	110.16	168.275	149.885	0.00033				209.55	120.65	9.18
Heavy weight drill pipes	137.7	127	101.6	0.00033				168.275	95.25	9.18
Drill pipes	2752.14	127	101.6	0.00033				168.275	82.55	9.5
Flow Line										
Length	ID	Roughness								
(m)	(mm)	(mm)								
30	200	0.00033								
Fluids										
Liquid										
Name	Flow Rate	Density	Rheology	YP	Vis., PV, or K	Viscosity, PV, or K	n	Source		

	(m^3/min)	(kg/m^3)		(Pa)	(cp)	(Pa-s)				
Water	0.14	1000	Newtonian	0	2699.927	2.7	1	S. P. Injection		
Foam	0.001	1020	Newtonian	0	2999.919	3	1	S. P. Injection		
Gas										
Name	Flow Rate	Spec. Grav.	Source							
	(m^3/min)									
Air	30	1	S. P. Injection							
Parameters										
Max. Calculation Interval (m)			60							
Average Size of Cuttings (mm)			2							
Cuttings Sphericity (Sphere=1)			0.65							
Circulation Back Pressure (kPag)			0							
Measured Depth for Calculation (m)			1900							

APPENDIX D: INPUT DATA FOR WELL OW 804

Well Information										
Company		KENGEN								
Field		OLKARIA GEOTHERMAL FIELD								
Well Name		OW 804								
Date		9/15/2013								
Project		OLKARIA GEOTHERMAL PROJECT								
Project No.										
AFE No.										
Location		NAIVASHA								
State/Province		RIFVALLEY								
Country		KENYA								
Comments										
Operation Type		Land								
Circulating Fluids		Foam								
Circulation		Normal								
Formation										
Surface Temperature (°C)		25								
Formation										

Description	Bottom MD	Density	ROP	Bottom Temp.	Bottom Pore P.	Bottom Frac. P.	Influx/L. C.	PI Liquid	PI Gas	
	(m)	(g/cm³)	(m/hr)	(°C)	(kPag)	(kPag)		(m³/day/kPa/m)	(MMm³/day/kPa/m)	
Pyroclastics	50	1.8	3.3	6.7			None			
Rhyolite	650	2.58	3.6	23			L. C. only			
Basalt and tuff	850	2.72	3.3	27.4			L. C. only			
Trachyte	1950	2.62	8.4	89.4			None			
Trachyte and Rhyolite	2400	2.62	4.9	182.7			L. C. only			
Tachyte	3000	2.62	4.2	259.2			L. C. only			
Well Trajectory										
Vertical Well										
Tubular Data										
Casing/Wellbore										
Description	Top MD	Bottom MD	Casing OD	Casing ID	C. Roughness	Hole Size	H. Roughness			
	(m)	(m)	(mm)	(mm)	(mm)	(mm)	(mm)			
Surface Casing	0	60	508	468.325	0.0003302	660.4	0.0254			
Anchor	0	300	339.725	315.341	0.0003302	444.5	0.0254			

Production	0	750	244.475	226.593	0.0003302	311.15	0.0254			
Open Hole	750	3000				215.9	0.0254			
Drill string										
Description	Length	OD	ID	Roughness	CT	Input dp	dp	T.J. OD	T.J. ID	T.J. Interval
	(m)	(mm)	(mm)	(mm)			(kPa)	(mm)	(mm)	(m)
Drill collars	110.16	168.275	149.885	0.0003302				209.55	120.65	9.18
Heavy weight drill pipes	137.7	127	101.6	0.0003302				168.275	95.25	9.18
Drill pipes	2752.14	127	101.6	0.0003302				168.275	82.55	9.5
Flow Line										
Length	ID	Roughness								
(m)	(mm)	(mm)								
30	200	0.0003302								
Fluids										
Liquid										
Name	Flow Rate	Density	Rheology	YP	Vis., PV, or K	Viscosity, PV, or K	n	Source		
	(m^3/min)	(kg/m^3)		(Pa)	(cp)	(Pa-s)				
Water	0.14	1000	Newtonian	0	2699.9268	2.7	1	S. P. Injection		
Foam	0.001	1020	Newtonian	0	2999.9186	3	1	S. P. Injection		

Gas										
Name	Flow Rate	Spec. Grav.	Source							
	(m^3/min)									
Air	10	1	S. P. Injection							
Parameters										
Max. Calculation Interval (m)			200							
Average Size of Cuttings (mm)			2							
Cuttings Sphericity (Sphere=1)			0.65							
Circulation Back Pressure (kPag)			0							
Measured Depth for Calculation (m)			3000							

APPENDIX E: INPUT DATA FOR WELL OW 731

Well Information										
Company		KENGEN								
Field		OLKARIA GEOTHERMAL FIELD								
Well Name		OW731								
Date		8/18/2013								
Project		OLKARIA GEOTHERMAL PROJECT								
Project No.										
AFE No.										
Location		NAIVASHA								
State/Province		RIFVALLEY								
Country		KENYA								
Comments										
Operation Type		Land								
Circulating Fluids		Foam								
Circulation		Normal								
Formation										
Surface Temperature (°C)		30								

Formation										
Description	Bottom MD	Density	ROP	Bottom Temp.	Bottom Pore P.	Bottom Frac. P.	Influx/L. C.	PI Liquid	PI Gas	
	(m)	(g/cm³)	(m/hr)	(°C)	(kPag)	(kPag)		(m³/day/kPa/m)	(MMm³/day/kPa/m)	
Pyroclastics	100	1.8	0.4	30			None			
Rhyolite	500	2.58	0.9	65			L. C. only			
Trachyte	800	2.62	1.7	90			L. C. only			
Rhyolite	1100	2.58	6.3	130			Both			
Basalt	1360	2.72	4.1	120			Both			
Tachyte	1740	2.62	7.9	115			Both			
Basalt and Trachyte	2000	2.72	4.193548	112			Both			
Trachyte	2460	2.62	4	110			Both			
Trachyte	3000	2.62	4.285714	120			Both			
Well Trajectory										
Vertical Well										
Tubular Data										
Casing/Wellbore										
Description	Top MD	Bottom MD	Casing OD	Casing ID	C. Roughness	Hole Size	H. Roughness			
	(m)	(m)	(mm)	(mm)	(mm)	(mm)	(mm)			
Surface casing	0	60	508	468.325	0.0003302	660.4	0.0254			
Anchor	0	300	339.725	315.341	0.0003302	444.5	0.0254			

Production	0	750	244.475	226.593	0.0003302	311.15	0.0254			
Open hole	750	3000				215.9	0.0254			
Drill string										
Description	Length	OD	ID	Roughness	CT	Input dp	dp	T.J. OD	T.J. ID	T.J. Interval
	(m)	(mm)	(mm)	(mm)			(kPa)	(mm)	(mm)	(m)
Drill collars	110.16	168.275	149.885	0.0003302				209.55	120.65	9.18
Heavy weight drill pipes	137.7	127	101.6	0.0003302				168.275	95.25	9.18
Drill pipes	2752.14	127	101.6	0.0003302				168.275	82.55	9.5
Flow Line										
Length	ID	Roughness								
(m)	(mm)	(mm)								
30	200	0.003302								
Fluids										
Liquid										
Name	Flow Rate	Density	Rheology	YP	Vis., PV, or K	Viscosity, PV, or K	n	Source		
	(m^3/min)	(kg/m^3)		(Pa)	(cp)	(Pa-s)				
Water	0.14	1000	Newtonian	0	2699.927	2.7	1	S. P. Injection		
Foam	0.001	1020	Newtonian	0	2999.919	3	1	S. P. Injection		
Gas										
Name	Flow Rate	Spec. Grav.	Source							
	(m^3/min)									

Air	10	1	S. P. Injection							
Phase Change Calculation			None							
Parameters										
Max. Calculation Interval (m)			60							
Average Size of Cuttings (mm)			2							
Cuttings Sphericity (Sphere=1)			0.65							
Circulation Back Pressure (kPag)			0							
Measured Depth for Calculation (m)			3000							

APPENDIX F: NET PRESENT VALUE FOR BENEFIT B/C RATIO

Year			1	2	3	4	5	6	7	8	9	10	11	12	13	14
Estimated future	Operation	Units														
(1) Net production (4wells) (average 5 Mw per well)		KWh, million	192.72	186.938	181.330	175.890340	170.613	165.495	160.530	155.714	151.043	146.511	142.116	137.852	133.717	129.705
(2) Gross income	(1)*7.5Ksh	Ksh, million	1445.4	1402.04	1359.98	1319.17755	1279.60	1241.21	1203.98	1167.86	1132.82	1098.84	1065.87	1033.90	1002.88	972.793
(3) Development costs (Well cost and power plant)		Ksh, million	1108	890	890	850	0	0	0	0	0	0	0	0	0	0
(4) Annual O&M cost(O&M cost is Ksh 0.61/Kwh)	(1) *Ksh 0.61	Ksh, million	117.5592	114.032	110.612	107.293108	104.074	100.952	97.9235	94.9858	92.1362	89.3722	86.691	84.0903	81.5676	79.1205
(5) Cash flow	(2)-((3)+(4))	Ksh, million	219.8408	398.006	359.365	361.884447	1175.53	1140.26	1106.05	1072.87	1040.69	1009.47	979.182	949.806	921.312	893.673
(6) annual present worth factor	((1+i)/(1+d))n		0.91964	0.84574	0.77778	0.71528164	0.65780	0.60495	0.55633	0.51163	0.47052	0.43271	0.39794	0.36596	0.33655	0.30951
(7) Present worth of cash flow	(5)*(6)	Ksh, million	202.175	336.6105	279.507	258.84930	773.266	689.795	615.334	548.911	489.658	436.801	389.650	347.589	310.068	276.597

APPENDIX G: ACTUAL NEAR BALANCE TO BALANCED DRILLING

Circulation loss							
Well OW 731A		Well OW 915B		Well OW 731		Well OW 804	
Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)
212-234	35	62-312	55	236.23-299.50	183.75	-	-
212-234	4	1026-1175	30	236.23-299.50	183.75	-	-
200-239	4	1026-1175	30	340.18-723.46	249	-	-
239-246	2	1348-1484	20	340.18-723.46	249	-	-
246-247	1.5	1348-1484	20	1435-1697	70	-	-
258-267.80	5.5	1539-1606	21	-	-	-	-
249.50-294.50	7	1539-1606	21	-	-	-	-
294.50-325	12	-	-	-	-	-	-
325-353	14	-	-	-	-	-	-
325-353	14	-	-	-	-	-	-
Increased hole cleaning circulation							
Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)	Depth (M)	Time taken (Hrs)

234.00	9	-	-	299.50	2	184.95	2.5
200.00	1.00	-	-	334.00	2.00	203.00	1.00
239.00	12.5	-	-	347.36	1	280.00	2
246	37.00	-	-	356.57	11.00	289.5	52.00
252	2.00	-	-	385.64	1.00	555	5.00
256	2.00	-	-	403.5	1.00	585.4	1.00
258	9.50	-	-	424	3.00	593	2.00
264.89	1.00	-	-	675	1.00	602.5	5.00
267.8	16.00	-	-	723.46	2.00	762	3.00
275	1.00	-	-	-	-	765	1.00
294.5	30.00	-	-	-	-	770	1.00
313	3.00	-	-	-	-	2043.6	1.00
324	5.00	-	-	-	-	2351.9	1.00
353	10.00	-	-	-	-	2771.45	1.00
372	6.50	-	-	-	-	2792	3.00
400	15.00	-	-	-	-	2869	2.00
377	1.00	-	-	-	-	2925	2.00
754	11.00	-	-	-	-	-	-
2842	1.50	-	-	-	-	-	-