EFFECT OF PRESSURE AND TEMPERATURE DISTRIBUTION TO THE DRILLING FLUID DENSITY FOR MANAGED PRESSURE DRILLING (MPD) APPLICATIONS

BY

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Dissertation Submitted in Partial Fulfillment of the Requirement for the Bachelor of Engineering (Hons) in Petroleum Engineering

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Universiti Teknologi PETRONAS

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CERTIFICATION OF APPROVAL

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(PETROLEUM ENGINEERING)

Approved by,

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TRONOH, PERAK

December 2012

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

(Mohd Sallehudin Bin Abdullah, ID: 12029)

ABSTRACT

Drilling fluid performance is a major component that contributes to the drilling operations' success. This fluid is mainly used to promote borehole stability, removing drilled cuttings from borehole, cool and lubricate the bit and drill string, and to control the subsurface pressure. The effects of the temperature and pressure conditions prevalent in high temperature/high pressure wells with narrow operating windows on the equivalent circulating density (ECD) of drilling fluids in a circulating wellbore as well as the bottom-hole pressure are studied in this paper. High temperature conditions cause the fluid in the wellbore to expand, while high pressure conditions in deep wells cause fluid compression. Inappropriate consideration of these two opposing effects may result inaccurate estimation of bottom-hole pressure with incorrect application of Managed Pressure Drilling (MPD) techniques. The rheological properties of drilling fluids especially density of oil/synthetic based mud changes significantly in high pressure/temperature wells. This study was to determine the rheological properties of drilling fluids using empirical model from the experiments and simulated the ECD and bottom-hole circulating pressure with pressure and temperature as the main parameters. Paraffin based synthetic drilling fluid was used for this purpose and a simulator called Landmark® WellPlan was used to simulate the wellbore during circulation. A Bingham Plastic model was implemented to express the rheological behavior of the drilling fluid studied, with rheological properties expressed as functions of pressure and temperature. The applied backpressure, circulating times, and pump rates are used as variables in the simulation in order to simulate the ECD, bottom-hole circulating pressure and temperature profiles in the wellbore conditions. The results of the simulation show that higher pump rates lead to higher ECD and circulating pressure in the wellbore with higher pressure drop across the bit towards fracture gradient in the operating window. The circulating times for drilling fluids gives a significant effect on the ECD, circulating pressures, and temperature profile along the wellbore. The MPD application was simulated with the application of backpressure gives in higher ECD and circulating pressure at bottom-hole condition using optimum pump rate. The ECD and circulating pressure profile for paraffin synthetic based mud is strongly influenced by the effect of pressure and temperature during MPD applications.

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I would also like to thank to Universiti Teknologi PETRONAS and laboratory staff technicians for supporting this project research by providing laboratory software and assist in software applications. I would also like to thank my project coordinators, AP Aung Kyaw and Dr Abdel Aziz who dedicatedly provided additional support and encouragement throughout the final year semester. Lastly, this project was dedicated to family, friends, lecturers and staffs who have directly and indirectly involved helping me throughout my project research.

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ABBREVIATIONS

MPD	Managed Pressure Drilling
ECD	Equivalent Circulating Density
ESD	Equivalent Static Density
YP	Yield Point
CBHP	Constant Bottom Hole Pressure
NPT	Non-Productive Time
HPHT	High Pressure High Temperature
PVT	Pressure Volume Temperature
WBM	Water Based Mud
OBM	Oil Based Mud
PWD	Pressure While Drilling
RCD	Rotating Control Device
HSE	Health Safety Environment
BHA	Bottom-Hole Assembly
ROP	Rate of Penetration
IADC	International Association of Drilling Contractors

NOMENCLATURE

ρ = density of drilling fluid, ppg

h = height of static fluid column, ft

τ = shear stress

τ_y = yield stress, lb/100sqft

μ_P = plastic viscosity, cp

γ = shear rate, sec^{-1}

A = regression coefficient in equation (3.1)

B = regression coefficient in equation (3.1)

C = regression coefficient in equation (3.3)

D = regression coefficient in equation (3.3)

Y = regression coefficient in equation (3.6)

ρ_i = regression coefficient in equation (3.6)

P = pressure, psi

T = temperature, °F

ρ_{esd} = equivalent circulating density, ppg

$\Delta P_{hydrostatic}$ = hydrostatic pressure gradient

$\Delta P_{friction}$ = frictional pressure loss

ρ_{o1}, ρ_{w1} = density of oil and water at temperature T_1 and pressure P_1

ρ_{o2}, ρ_{w2} = density of oil and water at temperature T_2 and pressure P_2

f_{vo}, f_{vw}, f_{vs}, f_{vc} = fractional volume of oil, water, solid weighting material, and chemical additives

P_1, P_2 = pressure at reference and condition “2”

T_1, T_2 = temperature at reference and condition “2”

F = force

A = area in contact with the fluid subjected to the force

CHAPTER 1

INTRODUCTION

1.1 Background Study

Drilling fluid performance is a major factor that contributes to the drilling operation's success. The properties of the drilling fluid such as equivalent circulating density (ECD), equivalent static density (ESD) and rheological properties always assumed to be constant during the operation. This assumption can prove to be incorrect in high pressure/temperature wells with pressure and temperature variations. Drilling operations in the formation with narrow gap between pore and fracture pressure margins are very impossible to be done using conventional drilling method, with the slight change in bottom-hole pressure conditions can lead to an increase in the Non-Productive Time (NPT) caused by kick or fluid loss with possible blowout occurrence.

For these reasons, a new technique has been introduced under Managed Pressure Drilling (MPD) called Constant Bottom Hole Pressure (CBHP). Managed Pressure Drilling (MPD) is an adaptive drilling process used to precisely control the annular pressure profile throughout wellbore (Vieira P., 2009). This technique enables the drilling operation continued with the bottom-hole pressure is maintained constant whether the fluid column is static or circulating. This concept referred to 'walking the lines' between pore pressure and fracture pressure gradients. The loss of annulus flowing pressure when not circulating is counteracted by applied surface backpressure. According to J. Shubert (2009), the basic concept of Constant Bottom Hole Pressure (CBHP) is to accurately determine the change in bottom-hole pressure caused by dynamic effects and compensate with an equal change in annular wellhead pressure. For this application, it requires better wellbore pressure management and correct planning on the drilling fluid design to be implemented.

As the total vertical depth increases, there is an increase in the bottom-hole temperature and hydrostatic head of fluid column. These parameters have opposing effect on ECD (Mc. Mordie et al., 1982). An increase in hydrostatic pressure cause increase in ECD due to compression but an increase in the temperature causes a reduction in ECD due to the thermal expansion. Usually these effects are assumed to be canceling each other out in conventional drilling but for MPD applications, it was very significant and precise estimation of static and dynamic equivalent density is of essential importance for the drilling operation through narrow operation window wells

1.2 Problem Statement

During the drilling process, the drilling fluid temperature is not constant due to the thermal phenomena present during circulation of the drilling fluid. There is heat transfer from the formation to the drilled hole due to the difference between geothermal and drilling fluid temperatures. According to E. Karstad et al (1998), the drilling fluid density is strongly affected by the formation temperature and annular pressure. The type of drilling fluid plays an important role in drilling fluids behavior with changes in temperature and pressure profile. Considering the thermal expansion and pressure compression effect, the rheological properties especially density of oil/synthetic based drilling fluids, changes significantly in high pressure/high temperature (HPHT) wells (Courtesy of Mullen et al., 2001).

Hydrostatic pressure calculation in deep wells, with high bottom-hole pressure and temperature, requires a correction for the fluid density of each interval of the hole. Increasing temperature decreases the density of fluid, while increase pressure increases fluid density. This phenomenon may be significant in Managed Pressure Drilling as this technique used pressure control system as the main indicators to control the bottom-hole pressure keep constant while drilling operation especially for narrow operating window wells.

With the significant changes in drilling fluid density in term of equivalent circulating density and circulating pressure, the fluid rheology and flow rate should be considered in order to predict the pressure loss throughout circulation system (Bazer D., 1991). Equivalent circulating density is become very important to be monitored especially in HPHT wells due to the effect of pressure and temperature profile in order to avoid kicks and losses.

The changes in equivalent circulating density due to the effect of pressure and temperature during drilling operation brings some of the significant problems in annular pressure profile result in loss circulation of drilling fluids to the formation and invasion of the formation fluid into the wellbore. Without the proper consideration of these effects, it may result in an accurate estimation of bottom-hole pressures and incorrect application of MPD techniques as the reference values are not precise, in consequences dealing with increase in Non- Productive Time (NPT). The precise determination of all effects on density reduction by the formation pressure and temperature lead to minimize the uncertainty when controlling drilling problems.

1.3 Objectives

1.3.1 To determine the rheological properties such as plastic viscosity (μ_P) and yield point (τ_Y) of n-paraffin oil based mud as drilling fluid used with mud weight 14.6 ppg by using rheological modeling.

1.3.2 To simulate the equivalent circulating density (ECD) and circulating pressure with pressure and temperature variations as the main parameters for Managed Pressure Drilling (MPD) applications using Landmark® Wellplan.

1.4 Scope of Study

The study which is carried out in this project is to determine the effect of pressure and temperature distribution to the rheological properties in term of density for n-paraffin oil based mud. The rheological properties of drilling fluids such as plastic viscosity and yield point are modeled using empirical model in term of pressure and temperature. A Bingham Plastic model was used as the fluid rheological model for this drilling fluid in order to determine the rheological properties. This empirical model is used for precise correlation with the data using HPHT viscometer and Mercury Free PVT system experiment to show the relationship of rheological parameters for n-paraffin oil based mud. This model included the determination of rheological properties (plastic viscosity and yield point) and the fluid density changes with pressure and temperature as the parameters. The data for rheological modeling was then used in the simulation of the ECD and circulating pressure.

The equivalent circulating density (ECD) and circulating pressure are determined using simulation by Landmark® Wellplan with the different pressure and temperature distributions. These two parameters are very important as it indicates the hydrostatic pressure applied by drilling fluids to the formation at certain depth during drilling operation. Other parameters also used in the simulation in order to generate ECD, circulating pressure and temperature profile for specific scenario such as circulating times, pump rates and backpressures.

The scope of study is mainly to determine the equivalent circulating density and circulating pressure with down-hole variations in pressure and temperature for Managed Pressure Drilling applications and the use of rheological modeling to predict the fluid rheology behavior. In this project, author proposed to use n-paraffin oil based mud as drilling fluids to determine the ECD and circulating pressure under variations of pressure and temperature.

CHAPTER 2
LITERATURE REVIEW

The objective of this section is to review the literature in several areas related to the objectives of the study. In order to accomplish the objective, previous researches and studies were cited to gain knowledge and basic ideas about the project. Numerous publications and researches have dealt with the behavior of density of drilling fluids in response to variations in pressure-temperature conditions. Various models have been proposed in order to characterize this relationship, with some models being empirical in nature, and others compositional. The compositional model characterizes the volumetric behavior of drilling fluids based on the behavior of the individual constituents of the drilling fluid.

In the compositional model, the density of any solids content in the drilling fluid is taken to be independent of temperature and pressure. It is assumed that any change in density is due to density changes in the liquid phases. It is also assumed that there are no physical and chemical interactions between the solid and liquid phases in the drilling fluid. Hoberock *et al* proposed the following compositional model for equivalent static density of drilling fluids.

$$\rho(P_2, T_2) = \frac{\rho_{o1} f_{vo} + \rho_{w1} f_{vw} + \rho_s f_{vs} + \rho_c f_{vc}}{1 + f_{vo}\left(\frac{\rho_{o1}}{\rho_{o2}} - 1\right) + f_{vw}\left(\frac{\rho_{w1}}{\rho_{w2}} - 1\right)} \quad \text{…………..} \ (2.1)$$

Application of the compositional model requires some knowledge of how the densities of each liquid phase in the mud, usually water and some type of hydrocarbon, change with changes in temperature and pressure. The static mud density at elevated pressure and temperature can be predicted from knowledge of mud composition, density of constituents at ambient or standard temperature and pressure, and density of liquid constituents at elevated temperature and pressure.

Peters *et al* applied the Hoberock *et al* compositional model successfully to model volumetric behavior of diesel-based and mineral oil-based drilling fluids. In their study, they measured the density of the individual liquid components of each drilling fluid at temperatures varying from 78-350 ^{o}F and pressures varying from 0-15,000 psi. Using this data in conjunction with Hoberock *et al*'s compositional model, they were able to predict the density of the drilling fluids at the elevated temperature-pressure conditions.

Isambourg *et al* proposed a nine-parameter polynomial model to describe the volumetric behavior of the liquid phases in drilling fluids, which is applicable in the range of 14.5-20,000 psi and 60-400 ^{o}F. This model characterizes the volumetric behavior of the liquid phases in the drilling fluid with respect to temperature and pressure, and is applied in a similar compositional model to that proposed by Hoberock *et al*. The model also assumes that all volumetric changes in the drilling fluid is due to the liquid phase, and application of the model requires a very accurate measurement of the reference mud density at surface conditions.

Babu compared the accuracy of the two compositional models proposed by Sorelle *et al* and Kutasov respectively, and the empirical model proposed by Kutasov in predicting the mud weights for 12 different mud systems. The test samples consisted of 3 water-based muds (WBM), 5 oil-based mud (OBM) formulated using diesel oil and mineral oil. Babu found that the empirical model yielded more accurate estimates for the pressure-density-temperature behavior of a majority of the mud over the range of measured data more accurately than the compositional model. He also concluded that the empirical model has more practical application because unlike compositional models, it is not hindered by the need to know the contents of the drilling fluid in question.

Drilling fluids contain complex mixtures of additives, which can vary widely with the location of the well, and sometimes with different stages in the same well. This was especially apparent in the behavior of the drilling fluids prepared with diesel oil No. 2. Different oils available under the category of diesel oil No. 2 that were used in the preparation of OBM's can exhibit different compressibility and thermal expansion characteristics, which were reflected in the pressure-density-temperature dependent behavior of the fluids prepared with them. The drilling fluids also consist of drill cuttings from the formation rock cuttings during drilling operations. The temperature and pressure of the annulus and wellbore might affected the thermal expansion and compressibility of the drill cuttings of the formation. This will lead to changes in circulating mud density and circulation pressure of drilling fluids in wellbore and annulus.

Research has also been reported on characterizing drilling fluid rheology at high temperature/pressure conditions. Rommetveit *et al* approached their analysis of shear stress/shear rate data at high temperature and pressure by multiplying shear stress by a factor that depends on pressure, temperature and shear rate. Coefficients of this multiplying factor are fitted to shear stress/shear rate data directly without extracting rheological parameters such as yield stress first. This eliminates the need to characterize the behavior of each rheological parameter relative to pressure and temperature changes. They obtain an empirical model in which the effects of variation in all rheological parameters that describe fluid flow behavior are lumped together.

Another approach to the analysis of temperature and pressure effects on drilling fluid rheology is to consider the effect of temperature and pressure changes on each rheological parameter that describes the behavior of the fluid. The two most common models considered for such an analysis are the Herschel-Bulkey/Power law model and the Casson model which is an acceptable description of oil based mud rheology. Of these two models, the Herschel-Bulkley model is the most robust, as it is a three parameter model as opposed to the Casson model which is a two parameter model. In the analysis performed by Alderman *et al* on shear stress/shear rate data, the Herschel-Bulkley/Power and Casson models were considered. The behavior of each rheological parameter in these models with respect to changes in temperature and pressure was investigated. They studied a range of fluids covering un-weighted and weighted bentonite water-based drilling fluids with and without deflocculant additives.

In order to estimate equivalent circulating density, it is important to take into account the effects of temperature and pressure on fluid rheology. Two methods are proposed to accomplish this by Rommetveit *et al*. They propose a stationary or static method and a dynamic method. In both methods, the contributions of hydrostatic and frictional pressure losses in high pressure/high temperature wells to the equivalent circulating density were considered. The variation in temperature vertically along the well bore is taken into account for both models, and drilling fluid properties are allowed to vary relative to temperature.

The dynamic method however, also takes into account transient changes in temperature as change in temperature over time. This effect is especially important in the case where circulation has been stopped for a significant amount of time. The drilling fluid temperature will begin to approach the temperature of the formation. Once circulation commences again as shown in Fig. 1, the lower part of the annulus will be cooled by cold fluid from the drill string and the upper part of the annulus will be warmed by hotter fluid coming from the bottom-hole. During this transient period, fluid density and rheological characteristics can change rapidly due to rapid changes in temperature. Research on this effect is still at a very early stage and will not be taken into account during this study.

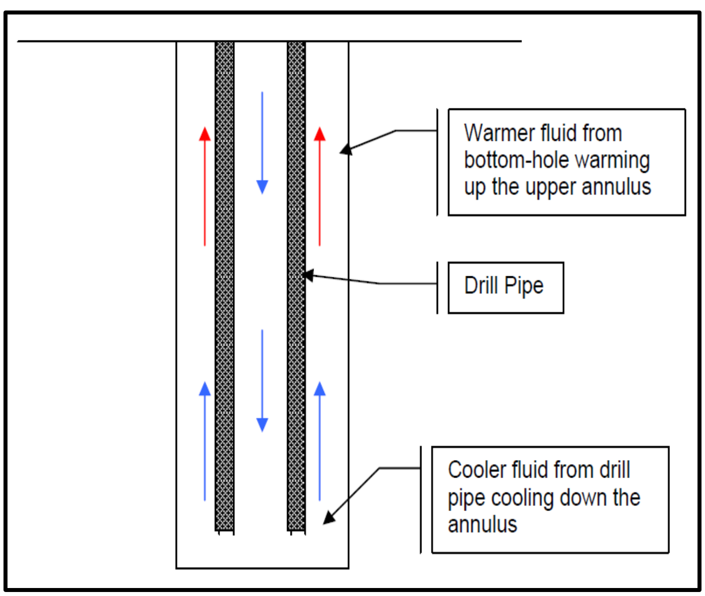


Figure 1: Schematic Diagram of Fluid in the Well bore at the Start of Circulation - Rommetveit *et al*, 1997.

Alderman *et al* performed rheological experiments on water based drilling fluids over a range of temperatures up to 260 ^{o}F and pressures up to 14,500 psi, using both weighted and unweighted drilling fluids. Rheograms were obtained for the water based drilling fluids, holding temperature constant and varying pressure, and vice versa. It was found that the Herschel-Bulkley model yielded the best fit to the experimental data. Other models that were investigated are the Bingham plastic model, and the Casson model which some authors argue is the best model for characterizing oil-based drilling fluid rheology.

For the Herschel-Bulkley model, it was found that the fluid viscosity at high shear rates increased with pressure to an extent, which increases with the fluid density, and decreases with temperature in a similar manner to pure water. Alderman *et al* found the yield stress to vary little with pressure-temperature conditions. The yield stress remained essentially constant with respect to temperature until a characteristic threshold temperature is attained. This threshold temperature was found to depend on mud composition. Once this threshold is reached, the yield stress increases exponentially with 1/T. Alderman *et al* also found that the power law exponent increased with temperature, and decreased with pressure. This makes them to conclude that the Casson model will become increasingly inaccurate at these two extremes, which is at high temperature and low pressure.

The estimation of ECD under high temperature conditions requires knowledge of the temperatures to which the drilling fluid will be subjected to down-hole. As the fluid is circulated in the wellbore, heat from the formation flows into the wellbore causing the wellbore fluid temperature to rise. This process is more pronounced in deep, hot wells where the temperature difference between the formation and the well-bore fluid is greater. The process is very dynamic at early times that are, at the commencement of circulation, with great changes in fluid temperature occurring over small intervals of time.

There are two major methods for estimating the down-hole temperature of drilling fluid. The first is the analytical method. This method assumes constant fluid properties. Ramey solved the equations governing heat transfer in a well bore for the case of hot-fluid injection for enhanced oil recovery. His solution permits the estimation of the fluid, tubing and casing temperature as a function of depth. He assumed that heat transfer in the well bore is steady state, while heat transfer in the formation is unsteady radial conduction.

Holmes and Swift solved the heat transfer equations analytically for the case of flow in the drill pipe and annulus. They assumed the heat transfer in the wellbore to be steady state. However, they used a steady-state approximation to the transient heat transfer in the formation. They justified this assumption by asserting that the heat transfer from the formation is negligible in comparison to the heat transfer between the drill pipe and annular sections due to the low thermal conductivity of the formation. The result obtained by Holmes and Swift have been used in different situations and predicted successfully the bottom-hole temperature using temperature logs. However, all the deductions and analytical expressions used to determine the drilling fluid temperature profile in the annular space have been used basically in vertical well. That is very common to find more applications of directional wells in present using same methodology. Acuna and Arnone obtained a mathematical expressions adjusted to any well trajectory.

The second method of estimating fluid temperature during circulation involves allowing the fluid properties such as heat capacity, viscosity, and density to vary with the temperature conditions. This method involves solving the governing heat transfer equations numerically using a finite difference scheme. Marshal et al created a model to estimate the transient and steady-state temperatures in a well bore during drilling, production and shut-in using a finite difference approach.

The experimental measurements presented by McMordie et al (1982) was realized to develop experimental data on the effect of temperature and pressure on the density of oil base and water base drilling fluids. The obtained data have been used to developing and testing different kind of algorithms to predict the effect of formation pressure and temperature on the fluid density. It were obtained as conclusions of the experiments that the density changes for a specific type of drilling fluids can be treated as function of temperature and pressure and independent of the initial fluid density. The density of an oil base drilling fluid will be greater than water base drilling fluid density at high pressure and temperature. The effects of temperature and pressure are not cancelled and in consequence there is a final influence on the drilling fluid density. If a change in fluid density under the effects of pressure and temperature is proven, then the effect on the calculation of static and dynamic bottom-hole pressure should be considered during Managed Pressure Drilling (MPD) is recommended to drill through a narrow operating window environment. Figure 2 shows that the experimental result of the change in density of drilling fluids to the temperature and pressure.

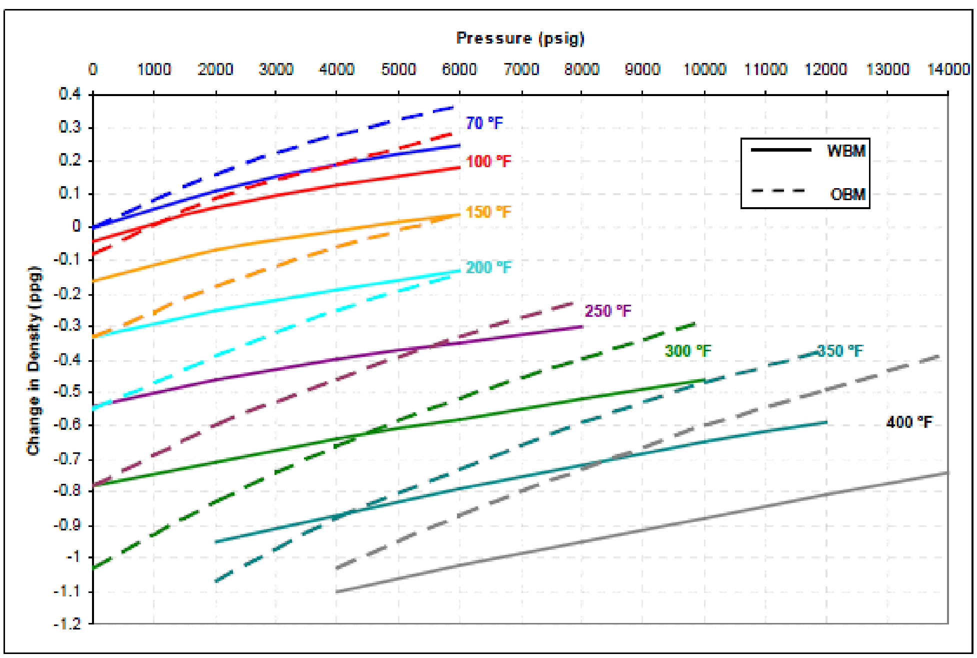


Figure 2: Experimental data of fluid density changes for water base and oil base mud - Mc Mordie et al, 1982)

The experiment conducted by Demirdal et al using a Mercury PVT cell and sampling system to determine the effect of pressure and temperature on density and compressibility. The experiments determined that the effects of temperature are more dominant compared to the effects of pressure, especially under low pressures, an increase in temperature may decrease the drilling fluid density.

Romero and Touboul created a numerical simulator for designing and evaluating down-hole circulating temperatures during drilling and cementing operations in deep-water wells. Zhongming and Novotny developed a finite difference model to predict the well bore and formation transient temperature behavior during drilling fluid circulation for wells with multiple temperature gradients and well bore deviations.

Arnold also solved the heat transfer equations analytically for both the hot-fluid injection case and the fluid circulation case. However, in circulation case, he did not assume steady state heat transfer in the formation. He represented the transient nature of heat flow from the formation with a dimensionless time function that is independent of depth. Kabir et al also solved a similar set of equations, but for the case of flow down the annulus and up the drill pipe. They also assumed transient heat flow in the formation, and evaluated a number of dimensionless time functions.

Annis investigated the changes in rheological property with time and temperature up to 3000F by a concentric-cylinder, rotational viscometer of the Fann type. His experiments covered the effects of temperature and aging on shear rate – shear stress, gel strength and viscosity. The study concluded that high temperature causes flocculation of bentonite clays, resulting in high yield points, high viscosities at low shear rates, high gel strengths and a permanent thickening of the mud. He added that proper treatment of bentonite mud with NaOH and lignosulphate reduces the effect of dispersion and flocculation at high temperature.

Mohammed Shahjahan Ali, later wrote a thesis from a laboratory investigation on the effect of high temperature (4900F) and aging time of 30days on water-base mud properties using the HTHP viscometer, baroid roller oven(dynamic aging) and distilled water as the continuous phase. The result shows a decrease in viscosity, yield point and gel strength with the increase in temperature for all values of aging time. He concluded that shear stress for a particular temperature increases with increase in shear rate, but shear stress at a given shear rate decreases with increase in temperature. Viscosity, yield point and gel strength at a given temperature increase with aging time and aging effects are diminishing with the increase in aging time. Shear stress at a given shear rate increases with aging time and aging effects decrease with the increase in aging time.

S.Salimi *et al* conducted a research on the rheological behavior of polymer-extended water-based drilling mud at high temperatures and high pressures simulating their true working conditions in a deep oil well. The performance of these polymers as a rheology modifier in drilling systems was then investigated using a Fann 50C commercial viscometer. By measuring shear stress vs. shear rate (i.e., the flow curve) at pressures up to 500 psi and temperatures up to 300°F , it was found that temperature had a detrimental effect on the rheological properties of the test fluids while the effect of pressure on these properties was realized to be less significant (specially at pressure above 300 psi).

Osman and Aggour carried out an experiment to determine drilling mud density change with pressure and temperature using a newly developed Artificial Neural Networks (ANN) model. Available experimental measurements of water-base and oil-base drilling fluids at pressures ranging from 0 to 1400 psi and temperatures up to 400 °F were used to develop and test the ANN model. With the knowledge of the drilling mud type (water-base, or oil-base) and its density at standard conditions (0 psi and 70°F) the developed model provides predictions of the density at any temperature and pressure (within the ranges studied) with an average absolute percent error of 0.367, a root mean squared error of 0.0056 and a correlation coefficient of 0.9998.

Exner carried out an investigation on the effects of temperature on the viscosity of some Gulf coast drilling mud. The purpose of this investigation was to determine the relative changes in the apparent viscosity of mud with changes in temperature and to discover other physical effects due to heat. Exner states: “Very little information has been published regarding the effects of temperature on the viscosity of drilling mud”. He quoted Maustl who stated that "The viscosity of most mud is decreased on heating, but the interesting thing is that the degree of flocculation is also increased on heating. There will be a greater tendency to seal off formations at high temperatures than at low temperatures." With regard to the effect of temperature on viscosity and yield point, Exner states: "The variation of yield point and viscosity of mud with temperature is not very clearly brought out by the data available. Both appear to decrease slightly with increasing temperature up to 2000F." The experimental results presented in this paper further emphasize this point. Two types of viscometers are available for measuring the apparent viscosities of drilling mud: the efflux tube type as used by Herrick3 and Marsh, and the torsion type such as the McMichael or the Stormer viscometers.

Shokoya *et al* conducted a study on the rheology and corrosives of water-base drilling fluid under simulated down-hole conditions. The rheological property and corrosion behavior relationship of mild steel type 1018 in a typical drilling fluid used in deep drilling and hot wells was studied. The tests were conducted under conditions that simulate flow, temperature, and pressure encountered during drilling operations. Physical properties that were considered are: shear stress-shear rate relationship, effective and plastic viscosities, yield strength and gel strength. The properties were determined under high temperature and pressure by using a flow loop, the Baroid roller oven and the FANN-70 viscometer. The corrosion measurements were carried out by weight loss and electrochemical techniques. The effective and plastic viscosities of the drilling fluid decrease with increase in temperature and increase in time of exposure to down-hole conditions. The corrosion rate increase with the decrease in pH of the fluid. The corrosion rates are lower at the mildly alkaline pH and higher in the mildly acidic pH range. The drilling fluid generally attacks the grain boundaries of the steel samples. Diffusion was found to be the rate limiting step for the corrosion reactions.

Pavel published an article titled “High-Pressure/High-Temperature Operations: Aqueous drilling fluid contends with HP/HT wells”. He presented a new water-based drilling fluid developed specifically to contend with the unique challenges of onshore ultra-deep HP/HT wells in sensitive ecosystems. He stated that HT gelation is an overriding problem with water-based mud even in routine applications but is magnified considerably in deep HP/HT wells. Gelation is caused when clay or bentonite in the fluid flocculates. Aqueous systems require very tight control of the solids content along with selecting thermal-stable products for treatment. HT gelation and degradation of product and mud properties increase HP/HT fluid loss. With drilling fluid densities approaching 17 lb/gal, barite sag can impact the entire operation. Very high rheology was observed, with some samples appearing almost dry after aging.

Wang *et al* performed a detailed hydraulic simulation of MPD operation in narrow pressure windows. The rheology models of drilling fluid were compared and determined based on the drilling fluid used in MPD operation and Robertson-Stiff model was employed in the study. The effects of temperature and pressure on ESD and shear stress of drilling fluids were studied based on the experiments and theoretical analysis. Some important parameters used such as tool joint parameters, pump feed efficiency, hole geometry, drilling string configuration for hydraulic simulation of MPD applications. The simulation results were compared with one-site real time PWD data. This paper is mainly about the hydraulic simulations with determination of suitable rheological model and properties to be used as parameters in the simulation.

J. C. Cunha presented the importance of drilling fluids rheological and volumetric characterization to plan and optimize Managed Pressure Drilling operations. In this research, the rheological properties have been determined using rheological modeling for n-paraffin synthetic based mud for 8.4 ppg in term of plastic viscosity and yield point. The change in density for this type of drilling fluid has been studied for empirical model. For simulation model, the offshore and onshore scenario data have been used to simulate the application of drilling fluid density for both wells with different properties and the application of applied backpressures. The uses of lighter drilling fluid in offshore well with the application of applied backpressures has been determined and compared with the onshore well simulation.

THEORY

2.2 FUNDAMENTAL CONCEPTS OF EQUIVALENT STATIC AND CIRCULATING DENSITY

As today's challenges, the oil companies are looking to search for oil and gas in more challenging areas such as deep and ultra deep offshore locations. These wells have high temperature/pressure profile and un-drillable using conventional drilling method. Precise and best practices in well control and management are needed to drill the well. In order to maintain proper well control to prevent lost circulation, and accurately analyze fracture gradient data, it is importance to accurately predict the density of the drilling fluids, under pressure and temperature conditions. Drilling fluids become compressed under high pressure, and expanded with temperature due to the thermal expansion and compressibility effect. Hence, the density of drilling fluids in the bottom-hole condition is different from the drilling fluid density at the surface, which is usually measured during drilling operations.

2.2.1 Equivalent Static Density (ESD)

The equivalent static density of a drilling fluid is an expression of the hydrostatic pressure exerted by a static column of fluid. The equivalent static density of a column of drilling fluid takes into account the effect of the pressure and temperature conditions of the well. Hydrostatic pressure is expressed in field units as follows.

$$P=0.052\rho h \quad \text{..........} \quad (2.2)$$

This simple equation assumed the fluid to be incompressible. If the temperature and pressure in the mud is low, the use of constant surface mud density will express the approximation of the bottom-hole density of the fluid. As the fluid density affected by formation pressure and temperature, the hydrostatic calculation must be corrected using variation fluid density in order to get the real value of static bottom-hole pressure. Excluding these factors in the estimation of bottom-hole pressure may result in error by hundreds of psi of pressures. The effects of temperature and pressure on the density of various base liquids that can be used in drilling fluids are determined. As the fluid density affected by pressure and temperature, the hydrostatic calculation must be corrected using various fluid density in order to get correct estimation of bottom-hole pressures. As the height of fluid column increases, the hydrostatic pressures will increase with the density of the fluids to be constant.

2.2.2 Equivalent Circulating Density (ECD)

The equivalent circulating density of a drilling fluid can be defined as the sum of the hydrostatic head of the fluid column, and the pressure loss in the annulus due to fluid flow. It can be expressed in the equation as below.

$$\rho_{ecd} = \frac{1}{0.052h}\left(\Delta P_{hydrostatic} + \Delta P_{friction}\right) \quad \text{……………} \quad (2.3)$$

The hydrostatic pressure of the drilling fluid is affected by the temperature and pressure in the well-bore, and the depth of the well-bore. The frictional pressure loss term in the equation however is affected by the well-bore and drill string geometry, fluid rheology, and the pump rate or fluid flow rate. Formation temperature cause thermal expansion of the drilling fluid caused lower in ECD and ESD, while formation pressures result in compression and increase in ECD and ESD. The effect of pressure and temperature are not cancelled and the determination of the final effect is determinant at the moment Managed Pressure Drilling (MPD) operation will be planned and applied.

2.3 FLUID RHEOLOGY

Rheology is the study of the deformation and flow of matter, in this case drilling fluids with the flow characteristics is highly depending on it. Rheological models seek to characterize the flow behavior by developing relationships between applied shear stress, and the shear rate of the specific fluid. Most drilling fluids are dispersions or emulsions with a complex rheology. The rheology or flow behavior of most common drilling fluids is non-Newtonian with complex relationship between shear stress and shear rate. Making certain measurements on a fluid leads to describing the fluid’s flow behavior under a variety of temperatures, pressures, and shear rates. Based on this relationship, fluids in general can be classified as Newtonian, non-Newtonian, and visco-elastic fluids.

2.3.1 Shear Stress and Shear Rate

In a flowing fluid, a force existing in the fluid that opposes the flow known as shear stress. The shear stress is a force per unit area between two layers of fluids sliding by each other. The shear is occurring between two layers of fluid than between the fluid's outer layer and the pipe wall. Accordingly, the force per unit area required to sustain a constant rate of fluid movement, the shear stress, is defined as

$$\tau = F/A \qquad (2.4)$$

The pressure loss in a circulating system, the pump pressure, and the flow rate of a circulating system, the pump rate, can be related to the shear stress and the shear rate, respectively. The shear rate of a flowing fluid associated with average velocity of the fluid in the channel. The fluid flowing in small geometries (inside tubing) has a higher shear rate than a fluid flowing in large geometries such as casing or riser annuli. For a fluid, the relationship between the shear rate and the shear stress determines how that fluid flows and rheological models have been determined from this relationship.

Newtonian Fluids- Newtonian fluids are fluids in which the ratio between applied shear stress, and the rate of shear is constant with respect to time. In other words, the plot of shear stress versus shear rate of a Newtonian fluid yields straight line that passes through origin of the plot coordinates. Examples of Newtonian fluids are water, light hydrocarbons, and all gases. The relationship characterizing Newtonian fluids is expressed mathematically as follows:

$$\tau = \mu\dot{\gamma} \qquad (2.5)$$

Non-Newtonian fluids- Non-Newtonian fluids are fluids whose viscosity varies with time and shear history. This class of fluids can be further subdivided into time-dependent and time-independent fluids. Time-dependent fluids are fluids, in which the viscosity varies with time at a constant shear rate, while time-independent fluids are fluids whose viscosity is constant over time at a constant shear rate. Most common drilling fluids are non-Newtonian fluids. Figure 3 shows the relationship between shear rate and shear stress for different type of fluids using rheological models available.

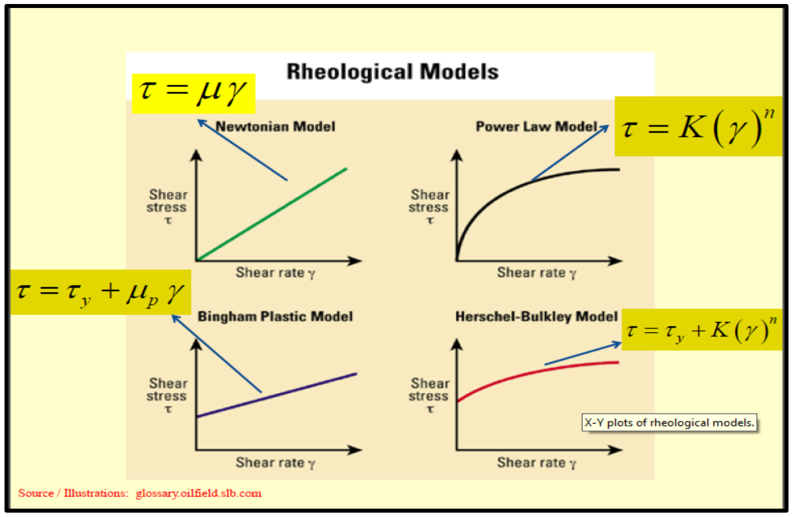


Figure 3: Shear rate and shear stress relationship for different rheological models - *Source: glossary/oilfield.slb.com*)

Visco-elastic Fluids- These are fluids which exhibit both viscous and elastic behavior. When subjected to stress, they deform and flow like fluids, but once the stress is removed, they regain some of their original state like solids. Examples of visco-elastic fluids include flour dough, and polymer melts. The following are the rheological models that characterize the various types of non-Newtonian fluids:

1) Bingham Plastic Model
2) Power Law model
3) Herschel-Bulkley Model
4) Casson model
5) Ellis model
6) Carreau model

In order to characterize the flow behavior of the drilling fluid under high temperature-high pressure conditions, the Bingham plastic model with temperature/pressure dependent model parameters will be applied. The Bingham Plastic fluid is non-Newtonian fluid with the behavior similar to the Newtonian fluid by applying certain amount of stress in order to enable the fluid to flow and the stress called yield stress. The relationship between shear rate and shear stress is very important to determine the flow behavior of fluid using various rheological models. This model was chosen because it is the most commonly used rheological model on the oil field and models the behavior of a wide variety of fluids.

2.4 HEAT TRANSFER

As fluid flows in the wellbore, it absorbs heat from the formation, causing a rise in the temperature. There are heat transfer between formation and annulus and between drill pipe and annulus. The formation temperature and bottom-hole pressure will increase as the well depth increase and this increment can lead to changes in the fluid volumetric, rheological properties and pressure drop across wellbore. This effect is more obvious in high temperature/pressure wells and fluids with temperature sensitive rheological properties. The drilling fluid density decreases as temperature increase and vice versa with pressure. The precise evaluations and analysis of the effect of temperature and pressure on wellbore hydraulics is needed for narrow pressure window wells with taking into consideration of these effects.

The temperature profile within wellbore for annular and drill string can be simulated with geothermal gradient of formation vary with depth and time. The fluid temperature at certain depth is not constant due to the thermal phenomena present during the circulation of drilling fluids. There is heat transfer from the formation to the wellbore due to the difference between geothermal and the drilling fluid temperatures. It can be analyzed in two parts which are the heat transfer between fluid inside the drill string and the fluid inside annular space and the heat transfer between the annular space and formation. While drilling bit is cutting the rock formation, there is a small heat generation but its effect is insignificant compared to the total heat generation in the total system. The formation temperature in one point far from the drilled hole is constant and then considers the formation acts as heat source. There are a few assumptions made for heat transfer analysis in order to generate the temperature profile for wellbore. The following are the assumptions made for the heat transfer in order to analysis the heat generation due to the geothermal gradient and circulating temperature of the drilling fluid inside the wellbore.

1) The flow of drilling fluid is one-dimensional steady flow.
2) Wellbore heat transfer is radial steady-state, the heat transfer of formation around wellbore is non-steady state.
3) Heat generation by viscous dissipation in fluid is negligible.

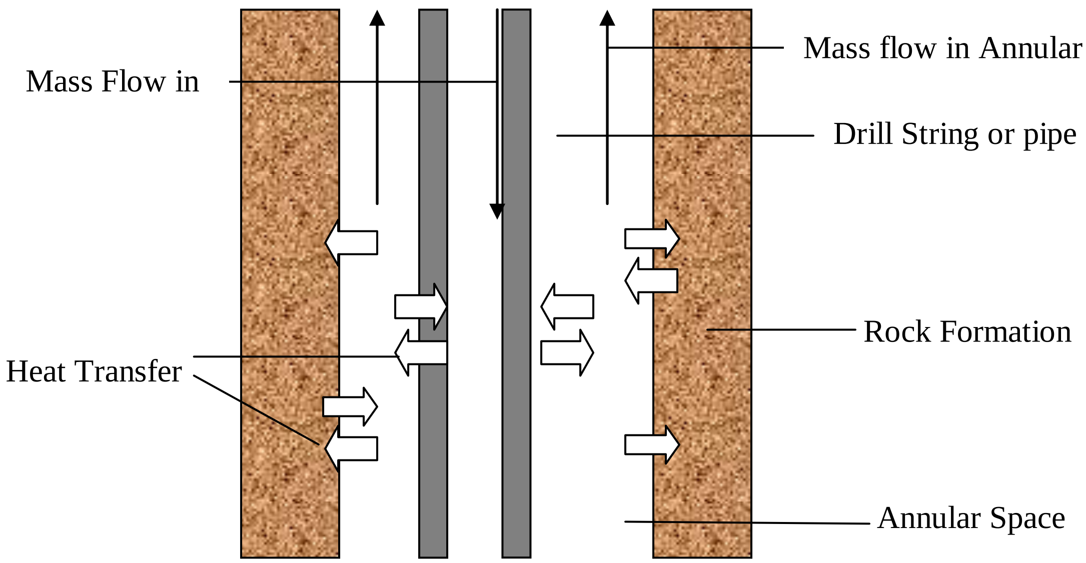


Figure 4: Schematic of Heat Balance for Fluid Circulating in a Wellbore

Figure 4 shows a schematic of drilling fluid circulating in the wellbore and the associated heat transfer process. The figure shows heat flow from the formation into the annular section through convection. The rate of heat flow by convection into the annulus is greater than the rate of heat conduction in the formation. This is due to the relatively low heat conductivity of the formation. This is very important when modeling the heat transfer process in the wellbore. The fluid within the drill pipe receives heat from the annulus via convection on the pipe surface on the inside and outside of the drill pipe, and conduction through the drill pipe itself. There is heat flow in and out of the differential elements within the drill pipe and annulus due to the bulk flow of fluid.

2.5 MANAGED PRESSURE DRILLING (MPD)

Managed Pressure Drilling as a discipline or drilling technique is the result of high costs of nonproductive time (NPT) caused by the close proximity between pore pressure and fracture pressure (Arnone, 2009). MPD is a general description of methods for well bore pressure management. It includes a number of ideas that describe techniques and equipments involved to limit kick wells, lost circulation, and differential pressure sticking in order to reduce the additional casing string required to reach total depth or target depth. It is intended to avoid continuous influx of formation fluids to surface. It applied equipments and methods to control the wellbore pressure. It also reduces ECD problems when drilling extended reach wells and narrow operating window wells. The well bore pressure management has application in the drilling industry and provides solution to problems as describe Arnone *et al*, 2009.

1) Extending casing points to limit total number of casing strings and hole size reduction
2) Reduced the NPT associated with differentially stuck pipe
3) Avoiding or limiting the lost circulation
4) Drilling with total lost returns
5) Increasing the penetration rate
6) Deepwater drilling with lost circulation and water flows

The International Association of Drilling Contractors (IADC) has recently made the following formal definition of MPD: "MPD is an adaptive drilling process used to precisely control the annular pressure profile throughout wellbore. The objectives are to ascertain the down-hole pressure environment limits and to manage the annular hydraulic pressure profile accordingly. This may include the control of back pressure by using a closed and pressurized mud returns system, down-hole annular pump, rotating control device (RCD) and other mechanical devices. It is intended to avoid continuous influx of formation fluids to surface. Any influx incidental to the operation will be safely contained using an appropriate process.

MPD helps manage the problems of massive losses associated with drilling fractured and karstic carbonate reservoirs. It also reduces ECD problems when drilling extended reach wells and wells with narrow margins between formation breakdown and well kicks. In long horizontal sections, reducing ECD helps mitigate the impact of drilling fluid induced impairment that amplified by high overbalance. The definition of MPD is that it proposes that the drilling plan is not only changeable but will change as the conditions in the well bore change. The basic techniques covered under MPD as described by Arnone *et al*, 2009 are:

1) Constant Bottom-hole Pressure (CBHP) – Narrow Pore and fracture pressure gradient window present a drilling hazard. It describe actions taken to correct or reduce the effect of circulating friction loss or equivalent circulating density (ECD) in an effort to stay within the limits imposed by the pore pressure and fracture pressure. When fluid circulation in ceased, the hydrostatic pressure lies below the formation pore pressure. A kick-loss situation ensues; nonproductive time (NPT), lost fluid cost and HSE risk escalate. This variation is applicable to avoid changes in Equivalent Circulating Density (ECD) by applying appropriate levels of surface backpressure in order to maintain the constant bottom-hole pressure during drilling operation.
2) Pressurized Mud –cap drilling – it refers to drilling without returns to the surface and with a full annular fluid column maintained above a formation that is taking injected fluid and drill cuttings. The annular fluid column requires an impressed and observable surface pressure to balance the down-hole pressure. It is a technique to safely drill with total lost returns.
3) Dual Gradient Drilling – The wellbore is drilled with two different annulus fluid gradients in place. Techniques to achieve a dual gradient include injecting a lower density fluid through a parasite string, through a concentric casing or actively pumping fluid returns from the seafloor through lines external to a seawater filled riser. In all cases the objective is to allow adjustment of the bottom-hole pressure within a predetermined range without changing the base weight of the drilling fluid.

4) Return Flow Control Drilling – When using an open to the atmosphere fluid return system when drilling with hazardous drilling fluids or in formations expected to have high concentrations of toxic gases that raises health, safety and environmental concerns. The use of close system at surface and the right procedures reduces the risk personnel, equipment and the environment from drilling and formation fluids and well control incidents

The MPD for Constant Bottom-hole Pressure (CBHP) enables "Walking the Line" between the pore and fracture pressure gradient while drilling the formation with expected gas kicks or losses. The objective is to drill using a combination of such a mud weight and especial procedures, to make the bottom-hole pressure constant under dynamic and static conditions considering the effect of pressure and temperature on the variations of drilling fluid density. The change in Equivalent Mud weight is instantaneous by adjusting the circulation pump rate or the back pressure on the MPD choke in order to control the pressure profile in the wellbore. Many drilling problems rise from the conventional drilling practices. The pressure fluctuation can be compensated at surface using specialized equipment in order to maintain pressure constant.

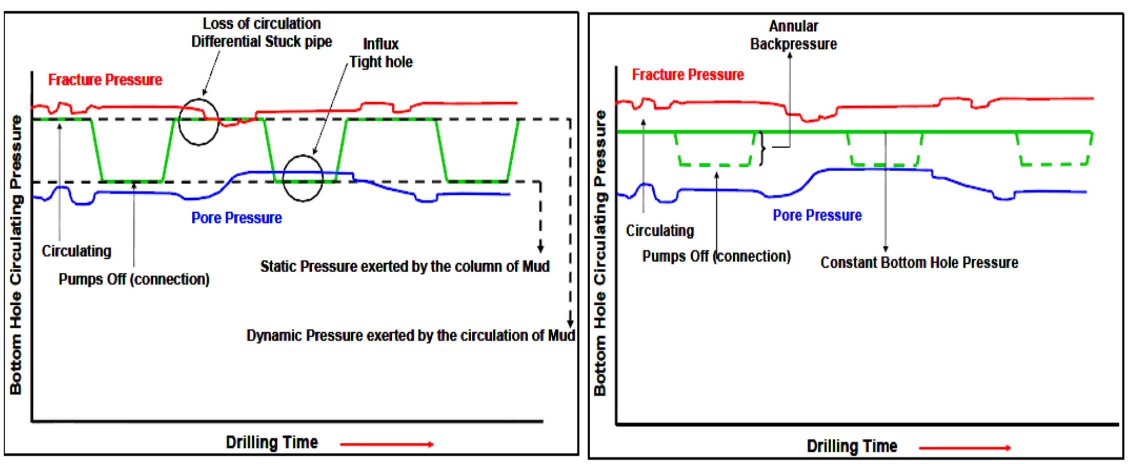


Figure 5: Static and dynamic pressure for MPD (right) and conventional drilling process (left) – Arnone *et al*, 2009

The annulus backpressure is controlled at surface, using a dedicated choke which means that changes in bottom-hole pressure normally occurring when operating mud pumps to circulate and drill ahead do not occur. The bottom-hole pressure is constant and can be more easily maintained within the bounds of a narrow operating window, whether the mud column is static or dynamic conditions. In MPD, the ability to accurate "walk the line" between operating window means the hole section can be drilled deeper before drilling mud density is changed and casing must be set. It provides sensitivity to manage the uncertainty of the estimated pore pressure, as often occurs with high pressure/high temperature (HPHT) deep wells drilling and complex geological environments.

The flow behavior in the wellbore during the application of MPD should be simulated in order to define the circulating parameters that will be used during the drilling process. These parameters will maintain the dynamic down-hole pressure within the defined operating window which is bounded by the pore pressure and the formation fracture pressure. Both limits are usually evaluated as the well drilling progresses by adjusting the pressure on surface manipulating the MPD choke. In order to maintain constant the bottom hole pressure, during the complete drilling process is necessary to calculate the frictional pressure loss in the annular considering the effect of temperature and pressure on the fluid density. The process to keep during static conditions the same pressure exerted during dynamic conditions manipulating the drilling fluid flow rate and the MPD choke is normally called Step-up and Step-down procedure. The basic of MPD methodology is to accurately determine the change in bottom-hole pressure caused by dynamic effects and compensate with an equal change in annular wellhead pressure during static conditions. The effect of pressure and temperature on the fluid density is considered in the hydraulic evaluation and applied even for dynamic than static conditions of drilling fluid.

Before perform a pipe connection, the driller will decrease the flow rate progressively in a determined number of steps (step-down) and the same time the MPD choke operator will compensate the loss in annular pressure closing the MPD choke progressively in same number of steps (Step-up).The process diagram for the additional MPD surface equipment to be supplied for a standard MPD operation that is basically, a rotating control device (RCD), an MPD Choke Manifold, flow meter as early detection system for gas kicks are expected as shown in figure below. An excellent communication between the MPD choke and rig pumps operators in order to obtain a resultant constant bottom-hole pressure during Step-Down/ Step-Up procedures. Figure 6 shows the process diagram of additional surface equipments for typical MPD operation and the arrangement of the equipments include Rotating Control Device (RCD) and MPD choke manifold.

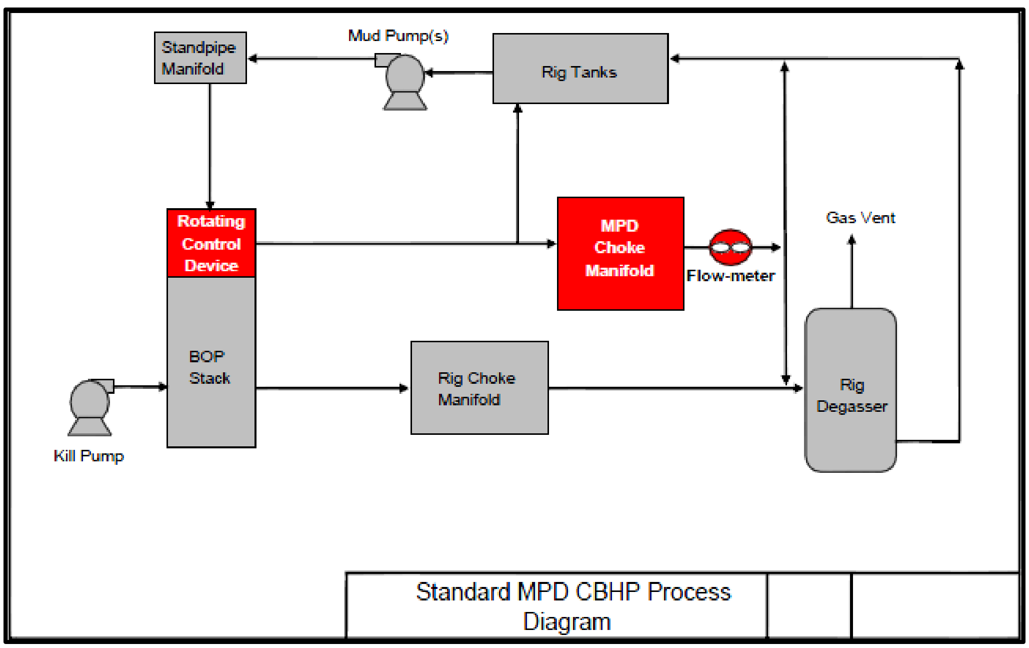
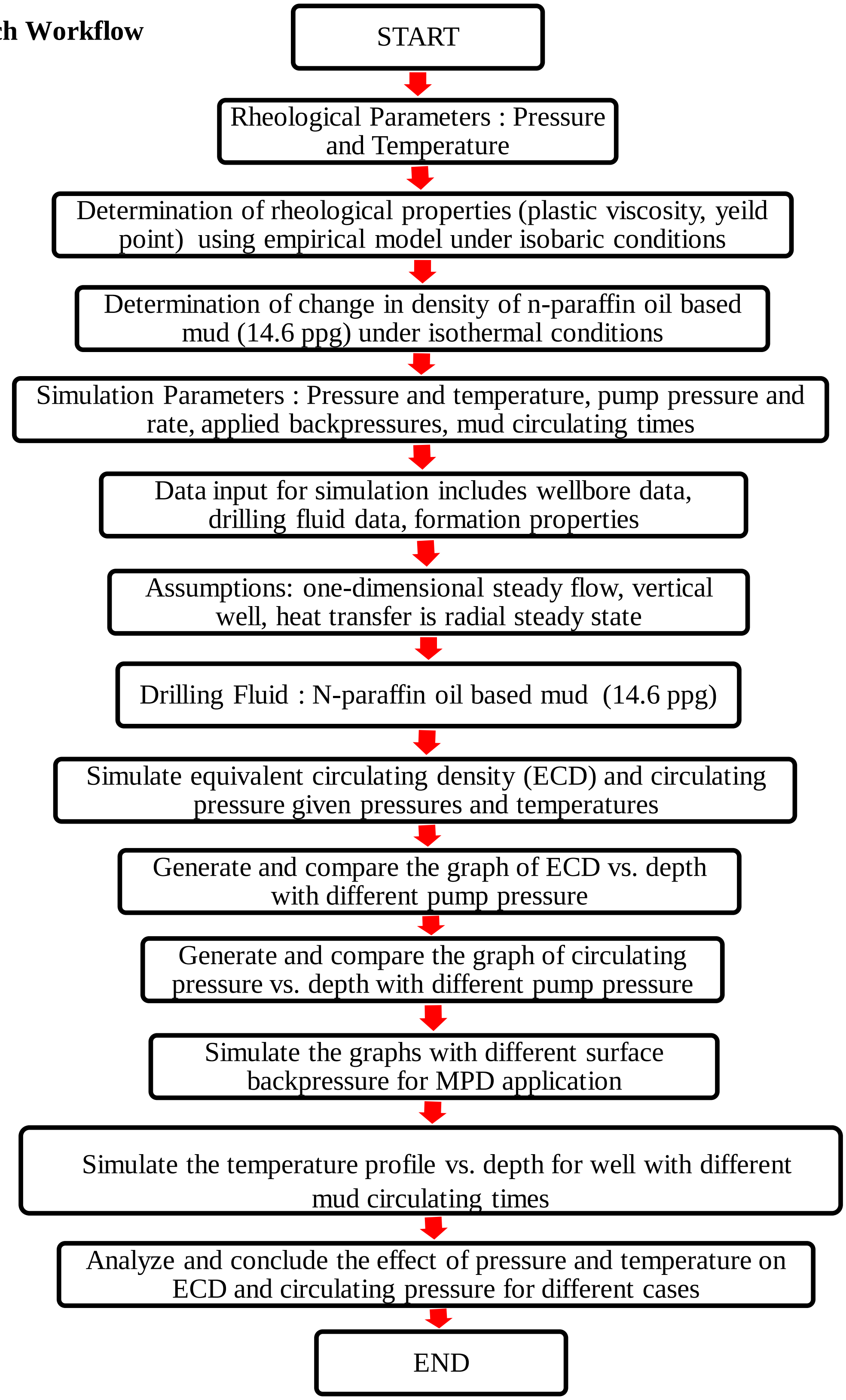


Figure 6: Process diagram of additional surface equipments for MPD operation – Arnone *et al*, 2009

CHAPTER 3

METHODOLOGY

3.1 Research Workflow



-N-paraffin oil/synthetic based drilling fluid with mud weight 14.6 ppg is used to determine the effect of pressure and temperature on rheological properties (plastic viscosity and yield point) and in term of equivalent circulating density, ECD and circulating pressure via simulation and empirical model. The first part of the study is focused on determining the rheological model of the fluid under various pressures and temperatures range and determining rheological properties using empirical model that relates the rheological of fluids as functions of pressure and temperature.

3.2 Rheological Modeling

The flow behavior of drilling fluids was analyzed under pressure and temperature variations with the following non-linear and linear regression techniques for Bingham Plastic model developed by B. Demirdal (2006). This empirical model derived from the experiments done using HPHT rotational viscometer and Mercury Free PVT cell for n-paraffin oil based mud. These analyses done in order to determine the rheological properties such as plastic viscosity yield stress and change in density of drilling fluids with the pressure and temperatures variations.

The equivalent circulating density can be modeled and simulated with the given pressure and temperature in the wellbore and annulus using mud gradient operating window. The annular pressure profile can be determined from the calculation of the pressure loss in the annular given the flow regimes, Reynolds's number, friction factor, wellbore geometry, and velocity of the fluids using several equations to estimate wellbore pressure. The outcomes of the simulation are in term of ECD for different cases and parameters, circulating pressures along the wellbore, change in density of drilling fluid, and rheological properties determination using empirical model.

Temperature and Pressure Dependent Plastic Viscosity

The relation between plastic viscosity and temperature in isobaric conditions is shown in Figure 7. The plastic viscosity decreases with increasing temperature with different pressure conditions. This relation can be expressed in the equation as follows,

$$(\mu_p)_{P=constant} = A\,T^{-B} \quad \text{.......} \quad (3.1)$$

The coefficients A and B are exponential functions of pressure and determined using regression analysis. The plastic viscosity of the drilling fluid can be expressed as function of pressure and temperature as shown follows,

$$(\mu_P)_{T,\,P} = (2750 \exp^{1.9*10\text{-}4\,P})*\,T^{-(1.04 \exp(2*10\text{-}5)\,P)} \quad \text{.......} \quad (3.2)$$

The plastic viscosity is calculated at various pressures and temperature under isobaric conditions and the value of μ_P was determined by using this method. The value of plastic viscosity is then tabulated as shown in Table 1 with the variation of temperature under constant pressure using calculated value of coefficients.

Temperature and Pressure Dependent Yield Point

Regression analysis is done to relate the yield point with the pressure and temperature variations. The relation of yield point with the parameters under constant pressure condition can be seen on Figure 8. It shows that yield point decreases with increasing of temperature at the specific pressure. But in higher temperature, yield point tends to increases due to the gelation effect and change in yield point is very minimal. The relation of yield stress and temperature under isobaric conditions is shown as follows,

$$(\tau_Y)_{P = constant} = C\,T^{-D} \quad \text{.......} \quad (3.3)$$

The coefficients C and D are dependent on pressure conditions. The polynomial relations were used to relate the coefficients to pressure and temperature conditions. The yield point relation in term of pressure and pressure can be expressed as follows,

$$C = -1.49*10^{-13}\,P^5 + 2.75*10^{-9}\,P^4 - 1.315*10^{-5}\,P^3 + 2.075*10^{-2}\,P^2 - 6.511P + 797 \text{...} \quad (3.4)$$

$$D = (-\,2.234*10^{-8}\,P^2 + 3.660*10^{-4}\,P + 0.882) \quad \text{.......} \quad (3.5)$$

By substituting these coefficients in term of pressure as shown in equation (3.4) and (3.5) into equation (3.3), the relation of yield point to the pressure and temperature variations is developed. The value of yield point is calculated and tabulated as shown in Table 2 with variation of temperature under constant pressure condition using calculated coefficients for the equation.

Temperature and Pressure Dependent Density

The density of drilling fluids is affected to the pressure and temperature variations especially for oil/synthetic based mud. The density changed with respect to the pressure and temperature should be analyzed in order to determine the ECD, bottom-hole circulating pressure and pressure losses. The effect of pressure on density of drilling fluid under isothermal condition for n-paraffin synthetic based mud is shown in Figure 9 with the change in density over pressure range. The density of fluid is increasing as pressure increases. The fluid is used as slightly compressible fluid and the density relation can be expressed as follows,

$$(\rho)_{T\,=\,constant} = \rho_i \exp\,(Y * P) \qquad (3.6)$$

The relation of ρ_i and temperature can be expressed as polynomial using regression analysis as shown as follows,

$$\rho_i\,(T) = (-5.36*10^{-6})* T^2 + (-1.27*10^{-3})* T + 14.76 \qquad (3.7)$$

The relation between Y coefficient and temperature is determined as polynomial as result of regression analysis and can be expressed as follows,

$$Y\,(T) = (9.45*10^{-11})*T^2 + (-1.53*10^{-8})*T + 4.19*10^{-6} \qquad (3.8)$$

By substituting these equations (3.7) and (3.8) into equation (3.6), the empirical relation for density of n-paraffin synthetic based drilling fluid to the pressure and temperature variations is generated. The value of change in density is calculated and tabulated as shown in Table 3 under pressure variations under constant temperature condition using calculated coefficients. The rheological properties of n-paraffin oil based mud with 14.6

ppg in term of plastic viscosity, yield point and change in density is calculated and analyzed using graph under pressure and temperature variations. The value of rheological properties is then used in the simulation in order to simulate the ECD and circulating pressure for this type of drilling fluid using same rheological model. The plastic viscosity and yield point value that being used in the simulation are 30.3 cp and 8 lb/100ft respectively by using 500 psi as pressure reference and 80 °F as temperature reference for these values.

3.3 Simulation Model

Several assumptions have been made in order to develop simulation model to determine the ECD, circulating pressure and temperature profile along the wellbore. These assumptions are as follows,

1) Effect of drilling cuttings is neglected to pressure losses and change in density parameters in the simulation.
2) Wellbore heat transfer is radial steady state, heat transfer between wellbore and formation in non-steady state.
3) Drill string is concentrically placed in the wellbore and wellbore diameter is circular and constant.
4) One-dimensional steady state flow in annulus and drill pipe.
5) Vertical well, no trajectory and horizontal well without consideration of the effect of well trajectory and deviation.

The simulation is done using Landmark® Wellplan software in order to simulate the ECD, circulating pressure along wellbore and temperature profile using rheological data from the empirical model using regression analysis technique. The pressure and temperature parameters are simulated using this software by introduced various pump rates, mud circulating times, and applied backpressures as the variables in the simulation in order to simulate the MPD application. These parameters are simulated to get the result in term of ECD, circulating pressure and temperature profile along the wellbore.

The hydraulic simulation for specific type of drilling fluids under temperature and pressure condition in the wellbore can be done using Hydraulic Mode in one of the Landmark® Wellplan modes. The hydraulic model gives the result in term of ECD, circulating pressure, pressure losses, annular velocity, rate of penetration (ROP), hole cleaning and optimization of hydraulic design respect to the design and type of drilling fluid used. It enables the details analysis on the hydraulic model using mud operating window in term of equivalent mud weight of pore pressure and fracture pressure. The wellbore condition can be simulated in pressure and temperature variations in order to analyze the ECD and circulating pressure for specific type of drilling fluid. Figure 10 shows that the Landmark® Wellplan Software using Hydraulic Mode as active mode for analysis of ECD and circulating pressure profile.

3.3.1 Simulation Data Input

The wellbore data, drilling fluid properties and wellbore configuration used in the simulation is shown in Table 4. The simulation data is compared with the actual data in order to make sure the data are reliable and compatible with the real application on MPD. The data is used in the simulation with several data is assumed in order to simulate the results with assumption of drill string equipments data, bottom-hole assembly, and casing/riser configuration.

Table 4: Wellbore data, drilling fluid properties and wellbore configuration for simulated well

Well data	
Total Vertical Depth (TVD), ft	28000
Drill Stem, OD, in.	5
Bit size, in.	8.5
Pump rate, gpm	0-700
Circulation time, hours	0-10
Inlet mud temperature, °F	80
Geothermal Gradient, °F/100ft	1.29
Drilling fluid data	
Plastic Viscosity, cp	30.3
Yield Point, lb/100ft	8.0000
Density, lb/gal	14.6

Thermal Conductivity, Btu/lb-°F	30.0
Specific heat, Btu/lb-°F	0.5090
Oil Fraction	0.750
Water Fraction	0.250
Reference Pressure, psi	500
Reference Temperature, °F	80
Wellbore Configuration	
Casing Setting Depth, ft	24140
Casing Diameter, in.	11.75
Riser ID, in.	18.75
Riser Length, ft	8100

The wellbore configuration and down-hole drilling equipments are simulated using Landmark® Wellplan software in well schematic diagram as shown in Figure 11 and Figure 12 respectively. The bottom-hole assembly (BHA) diagram for the well also simulated using same software with details of drill string equipments used to drill the formation as shown in Figure 13. The data input for simulation are inserted in the software and simulated with different variables such as pump rates, backpressures, mud circulating times and pump pressure. With these parameters, the result in ECD and circulating temperature is obtained from the simulation. Figure 14 shows the data input for pump rates with application of backpressure and mud circulating time in the Landmark® software window.

CHAPTER 4

RESULTS AND DISCUSSIONS

For this project, the oil/synthetic-based mud is being modeled for their rheological properties by using empirical model. The drilling fluid properties in term of plastic viscosity, yield point and density will be modeled using empirical method by B. Demirdal (2006) in order to develop the empirical data with temperature and pressure variations. By using Landmark software program, it simulated or demonstrated the effect of pressure and temperature in wellbore condition in term of ECD and circulating pressure with application of MPD techniques.

Simulation of the effect of pressure and temperature to the ECD and circulating pressure has been carried out using hydraulic mode in Landmark® Wellplan software using simulated well data by considering several assumptions. This simulation is very important to simulate the data available in order to correlate it with the real MPD operations. The simulation result is done by using three principle steps in order to simulate the MPD application in wellbore condition respect to pressure and temperature as main parameters. Firstly, the simulation is aimed to determine how the ECD and circulating pressure along the wellbore are changing when pressure and temperature effects are introduced with rheological properties of the drilling fluid. Secondly, the surface backpressures are applied in order to simulate the MPD applications with constant pump rate, the changes in ECD and circulating pressure are determined with constant mud circulating times for effect of temperature to take place. Thirdly, the temperature is then simulated for different mud circulating times with and without application of surface backpressures with constant pump rate and backpressure, in order to determine the ECD and circulating pressure along the wellbore.

The optimum pump rate and surface backpressure are determined in the simulation by analyzing the ECD and circulating pressure with different pump rates and applied surface backpressures. Results and discussions are mostly about the simulation of the equivalent circulating density and circulating pressure via depth with the pump rates, applied surface backpressures, and mud circulating times as the variables to simulate the pressure and temperature parameters.

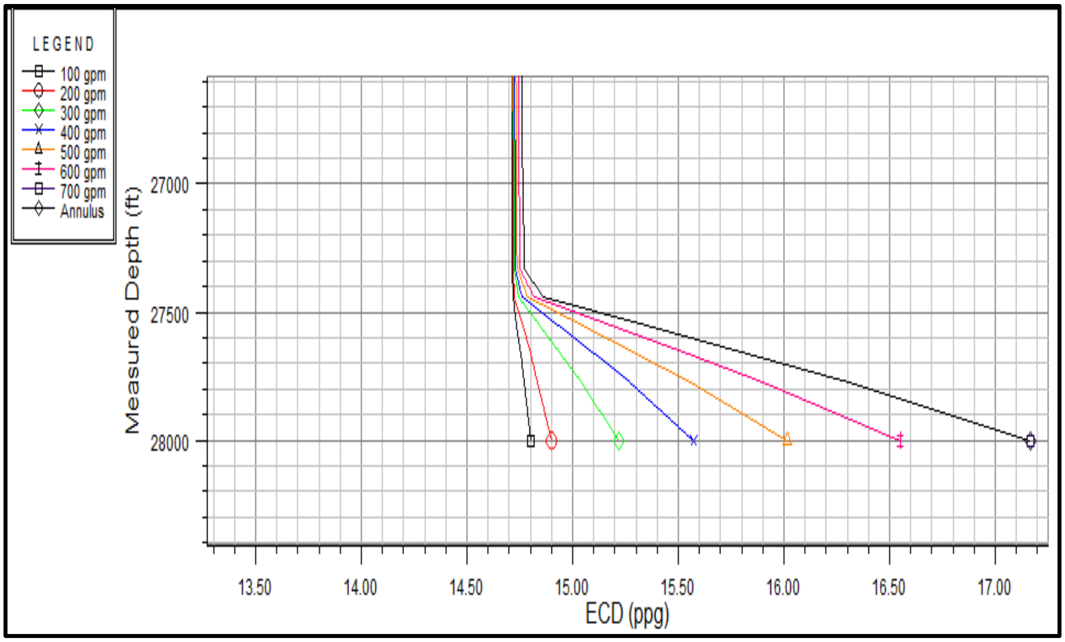


Figure 15: Equivalent Circulating Density with different pump rates

The equivalent circulating density (ECD) increased in the wellbore conditions as the pump rates increased and it moved toward the fracture pressure margin as shown in Figure 15. The circulating pressure also increased in the wellbore conditions as the pump rates increased as shown in Figure 16. It shows the higher pump rates will caused the formation to fracture with constant mud density (14.6 ppg) and mud circulating times (10 hours). This simulation is done without application of surface backpressure with normal wellbore condition by only using pump rates as the variable. The pump rates are used in order to simulate the pump pressure and estimation of drilling fluid pressure with consideration of hydrostatic pressure in the wellbore conditions. The result also shows the low pump rates gives low ECD and circulating pressures in the bottom-hole condition with hydrostatic pressure and temperature effect of the formation. The increases in the circulating pressure in high pump rate indicated the high pressure loss in the wellbore. As the pump rate increases, the pressure loss in the wellbore also increases. It is very important to determine optimum pump rate in order to optimize pressure loss and prevent fracture in the formation which is found in the simulation to be 400 gpm for both ECD and circulating pressure analysis. The pump rates used in the simulation were 100, 200, 300, 400, 500, 600, 700 gpm respectively.

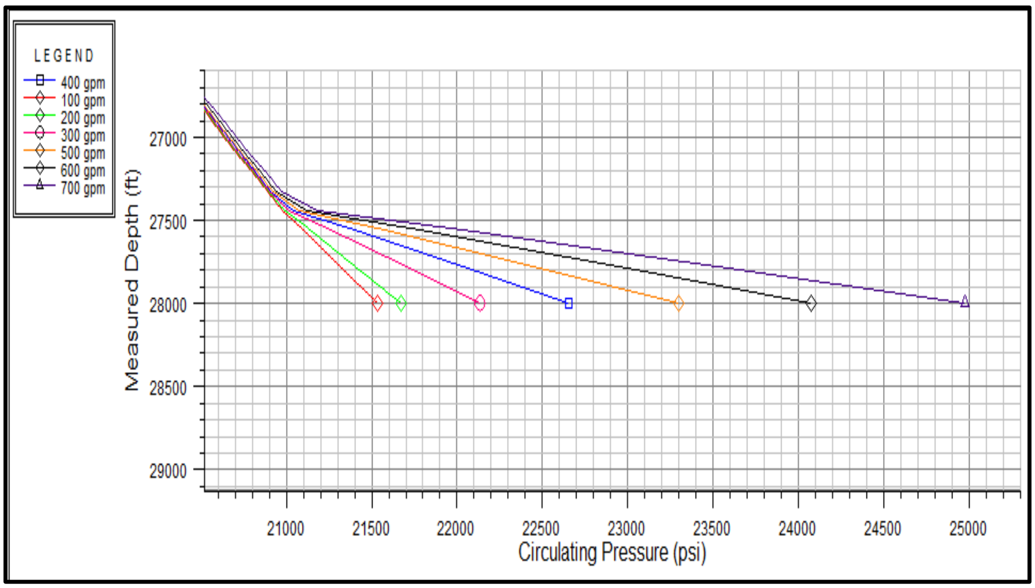


Figure 16: Circulating pressure with different pump rates

The ECD and circulating pressure changing in the wellbore with different backpressure applications under constant pump rate which is 400 gpm and mud circulating time (10 hours). This method was used to simulate the MPD applications with applied surface backpressure applications. The surface backpressures used in the simulation were 0, 200, 400, 600, 800 and 1000 psi. The result shows that, higher the backpressures, higher the ECD in wellbore condition as shown in Figure 17. The ECD were decreases gradually with increase in backpressure at the fluid column with the effect of hydrostatic pressure in height of fluid column or well depth and sudden increase at the bottom-hole conditions with effect of temperature and pressure of formation. The circulating pressure increases as the backpressures increases, indicated bit pressure loss at the bottom-hole conditions as shown in Figure 18. The sudden increase in ECD at the bottom-hole condition may be indicated by open-hole section without casing. The direct heat transfer from the formation and pressure in the wellbore increase the ECD but it controlled by applying surface backpressure with the decrease in ECD in the casing section with low ECD in the wellbore compared with the fracture pressure of the formation at constant pump rate. The optimum surface backpressure to be applied to the formation is determined which is 400 psi.

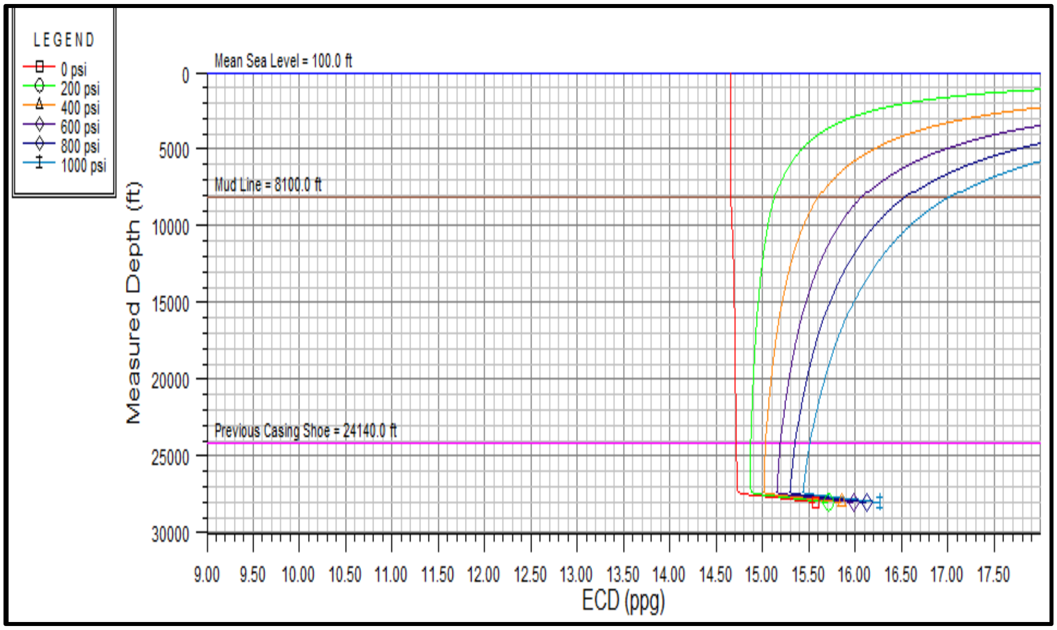


Figure 17: ECD with different backpressures under constant pump rate (400 gpm)

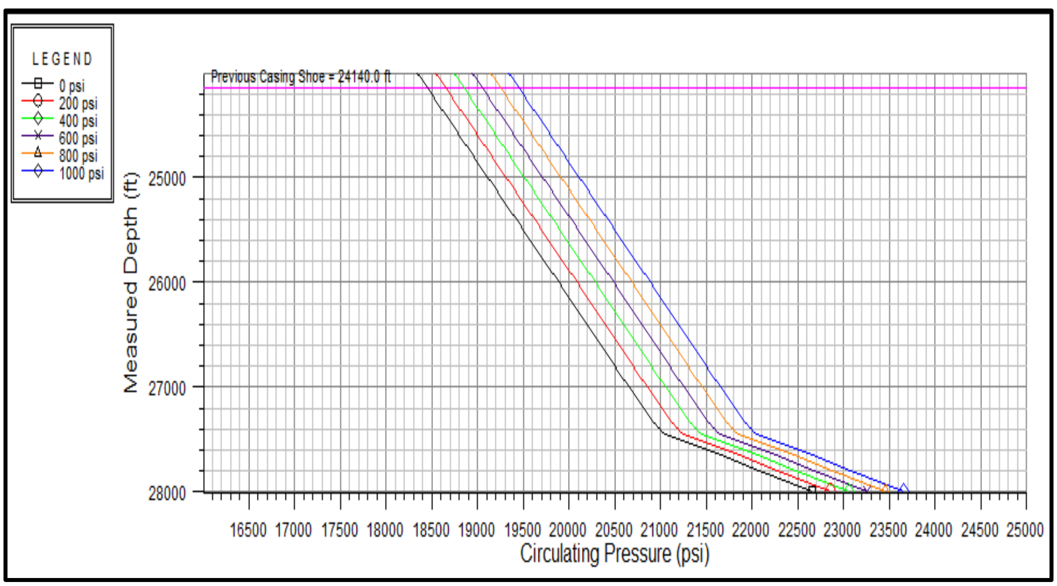


Figure 18: Circulating pressure with different backpressures under constant pump rate (400 gpm)

The effect of temperature is determined by simulating the ECD and circulating pressure along wellbore with different circulating times to takes the mud temperature effect in the wellbore without applied surface backpressures. Figure 19 and 20 shows the ECD and circulating pressure with mud temperature effect without backpressure application respectively. With the consideration of surface backpressures, the effect of temperature is simulated for ECD and circulating pressure with the 400 psi of surface backpressure as shown in Figure 21 and 22.

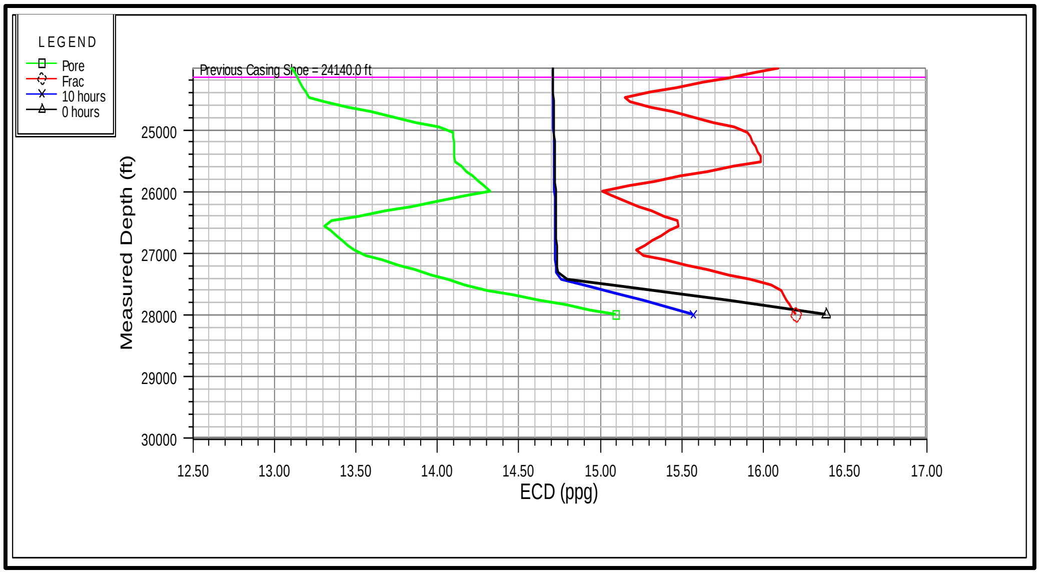


Figure 19: ECD with different mud circulating times (no backpressure)

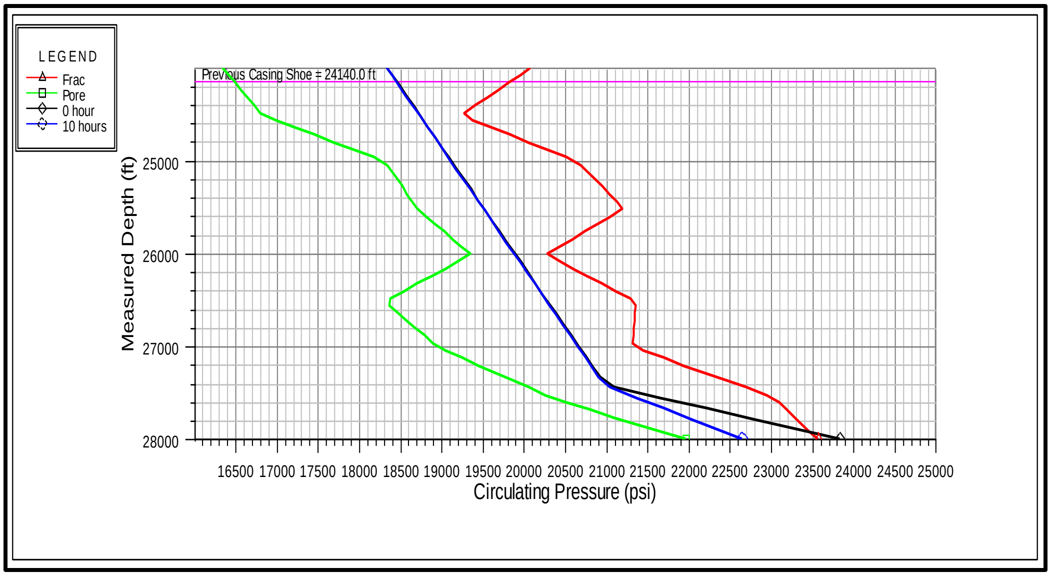


Figure 20: Circulating pressure with different mud circulating times (no backpressure)

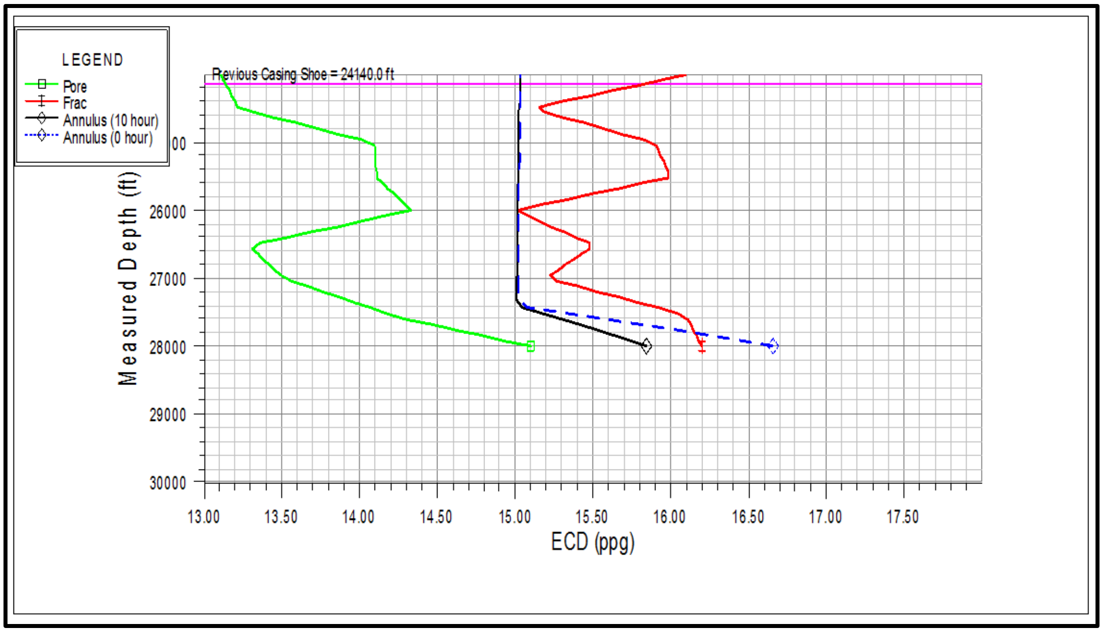


Figure 21: Equivalent circulating density with different mud circulating times (backpressure)

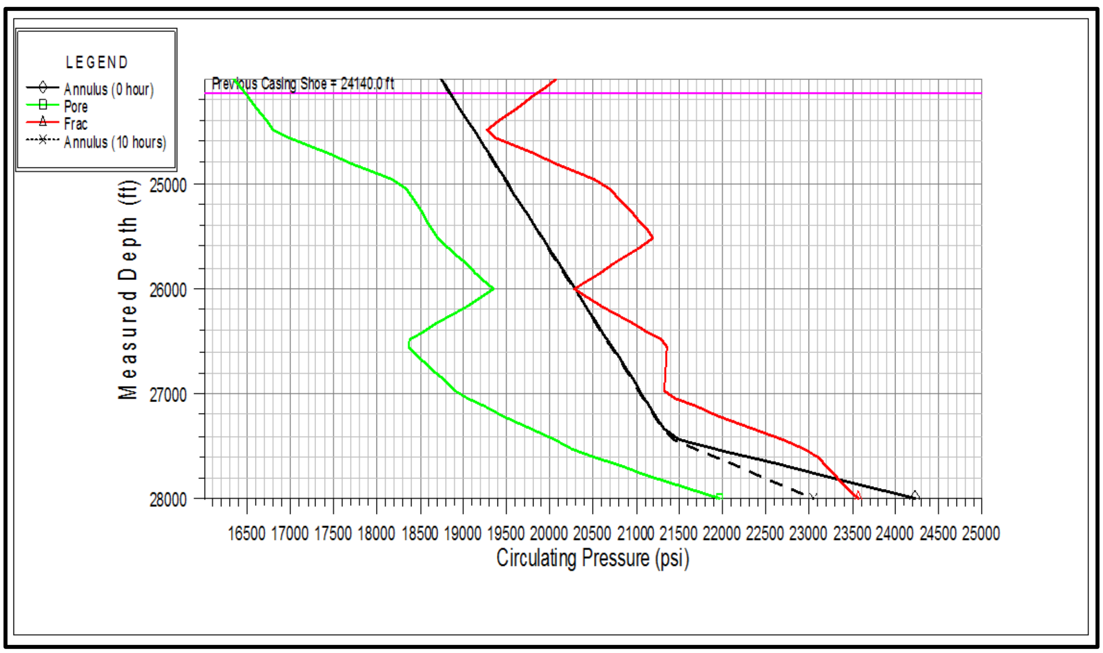


Figure 22: Circulating pressure with different mud circulating times (backpressure)

The increment in the equivalent mud weight of ECD and circulating pressures with and without backpressure application in two mud circulating times is tabulated in Table 5. The comparison of ECD and circulating pressure with different circulating times was analyzed.

Table 5: Comparison of ECD and circulating pressure for different cases

	ECD, ppg		Circulating Pressure, psi	
Mud circulating times, hours	0	10	0	10
Surface backpressure	16.65	15.85	24200	23100
No surface backpressure	16.40	15.55	23800	22600

The comparison of ECD and circulating pressure has been made due to the temperature effect by simulating mud circulating times and surface backpressure. It shows that the ECD and circulating pressure will increase in the low circulating times and approach to fracture margin in the mud operating window. Lower mud circulating times with higher the ECD and circulating pressure in the wellbore conditions. The ECD and circulating pressure are become higher when applying constant backpressure in the wellbore compared to the simulation without backpressure. This results may be indicated the temperature effect as lower circulating times result in higher ECD and circulating pressures without pressure consideration effect. For no surface backpressure simulation, there is an increment in ECD for 0 hour and 10 hours mud circulating times which is 0.8 in ppg, compared to the surface backpressure simulation with increment of 0.85 in ppg. It indicated the difference of 0.05 ppg between two cases as it implied the effect of surface backpressure in MPD application to the ECD. With higher surface backpressure, the ECD will become higher in low circulating times.

The circulating pressure also generated the same result as ECD with surface backpressure and without surface backpressure. For no surface backpressure, there is an increment in pressure between the mud circulating times which is 1200 in psi, compared to the surface backpressure application with increment of 1100 psi in psi. It indicated the difference of 100 psi between two cases as it implied the effect of surface backpressure to the circulating pressure. It is very large amount of pressure with the surface backpressure application includes mud temperature effect for wellbore conditions. This indication, without mud temperature effect consideration for MPD applications may result in wrong estimation of circulating pressure along wellbore in hundred of psi. The correct estimation of circulating pressure along wellbore is very important as it indicated the pressure losses across the bit and annulus. The higher circulating pressure along wellbore across the pressure in annulus, the higher in pressure losses. It will reduced the drilling fluid capability, rate of penetration, and increase the risk of formation fracture that result in fluid loss to the formation.

The temperature profile for annulus is then generated to see the temperature changing in term of depth in the wellbore conditions with different circulating times as shown in Figure 23.

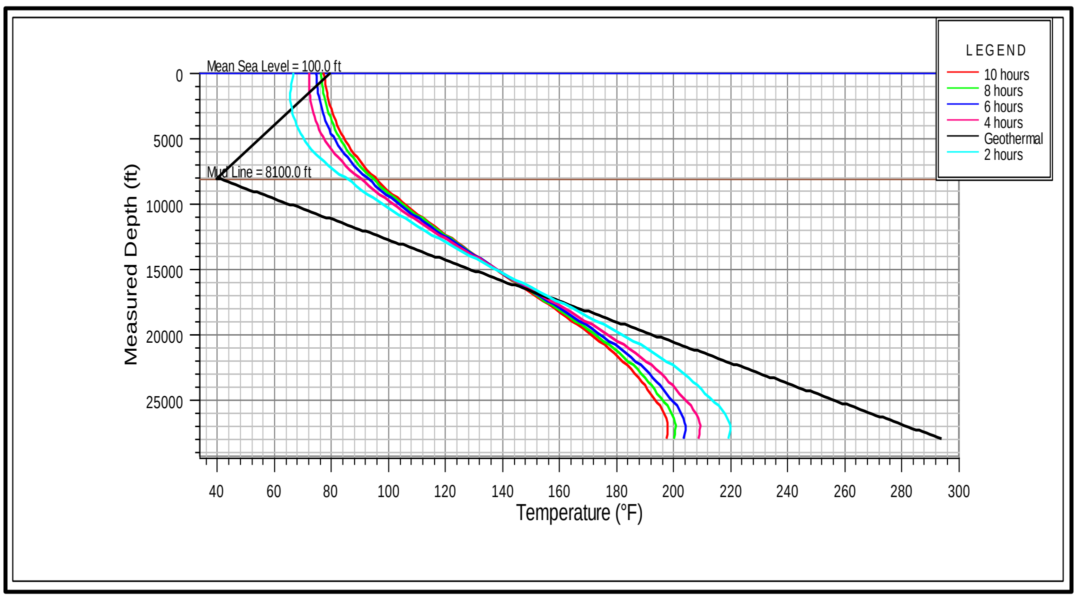


Figure 23: Annulus temperature profile for different circulating times

The temperature is lower at the beginning of the circulation for low circulating times and then increased to become higher at the wellbore conditions. For 2 hours circulation times, the temperature is lower than the temperature for 10 hours circulation times but, it increases as the depth increase and become higher at the bottom-hole depth. At the wellbore depth, 2 hours circulating times have higher reading in temperature compared to other circulating times with maximum circulating times was 10 hours in the simulation. The heat transfer effect may takes placed during circulation of drilling fluids throughout the wellbore with maximum temperature was 220 °F with geothermal temperature of formation at the wellbore conditions which is 298 °F. The result shows that low circulating times give the high temperature reading in the wellbore.

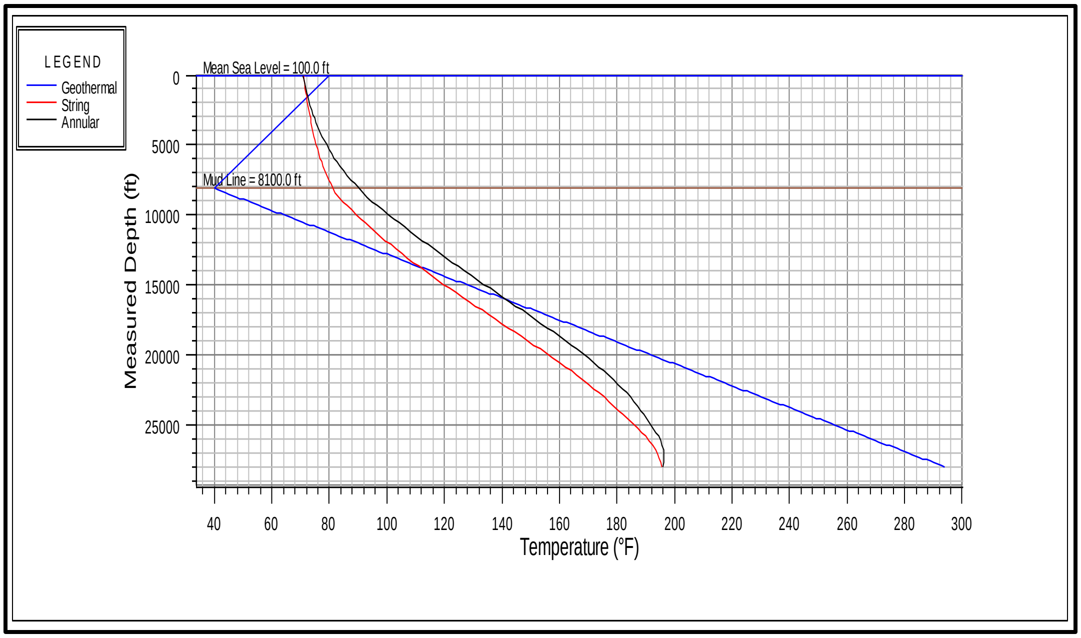


Figure 24: Temperature profile between annulus and drill string

The temperature profile between annulus and drill string is simulated with geothermal gradient as reference as shown in the Figure 24. It shows that, the annular temperature profile is slightly higher than drill string temperature profile. This indicated that the heat transfer between formation and fluid inside the annulus is higher compared to the heat transfer between fluid in drill string and annulus. In the wellbore conditions, the temperature for both string and annulus was same as the heat transfer is equilibrium and heat generated at the bit is neglected. Same as the temperature at the surface conditions, it assumed to be same as the inlet mud temperature which is 72 °F. The temperature in the wellbore conditions for both drill string and annulus as shown in the Figure 24 is 196 °F. It can be seen that, ECD and circulating pressures are significantly affected by pressure and temperatures with the application of backpressure in order to simulate MPD application in the simulation. Without consideration of pressure and temperature effect, it will lead to incorrect estimation of ECD and circulating pressure with high range of difference as shown and proved in the simulation using Landmark® Wellplan software.

CHAPTER 5

CONCLUSION AND RECOMMENDATION

In summary, this project is to study the effect of pressure and temperature variations to the drilling fluids properties in term of density during the application of Managed Pressure Drilling techniques. The rheological properties of the n-paraffin oil based mud such as plastic viscosity and yield point were determined using empirical model. The properties were used to simulate the equivalent circulating density (ECD) and circulating pressure in term of pressure and temperature variations using Landmark® Wellplan with wellbore conditions. Based on the rheological modeling using regression analysis and simulations that were performed, the following conclusions were drawn.

1) The plastic viscosity and yield point are very dependent on the effect of pressure and temperature in the wellbore conditions. The effect of temperature is more significant than the effect of pressure for these properties.
2) An empirical model that relates the change in density to the pressure and temperature variations has been developed for n-paraffin synthetic based mud for 14.6 ppg.
3) ECD and circulating pressure for n-paraffin synthetic based mud is strongly influenced by the effect of pressure and temperature during MPD applications.
4) ECD and circulating pressure profile with different pump rates gives the optimum pump rate which is 400 gpm.
5) ECD and circulating pressure profile with different surface backpressures under constant pump rate gives the optimum surface backpressure which is 400 psi.
6) The temperature profile for different mud circulating times has been simulated for ECD and circulating pressure with maximum temperature 220 ºF at wellbore for 2 hours circulating times of n-paraffin synthetic based mud.

In this project, it was described in term of how much the temperature and pressure will affect the correct application of MPD according to the drilling fluids density. The objectives of this study were achieved by simulate the simulation using Landmark® Wellplan. The simulator allows the simulation of ECD and circulating pressures along the wellbore using hydraulic model taking into account the temperature and pressure as the parameters.

For recommendation of this project, an improved simulator will be developed in near future to limit the restrictions in the assumptions for simulation by taking account the cutting transport, trajectory well and heat transfer. More rheological model will be included in the simulator for broad range of drilling fluid applications.

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APPENDICES

Table 1: Calculated plastic viscosity under pressure and temperature variations

Pressure, psi	Temperature, °F	PV ,cp
0	50	47.0331
	100	22.8735
	150	15.0037
	200	11.124
500	40	62.7629
	80	30.2967
	120	19.7884
	200	11.5707
	280	8.1255
2000	40	74.1814
	80	35.0316
	120	22.587
	200	12.9936
	280	9.0274
4000	40	92.1543
	80	42.2061
	120	26.7295
	200	15.0334
	280	10.2903
8000	40	139.3626
	80	59.8052
	120	36.4602
	200	19.5458
	280	12.963
12000	40	204.8522
	80	81.9311
	120	47.9334
	200	24.3968
	280	15.6364

Table 2: Calculated yield point under pressure and temperature

Pressure, psi	Temperature, °F	YP ,lb/100ft
0	50	36.5
	100	24
	150	18.5
	200	12
500	40	27
	80	8
	120	0
	200	3
	280	3.5
2000	40	28
	80	10
	120	3
	200	2
	280	3.5
4000	40	34
	80	10
	120	5
	200	2
	280	1.5
8000	40	-
	80	10
	120	4
	200	0
	280	0.5
12000	40	-
	80	17
	120	3
	200	3
	280	0.5

Table 3: Calculated change in density for n-paraffin based drilling fluid under pressure and temperature variations

Temperature, °F	**Pressure, psi**	**Change in density, ppg**
80	500	0.001
	1500	0.02
	2500	0.05
	3500	0.1
	4500	0.15
	5500	0.19
120	500	-0.09
	1500	-0.05
	2500	-0.02
	3500	0
	4500	0.02
	5500	0.05
160	500	-0.2
	1500	-0.15
	2500	-0.12
	3500	-0.1
	4500	-0.08
	5500	-0.01
200	500	-0.32
	1500	-0.28
	2500	-0.24
	3500	-0.2
	4500	-0.17
	5500	-0.12
240	500	-0.47
	1500	-0.4
	2500	-0.35
	3500	-0.3
	4500	-0.27
	5500	-0.21
280	500	-0.61
	1500	-0.57
	2500	-0.5
	3500	-0.44
	4500	-0.4
	5500	-0.35

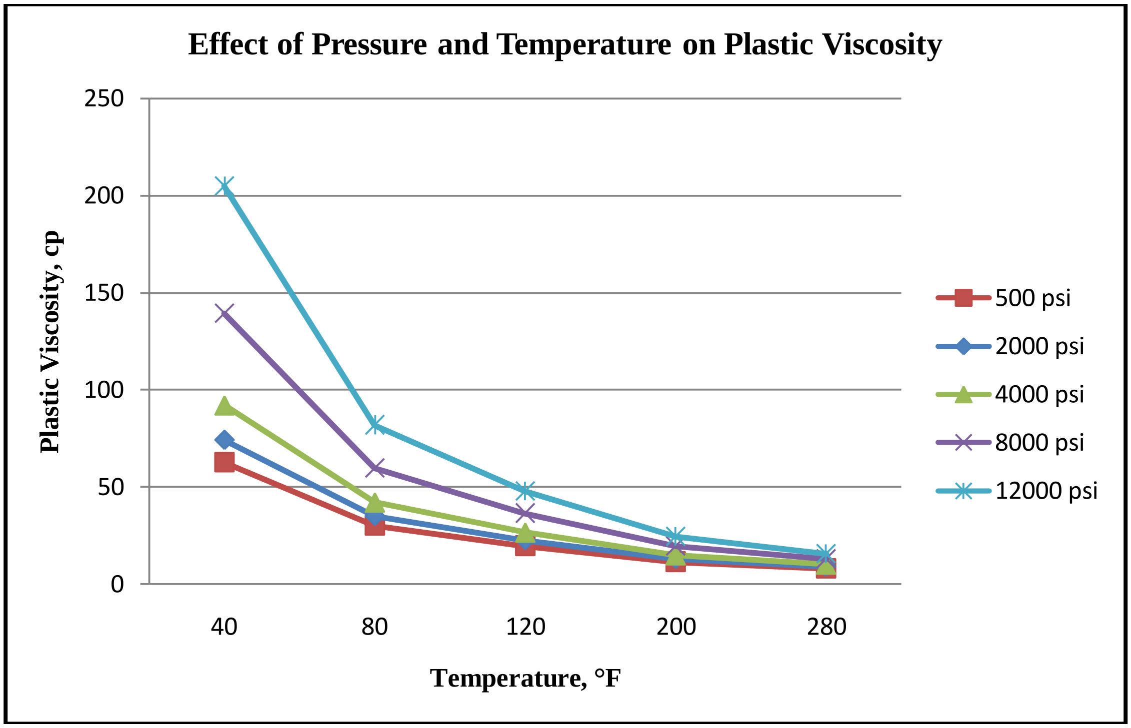

Figure 7: Effect of pressure and temperature on plastic viscosity (isobaric condition)

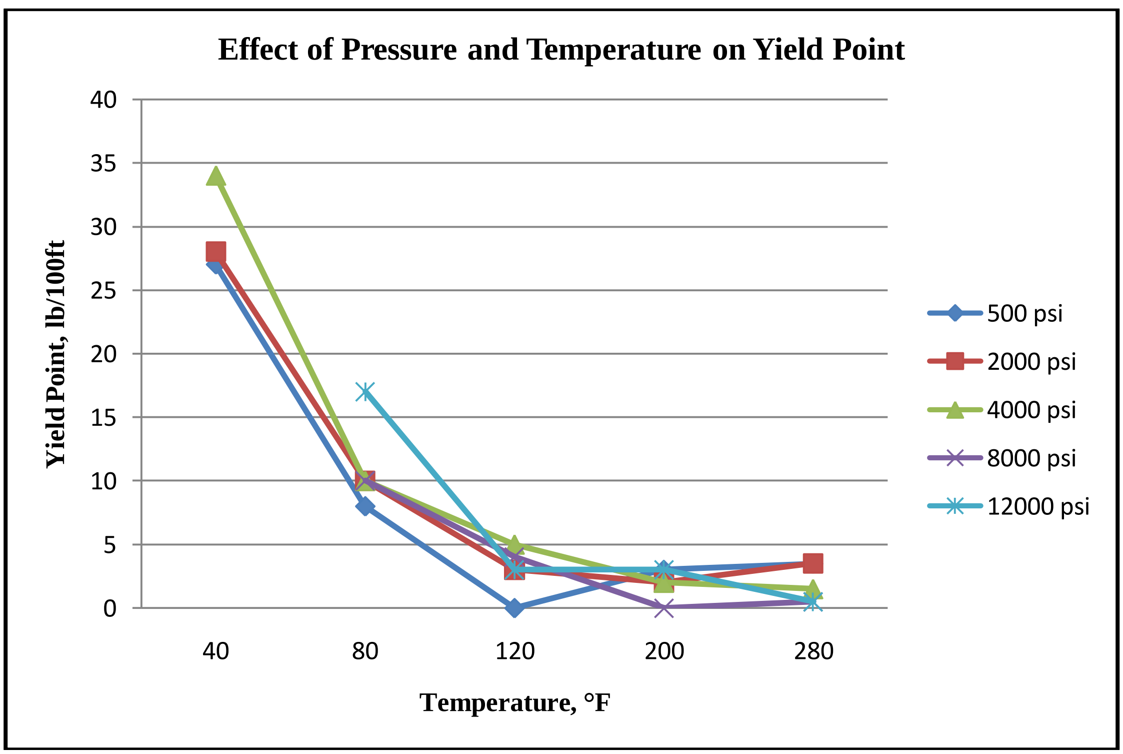

Figure 8: Effect or pressure and temperature on yield point (isobaric condition)

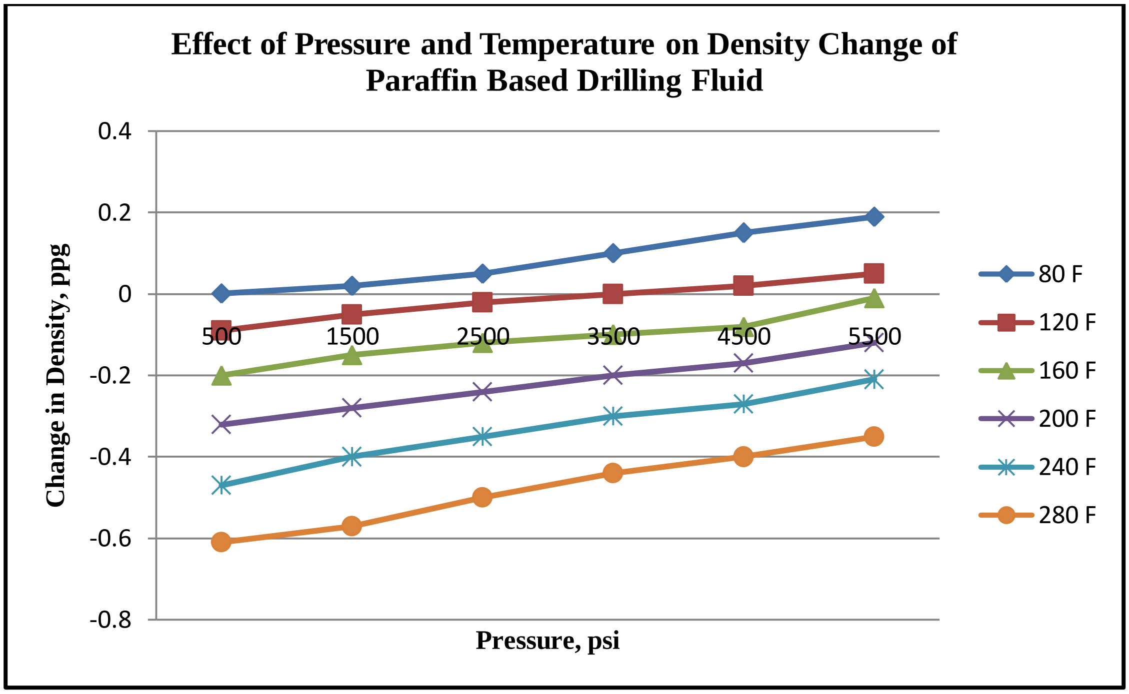

Figure 9: Effect of pressure and temperature on density change of paraffin based drilling fluid

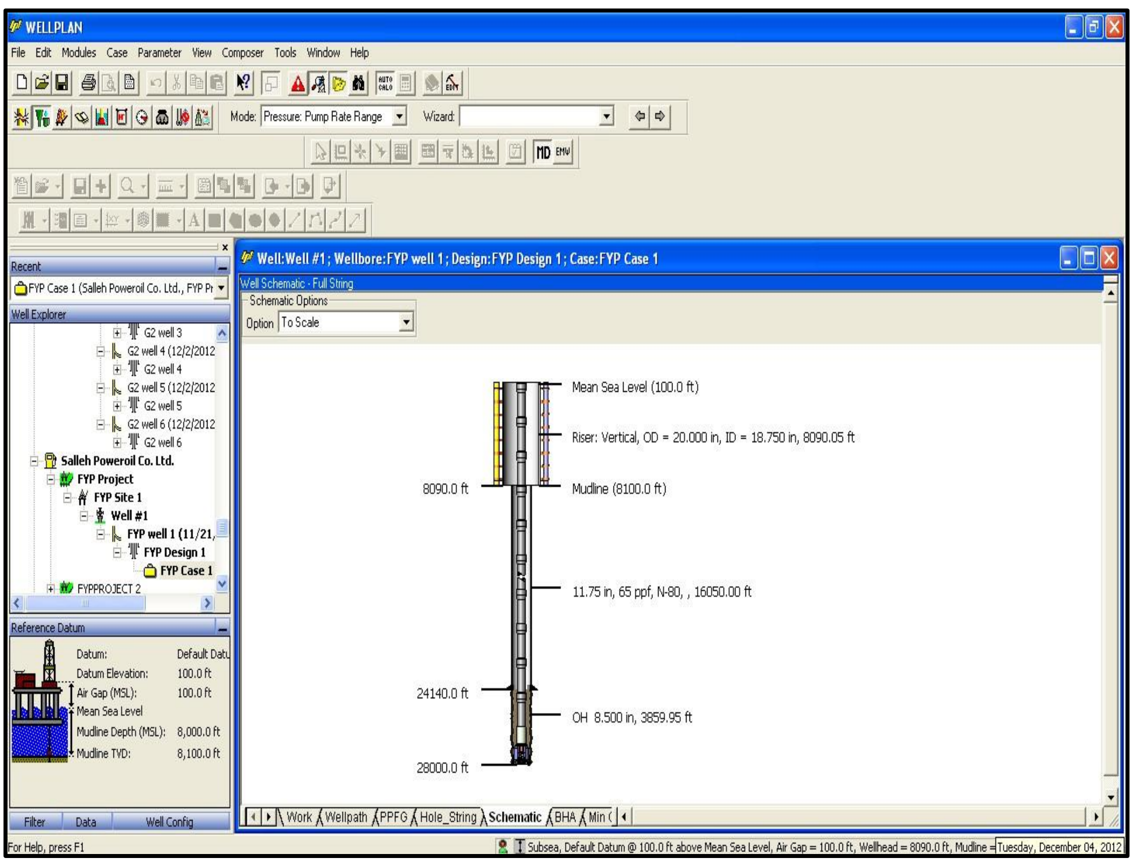

Figure 10: Landmark® Wellplan Software using Hydraulic Mode

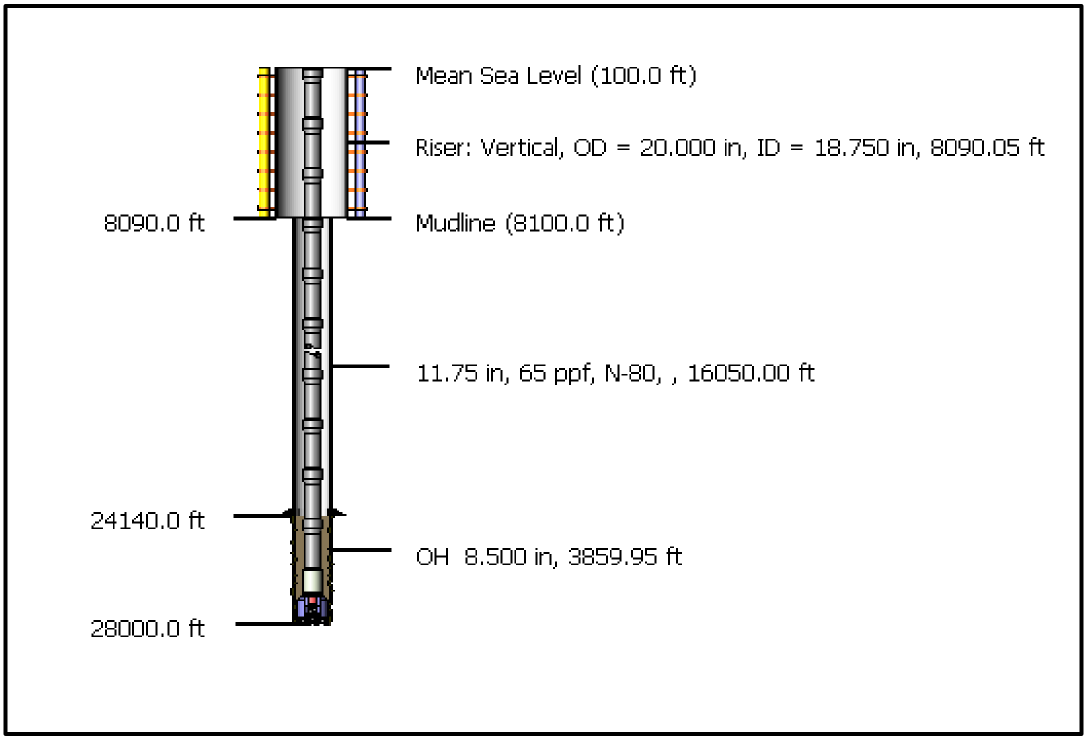

Figure 11: Wellbore configuration of Simulated Well

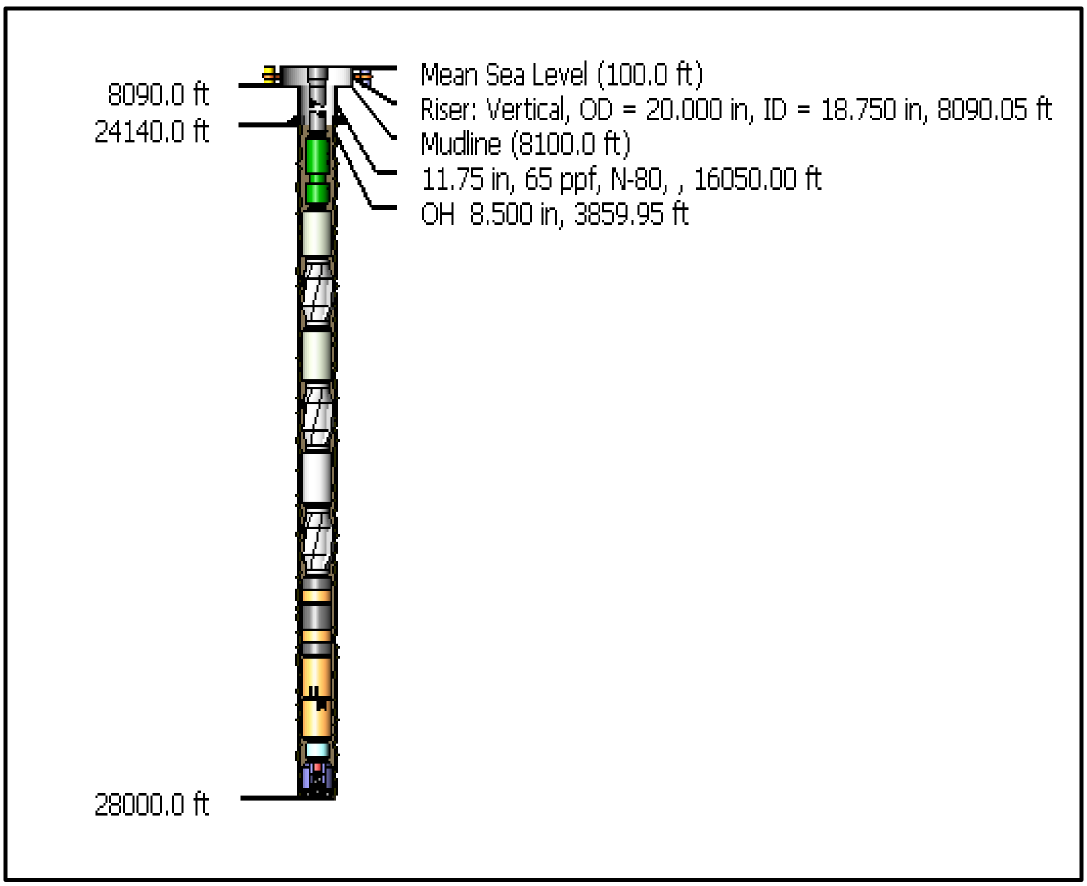

Figure 12: Down-hole drilling equipments diagram

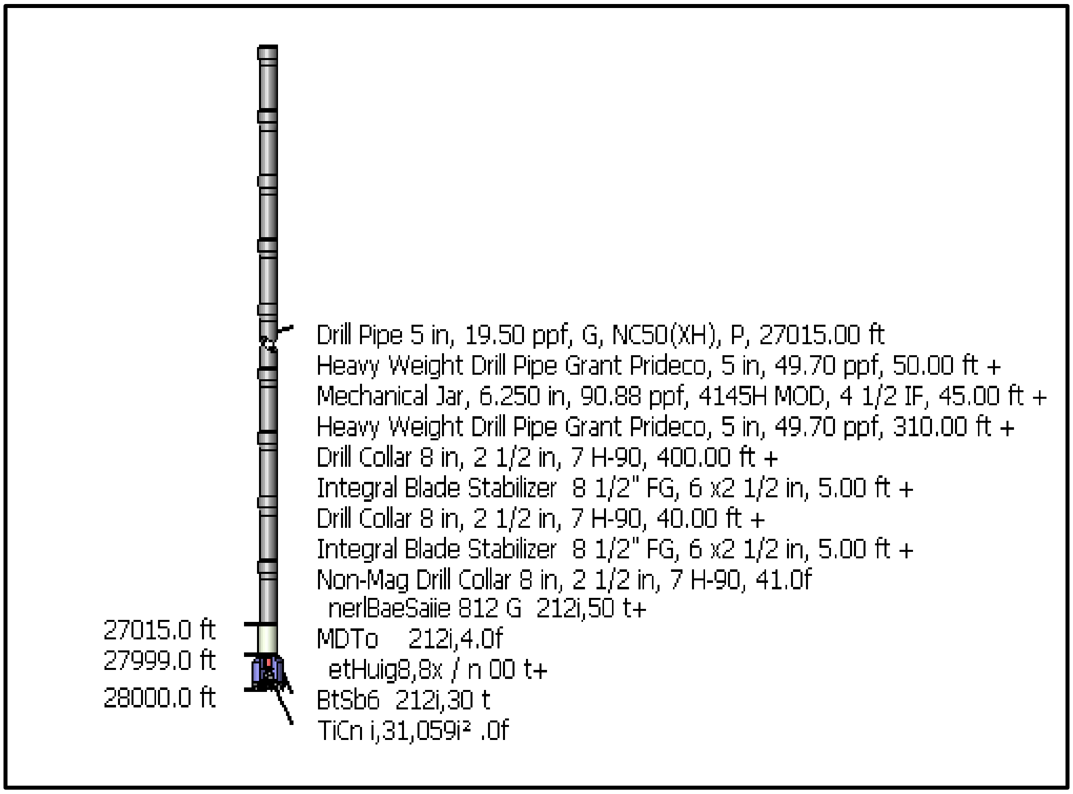

Figure 13: Bottom-hole Assembly (BHA) schematic diagram

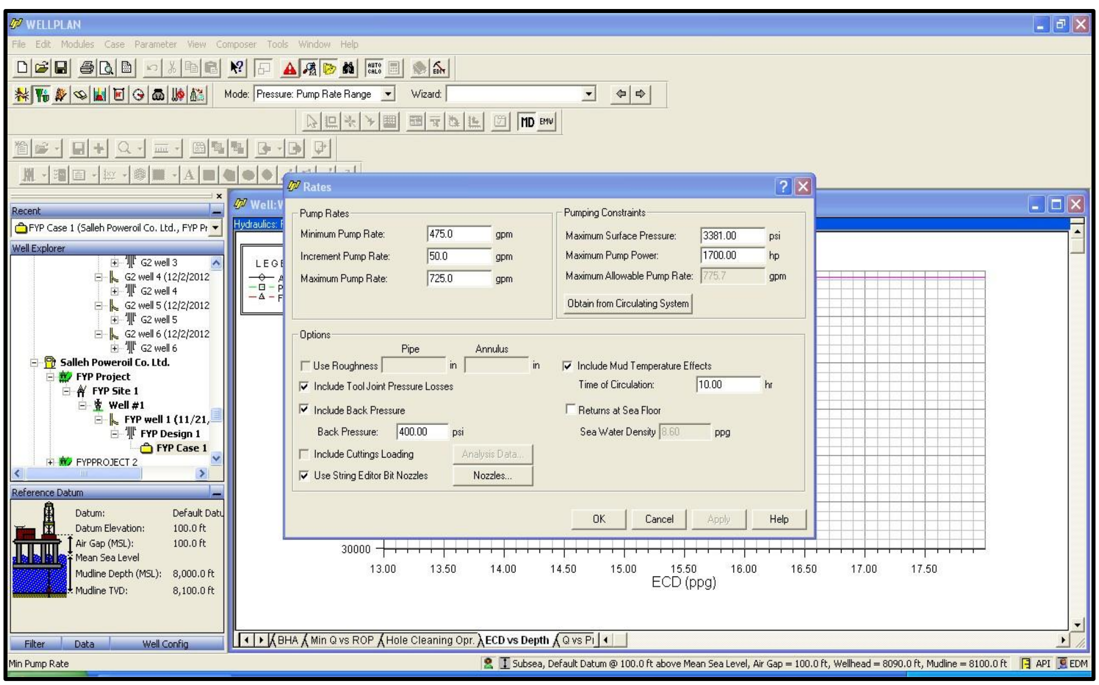

Figure 14: Data input for pump rates with backpressure and mud circulating times variables using Landmark® Wellplan