Optimal Simulation and Mathematical Correlation of Mud Weight for Effective Wellbore Stability Management

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Abstract—Wellbore instability is a problem that affects drilling activities. It is therefore important to provide an optimal solution that prevents or reduces the occurrence of wellbore collapse and not compromise the integrity of the well. In this study, work was done to assess the impact of several parameters including tubing pressure, tubing fluid temperature, length of tubing, gas density, liquid density, tubing hold-up and total mass flow on mass fraction of tubing muds were considered. Data points for this investigation were obtained using OLGA multiphase simulator. The results of the simulation (including the trend and plot data) were exported to MATLAB to develop a mud weight model (correlation) using the MATLAB regress function. The correlation was also validated using statistical techniques such as the R square and Significance F values. Comparison of the trend plots of the actual data points from OLGA and the predicted data points was also done to further prove the reliability of the correlation. The correlation predictions agreed with the OLGA results excellently with a relative error of less than 0.001 %. This study revealed that the tubing mud weight is significantly impacted on by variables like tubing holdup, tubing gas density, tubing liquid densities and the total mass flow. Whereas the tubing pressure, fluid temperature, and the tubing length have insignificant effects on the tubing mud weight. From the trend plots of the variables, it was deduced that as the tubing pressure increased, the temperature and the mud weight also increased. While, the total mass and volumetric flows reduced with increased tubing pressure. The effect of input data uncertainties on the developed correlation were also tested by using 22 observation points to predict tubing mud weight and calculating the resulting residual values. Over 90% of the residual values were negative and the percentage difference in mud weight between the first and the last observation points was approximately 4%. Hence, the effect of input data uncertainties on the developed correlation is insignificant. This report will serve as a template for drilling engineers, assisting them with a simple, fast and reliable technique for determining optimum drilling parameters with a lesser engineering exertion and drilling experience.

Index Terms—Mud Weight Model, Trend Plot, Uncertainties, Wellbore Instability.

I. INTRODUCTION

The problems that affect the stability of the wellbore is being increasingly looked at by different companies in the drilling sector of oil and gas. As drilling activities progress to more stringent conditions far from land, the urge for well operators to improve their business becomes very crucial [1]. Losses suffered due to collapse or fracture of the well has been estimated in billions of dollars globally. To improve safety and ensure smooth drilling operation,

priority is given in ensuring the stability of the wellbore is sustained, this will reduce impairments associated with design of the well, and its future performance once recovery of hydrocarbon commences. Understanding the circumstances that enable failure of underlying strata within the vicinity of the well is the concern of wellbore stability studies. Methods that give future outcomes have been used extensively to address rock mechanics plights which influence wellbore instability [2].

Unacceptable results which cannot be inferred on by drillers to use and design similar wells are due to increasing variations in wellbore stability studies or investigations. Results that are only focused around a point of interest are given by many wellbore stability models and correlations. The input information of lots of correlations are unknown and foggy. Definitely when these correlations have unknown input parameters, the insight on the output value will be completely inaccurate [3].

Drilling operators must change the load distribution by varying the force per unit area in the wellbore (mud in the well) to evade occurrences that may result in lack of success in well operations. Thus, it can infer that modifying the force per unit area of the mud could tackle or mitigate instability of wellbores [2]. Commonly, whatever the associated loads of the field or strength of formations, the drilling fluid pressure is made to prevent flow of fluids from the formation into the borehole. Realistically, the lower limit when drilling overbalance is 7 to 14 bars, or the equivalent density of the drilling fluid 12.6-21 lb/bbl greater than the force exerted by the formation should be obtained [4]. Rocks that possess very low strength will find it difficult to comply to this pressure demand unlike rocks that possess high strength. Since the forces which are originally existing in the rocks are greater than the pressure by fluids in the pores, the necessary pressure to keep in place the open hole is higher than that needed to hold or restrain the fluids [2]. Wellbore instability is propagated when there is a variation in the drilling fluid pressure and properties, and the temperature of the surrounding strata while drilling. Studies on effects that change with time are made harder to obtain because of these parameters [3].

Typically, the formation pressure from the fluids is lesser than the pressure in the well by the drilling fluid. By doing this, fluids from the drilled rocks do not enter the well. The success of overbalanced drilling is dependent on several considerations. The choice on mud weight is the most important [5]. According to [6], the drilling fluid design is the disparity between a good and bad drilling operation. A high mud density may lead to fracture and losses while low mud density may lead to collapse and cave-in of the well. Therefore, this study will develop a new wellbore stability

model that can determine the optimum drilling fluid density.

II. METHODOLOGY

Wellbore instability due to drilling fluid effect were simulated using OLGA software in order to determine the variables having the most significant effects on drilling fluid density and hence generating an equation which correlates the drilling fluid density (dependent variable) to the independent variables. From the output of the OLGA simulations, over 20 data points were generated for both the dependent and independent variables including tubing length, total mass flow, tubing pressure, tubing fluid temperature, mud density, tubing gas density, tubing liquid density, etc. which were exported to Excel and then to MATLAB. MATLAB regress function was used to develop a new wellbore stability model. Uncertainties and sensitivities of the input data were also tested by varying the values of the input data in subsequent simulations and checking their effects on the drilling fluid density model.

A. Data Collection

To run the simulation in OLGA, certain data were required as input data. Some of these data are shown in Table I. Table I shows the tubing length, tubing thickness, tubing material type, pressure, temperature, ambient temperature, drilling fluid type, drilling fluid density, and drilling fluid viscosity. These data were sourced from the reservoir and well unit of Schlumberger.

TABLE I: INPUT DATA (SOURCE: SCHLUMBERGER, 2016)

VARIABLE	VALUE
Tubing length	2900m
Tubing inlet pressure	186 bar
Tubing thickness	3m
Tubing material	Steel
Tubing fluid inlet temperature	80 deg.C
Ambient temperature	4 deg.C
Drilling fluid type	Water based mud
Drilling fluid density	600-2400 kg/m ³
Drilling fluid viscosity	0.0001-1 N-s/m ²

III. RESULT AND DISCUSSION

Fig. 1. Well Source-Tubing-Wellhead Schematic

Fig.1 shows the flow path schematic for this study consisting of a tubing having a length of 2900m connecting the well source to the wellhead.

Fig. 2. Trend Plot of Tubing Pressure

Fig. 2 shows that the pressure of the tubing started rising gradually from $t = 0$ sec and pressure of 186 bar until it got to a pressure of about 248 bar after about 3800 seconds. Then, at this point the pressure dropped a bit to 238 bar after 5200 seconds, and remained relatively the same for the rest of the operation. The increase in pressure observed could be due to the increase in mud volume pumped into the tubing from the surface.

Fig. 3. Trend Plot of total mass flow

Fig. 3 shows that the total mass flow gradually dropped from 62 kg/s at $t = 0$ sec, to 60 kg/s at $t = 1800$ secs. From this time, the total mass flow remained the same till at $t = 3800$ secs. Beyond this time, the tubing system experienced a sharp drop in mass flow from 60 kg/s to 0 kg/s at $t = 5200$ secs. Beyond this point, there was no further increase or decrease in mass flow in the tubing system.

From Fig.2 and Fig.3, it could be observed that both pressure and mass flow drops in the tubing system happened at the same time, which was at 5200 seconds.

Fig. 4. Trend Plot of the Tubing Fluid Temperature

Fig. 4 shows that the fluid temperature in the tubing

increased gradually from 79.92 oC at t = 0 sec. to 82 oC after 2000 seconds. Beyond this point, there was a gradual drop in temperature till about t = 5200 secs and from t = 5200 secs, there was a sharp drop in tubing fluid temperature which continued for the rest of the operation. It can also be observed that the time (at t = 5200secs) the tubing fluid temperature experienced a sharp decrease coincided with the time pressure and mass flow also dropped. The drop of the mass flow was also a sharp one just like that of tubing fluid temperature.

Fig. 5. Trend plot of total volume flow

Fig. 5 shows that the total volumetric flow dropped from 6000 m³/d at t = 0 sec to about 4500 m³/d at t = 1800 secs. Just after this point, the volumetric flow remained the same and then experienced a sharp decline from 4500 m³/d at t = 3700 secs to 0 m³/d at t = 5200 secs. Beyond this point, there was no further increase or decrease of volumetric flow in the tubing system.

Fig. 6. Profile Plot of the Mass (weight) of mud in the Tubing

Fig. 6 shows that the mud weight (expressed as mass fraction of the mud) in the tubing increased sharply from 0.895 at t = 0, to 1 at t = 2000 sec. After this point, mud weight remained the same for the rest of the operation.

From the plots, it can be deduced that as the tubing pressure was increasing, the temperature and the mud weight were also increasing. Whereas, the total mass and volumetric flows reduced with increase in tubing pressure.

A. Correlation for Tubing Mud Weight

From the outcome of the OLGA simulations, 22 data points were generated containing one dependent variable which is the mud weight in the tubing, and six independent variable which include: tubing length, tubing pressure, tubing holdup, tubing fluid temperature, tubing total density of liquid and tubing density of gas (see table I).

The MATLAB regress function generated seven coefficients including that of the intercept value which is

approximately 3.072, the coefficient of the tubing length is approximately -1.373×10^{-5} , the coefficient of the tubing pressure is approximately -0.0011, the coefficient of the tubing holdup is approximately 0.273, the coefficient of the tubing fluid temperature is approximately -0.0126, the coefficient of the tubing density of gas is approximately 4.33×10^{-4} , and the coefficient of the total tubing density of liquid is approximately 5.86×10^{-4} . Arranging these coefficients and putting them in the form of a linear regression equation 'Y=Ax1+Bx2+C' resulted to equation 1, which is the drilling mud weight correlation developed in this study.

$$\begin{aligned} \text{Mud}_{\text{weight}} = & 3.072 + 0.273 H_{ol} - 1.373 \times 10^{-5} L (m) - \\ & 0.0011 P(\text{bara}) + 4.33 \times 10^{-4} ROG \left(\frac{kg}{m^3} \right) + \\ & 5.86 \times 10^{-4} ROL \left(\frac{kg}{m^3} \right) - 0.0126 T_m(^{\circ}C) + 3.662 \times 10^{-5} \\ & G_T \left(\frac{kg}{s} \right) \end{aligned} \quad (1)$$

where, the **Mud_{weight}** is expressed as tubing mass fraction of all muds in the tubing.

TABLE II: SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.999836441
R Square	0.999672908
Adjusted R Square	0.999509362
Standard Error	0.000288772
Observations	22

From table II, R Square equals approximately 1, which represents a perfect fit. This implies that over 99% of the variations in the tubing mud weight is influenced by the independent parameters: Tubing pressure, Tubing length, Tubing fluid temperature, Tubing holdup, Tubing liquid density, Tubing gas density and Total mass flow. The closer to 1, the better the regression line fits the actual data. Therefore, the developed correlation is very reliable.

To confirm if the result (the developed correlation) is statistically significantly, the Significance F values is looked at. From table III, the Significance F is approximately 2.71×10^{-23} and this value is far below 0.05. This factor also confirms the reliability of the developed correlation (equation 1) for accurately estimating the tubing mud weight.

TABLE III: SIGNIFICANCE F FOR TUBING MUD WEIGHT CORRELATION

	df	SS	MS	F	Significance F
Regression	7	0.003568016	0.00051	6112.491	2.70836E-23
Residual	14	1.16745E-06	8.34E-08		
Total	21	0.003569184

Fig. 7. Trend plots of Actual and Predicted Mud Weights

From Fig.7, it can be seen that the curve for the predicted mud weight completely superimposed that of the actual mud weight curve. This implies a high accuracy and reliability of the developed correlation in estimating drilling mud weight. Therefore, when conducting experiments, carrying out simulations or the deployment of other drilling fluid density estimation techniques becomes unviable or uneconomical, equation 1 can reliably be used as a tool to accurately estimate the optimum drilling mud weight.

B. Test for Input Data Sensitivity

TABLE IV: RESIDUAL OUTPUT

Observation	Predicted Mud weight	Residuals
1	0.893685075	-2.07457E-06
2	0.893644097	-7.09731E-06
3	0.893487759	0.000102241
4	0.893242992	-0.000199992
5	0.892895958	9.60421E-05
6	0.892886	-0.000117
7	0.892485423	0.000185577
8	0.892442041	0.000132959
9	0.89255732	-9.83205E-05
10	0.892592462	-0.000269462
11	0.892253659	0.000310341
12	0.892965504	-0.000256504
13	0.895476573	-3.57349E-06
14	0.895572634	1.9366E-05
15	0.895245411	0.000366589
16	0.895360242	0.000267758
17	0.896244938	-0.000583938
18	0.896072615	-0.000331615
19	0.895522101	0.000369899
20	0.930286111	1.3889E-05
21	0.930872797	-3.6797E-05
22	0.931381287	4.17125E-05

The residuals reveal how far or how close the actual data points (for this study, the data points from OLGA) are from the predicted data points (data points predicted using the developed correlations).

From the residual values, the effect of uncertainties of the input data is very insignificant as most of the differences are negative. Also, the percentage difference in mud weight between the first and the last observation points is just approximately 4%. Therefore, the drilling fluid model developed in this study is not significantly impacted on by variations and uncertainties in input data.

IV. CONCLUSION

A predictive model for optimum mud weight in a well was developed and successfully validated. The study revealed that the tubing mud weight is significantly impacted on by variables like tubing holdup, tubing gas density, tubing liquid densities and the total mass flow. Whereas the tubing pressure, fluid temperature, and the tubing length have insignificant effects on the tubing mud weight. From the trend plots of the variables, it was deduced that as the tubing pressure increased, the temperature and the mud weight also increased. While, the total mass and volumetric flows reduced with increased tubing pressure. Over 90% of the residual values were negative and the percentage difference in mud weight between the first and the last observation points was approximately 4%. Hence, the effect of input data uncertainties on the developed correlation is insignificant.

V. RECOMMENDATION

Data points for this study were generated via simulation using OLGA. However, it will be very good to further validate the correlation and the outcomes of this study using experimental data in the future.

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