Development of a Model for Accurate Determination of Fluid Density and Improvement of Borehole Stability Predictions using a Simulator

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Abstract: **In this paper, work was carried out to investigate 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. 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. Where as 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 paper could serve as a template for drilling engineers, assisting them with a simple, fast and reliable technique for determining optimum drilling parameters with a minimum engineering effort and drilling experience.**

Keywords: **Fluid density, Mud weight, Wellbore stability, OLGA, Correlation**

I. INTRODUCTION

It has been predicted that wellbore instabilities have yielded a loss of approximately US$ 1 billion per annum globally. Maintaining wellbore stability is a significant element in promoting safety and drilling efficiency while reducing issues, expenses associated with well construction and production operations. Wellbore stability entails ascertaining the conditions which marks the onset of failure in the rock surrounding the wellbore. Tremendous effort has been directed towards finding solutions for rock mechanics issues associated with wellbore instabilities via provision of predictive techniques (Al-Ajmi, 2006). A number of inconsistencies impact on many previous wellbore stability analyses, leading to unreliable outcomes, or results that cannot be generalized with respect to other well configurations by well designers. Most wellbore fracture and collapse models give single point estimates. The model input data may be unreliable. Inability to take into account these uncertainties has resulted to unreliable estimations (John *et al*., 2014).

As per Mostafavi *et al*. (2011), among the reasons for pre-drill analysis is to identify upper and lower pressure boundaries for downhole pressure. A number of variables are needed, some of which are susceptible to inconsistencies as a result of measurement errors. Another source of input uncertainties is the systemic error as a result of human incomplete understanding of subsurface strata (Okoro, 2020). Analytical models utilised for wellbore stability analysis are prone to giving unreliable outcomes. Mathematical modeling algorithms just attempt to approximate physical processes, and they are not accurate representatives of the issues under study. The modelers have to take note of the unreliability and limitations of these physical models. As a result, unreliable results comes from the differences in input data and uncertainties that come from the wellbore stability modeling strategies (Al-Ajmi, 2006).

Expected outcomes give no clue about uncertainty (Bratvold & Begg, 2010). Wellbore stability is controlled by the *in situ* stress system. When a well is drilled, the rock around the hole must bear the load that was initially taken by the removed rock. Thus, the *in situ* stresses are greatly modified near the wall of the wellbore. This is shown by a production of an elevated stress within the wall of the well, that is, a stress concentration. The stress concentration has the capacity to cause rock failure of the wellbore wall, depending on the existing rock strength. The primary problem is to be aware, and have the capacity to estimate the response of the rock to the chnaged mechanical loading. This is a standardl, though not very common, rock mechanics issue (Al-Ajmi, 2006).

To prevent wellbore collapse, drilling engineers should optimise the stress concentration effectively via changing the applied internal wellbore pressure (*i.e*., mud pressure) and the orientation of the borehole as per the *in situ* stresses. Generally, the likelihood for alteration of the borehole orientation is limited. It is hence obvious that wellbore instability could be avoided by primarily adjusting the mud pressure (Al-Ajmi, 2006). Conventionally, the mud pressure is configured to restrict flow of the pore fluid into the well, irrespective of the rock strength and the field stresses. Practically, the minimum safe overbalance pressure (well pressure - pore pressure) of about 100-200 psi, or a mud density of 0.3 to 0.5 lb/gal over the formation pore pressure, is maintained (Awal *et al*., 2001). This may pose no issue in competent rocks, but could cause mechanical instability in weak rocks. In general, the mud pressure needed to support the borehole wall is greater than that needed to balance and contain fluids, as a result of the *in situ* stresses which are more than the formation pressure (Al-Ajmi, 2006).

Unplanned operations because of stress induced borehole failure causes loss of time and often times equipment represent about 10% of drilling costs (Aadnoy & Ong, 2003).

In addition to these dominant variables, borehole stability may directly or indirectly be affected by the following variables: (a) mud chemistry, (b) temperature effects and (c) time-dependent effects (John *et al*., 2014).

Temperature variations as a result of mud circulation while drilling could change the rock properties (Fjaer*et al*., 2008). The variation in rock properties may decrease or increase borehole failure depending on the thermal effect. The mud pressure and properties, and the temperature in the rock may change during drilling operations, which in turn promotes borehole instability (Okoro, 2018). All these variables make it more challenging to directly analyse the time-dependent impacts (John *et al*., 2014).

In conventional drilling, mud weight is selected such that the well pressure is greater than the pore pressure. This is to avoid entry of the formation fluid into the hole. Many elements impact on the success of overbalanced drilling operation. The most significant is the mud weight selection (Mahmood *et al*., 2016). As per Aadnøy (2010), the difference between success and failure is mostly a function of the mud program. Too low a mud weight could cause collapse and fill problems whereas too high a mud weight could cause mud losses or differential sticking (John *et al*., 2014).

In spite of the great efforts made over the past years, wellbore stability issues continue to be encountered while drilling. The practical impact of wellbore instability are primarily the failure of the wall of the wellbore (Aadnoy and Ong, 2003). The large differences in drilling conditions experienced under field conditions pose challenges with respect to establishing general rules of operation for maximum drilling efficiency as per drilling fluid parameters (Mahmood *et al*., 2016). Field encounters just give the basis for operations in a specific field, however, frequent testing is overly expensive. Most of the existing models are fanciful and need a lot of variables and calculations that render them less attractive to drillers who are making efforts to reduce the downtime to as low as practicably possible (Onuka & Okoro, 2019). These models are a function of the data from the core which are often not real time in solving the wellbore problem (John *et al*., 2014). Sequel to this, a predictive technique that considers the significant wellbore variables with less engineering effort and drilling experience is required. This paper developed a new wellbore stability correlation that can ascertain the optimum drilling fluid density. The aim is to enhance borehole stability estimations and predictions, so as to minimize wellbore stability issues encountered while drilling. The correlation accounts for a number of wellbore parameters in order to estimate the critical drilling fluid density while drilling. This paper should be of huge significance to geomechanics engineers, drilling engineers, geologists, geophysicists, and petrophysicists as it provides a simple correlation for estimating critical mud weight.

II. METHODOLOGY

Description of Problem

As more field projects are sited offshore, it is significant to overcome the difficulties associated with wellbore stability. This will make well operations easier to conduct and maintain as oil and gas are explored in harsher environment. Many parameters and elements impact on the success of overbalanced drilling operation and wellbore stability. The most significant is the mud weight selection (Mahmood *et al*., 2016).

In this paper, wellbore instability due to drilling fluid effect was modelled using OLGA simulator. The profile data points from OLGA were exported to Excel and then to MATLAB and were used to develop wellbore stability model that determined the optimum drilling fluid density.

To run the simulation in OLGA, certain data were required as input data. Some of these data are shown in Table 1. Table 1 shows the tubing length, tubing thickness, tubing material type, pressure, temperature, ambient temperature, drilling fluid type, drilling fluid density, and drilling fluid viscosity.

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.

OLGA

OLGA provides a wide range of options for mimicking flows between the multiphase fluids flowing in flowline networks, wells and the ambient environment. With full network capability, converging and diverging transport and process networks, and closed loops, the OLGA simulator offers insight into the dynamic flow behavior in wells, pipelines, and process equipment. This flexibility permits engineers to model a range of production systems for any field configuration and ascertain the optimal design, operational process, and risk-aversion approaches.

With the OLGA simulator, well engineers can design and configure a virtual well to study possible scenarios, analyse well flow issues, and estimate outcomes of well operations. Well engineers have observed improvements to their engineering designs, guaranteeing long-term production optimization not just for conventional wells, but also for wells with advanced completions and complex geometries (for instance., long horizontal, multilayer, multilateral, large-bore, and undulating trajectories).

Steps to Simulate Wellbore Instability with OLGA:

1. Launch the OLGA simulator
2. Click on file
3. Click on new case
4. Choose FA-models
5. Click on drilling fluids
6. Input the necessary data.
7. Run the simulation

Table 1: Input Data

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

MATLAB

MATLAB which stands for Matrix Laboratory, is a multi-paradigm numerical computing environment and proprietary programming language developed by MathWorks. MATLAB permits matrix computations, plotting of functions and data, execution of algorithms, establishment of user interfaces. It integrates a desktop environment tuned for iterative procedures and design processes with a programming language that depicts matrix and array mathematics directly. It incorporates the Live Editor for developing scripts that integrate code, output, and formatted text in an executable notebook. MATLAB toolboxes are professionally created, rigorously analysed, and wholly documented. MATLAB apps permit users to observe how varying algorithms work with their data. Iteration is done until the user gets the outcomes her or she desires, after which the user automatically generates a MATLAB code to reproduce or automate his/her work.

Steps for Developing Well Stability Model Using MATLAB

1. Launch MATLAB
2. Click on import file and navigate through to the Excel file location
3. Click on import the selection, it will be observed that the trend and profile data are now on the MATLAB workspace.
4. Write a function (scatter {x,y,a,c..}). The scatter function is written for the number of variables being analysed.
5. On the scatter plot that displays, click on tools.
6. Select basic fittings, click on linear and click on show equations. The dependent variable in the developed wellbore stability model was the mud density.
7. Or, instead of using the scatter function, use regress function to generate the coefficients of the independent variables that constitutes the correlation.

III. RESULTS AND DISCUSSIONS

Trend and Profile Plots of the Drilling Parameters

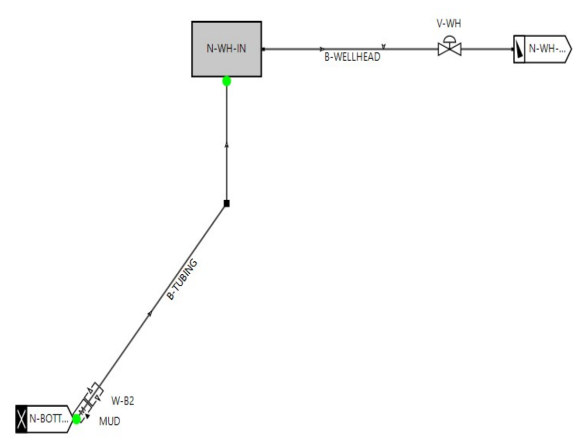

Fig 1 show the flow paths chematic for this study consisting of a tubing having a length of2900m connecting the well source to the wellhead.

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 bara 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 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 figures 2 and 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 shows that the fluid temperature in the tubing increased gradually from 79.92 ^{o}C at t= 0 sec. to 82 ^{o}C 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.

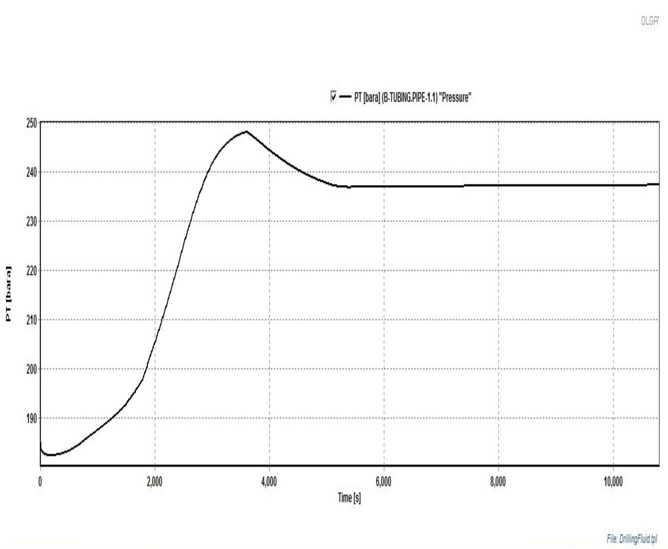

Figure 2: Trend Plot of Tubing Pressure

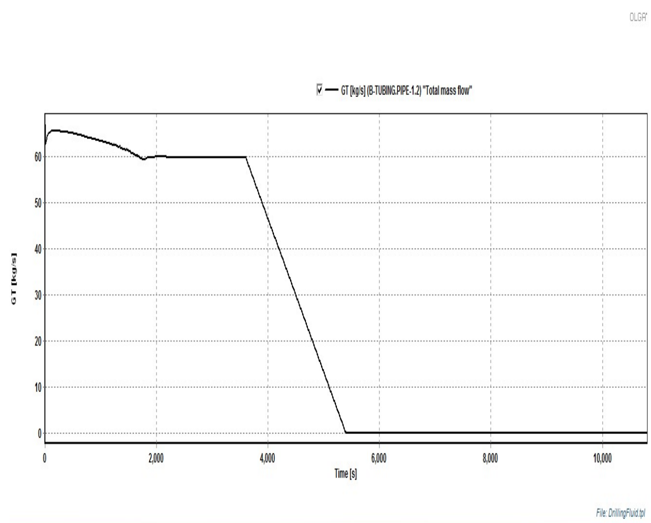

Figure 3: Trend Plot of total mass flow

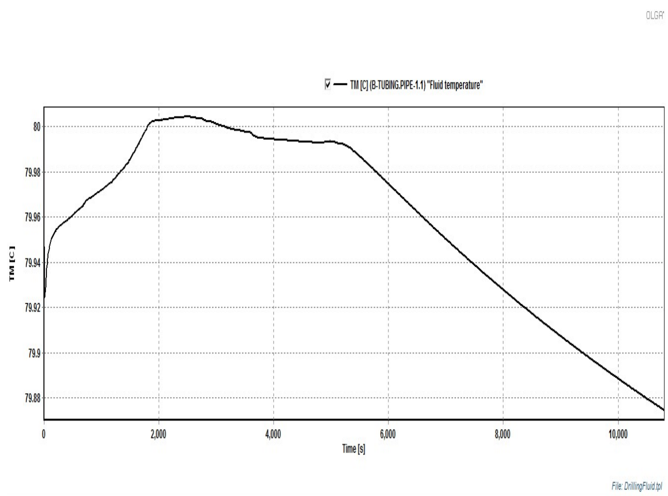

Figure 4: Trend Plot of the Tubing Fluid Temperature

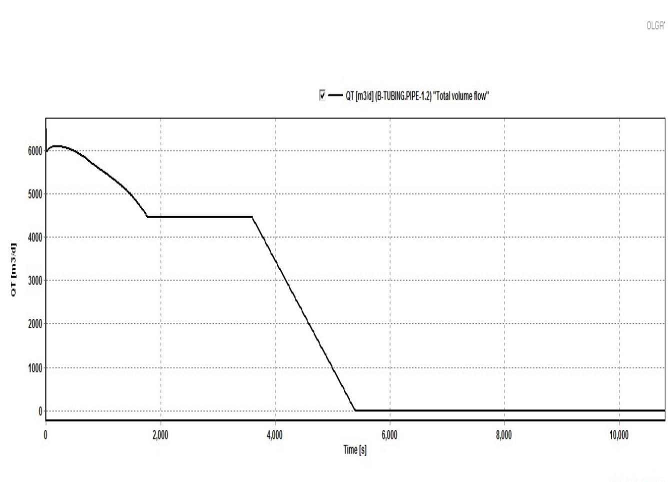

Figure 5: Trend plot of total volume flow

Fig. 5 shows that the total volumetric flow dropped from 6000 m^3/d at t = 0 sec to about 4500 m^3/d at t = 1800 secs. Just after this point, the volumetric flow remained the same and then experienced a sharp decline from 4500 m^3/d at t= 3700 secs to 0 m^3/d at t = 5200 secs. Beyond this point, there was no further increase or decrease of volumetric flow in the tubing system.

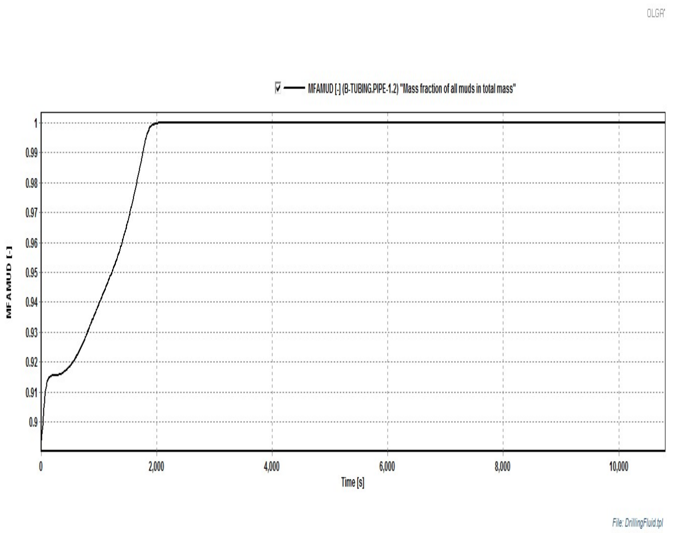

Figure 6: Profile Plot of the Mass (weight) of mud in the Tubing

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.

The effects of some of the parameters whose plots have been discussed and others such as tubing density of gas, total tubing density of liquid and tubing holdup on mud weight were modelled and their relationship correlated using MATLAB and validated using statistical technique. The steps and results are discussed in the next section.

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 2). The independent variables predicted the dependent variable and formed the mud weight correlation. The effects of the independent variables on the dependent variable were not the same as seen in equation 1. The data points were imported into MATLAB and a correlation equating the dependent variable with the independent variable using regress function in MATLAB.

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 x 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 x 10^{-4}, and the coefficient of the total tubing density of liquid is approximately 5.86 x 10^{-4}. Arranging these coefficients and putting them in the form of a linear regression equation 'Y=Ax_1+Bx_2+C' resulted to equation 1, which is the drilling mud weight correlation developed in this study.

$$\begin{aligned}\boldsymbol{Mud_{weight}} = {} & 3.072 + 0.273\, H_{ol} - 1.373\, x\, 10^{-5} L\,(m) \\ & - 0.0011\, P(bara) \\ & + 4.33\, x\, 10^{-4} ROG\, \left(\frac{kg}{m^3}\right) \\ & + 5.86\, x\, 10^{-4} ROL \left(\frac{kg}{m^{-3}}\right) \\ & - 0.0126\, T_m(^oC) \\ & + 3.662\, x\, 10^{-5} G_{T\left(\frac{kg}{s}\right)} \qquad (1)\end{aligned}$$

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

L is the tubing length,

G_T is total mass flow,

P is tubing pressure,

T is the tubing fluid temperature,

ROG is the tubing gas density

ROL is the tubing liquid density and

H_{ol} is the tubing hold up.

This correlation (equation 1) shows that the tubing holdup, densities of gas and liquid, and total mass flow have significant effects on the mud weight. Whereas the tubing length, the tubing fluid temperature and tubing pressure variables have insignificant effects on the tubing mud weight.

Table 2: OLGA Generated Variables Data Points

MUD_{weight}	G_T[kg/s]	LENGTH[m]	HOL	P_T-[bara]	ROG[kg/m3]	ROL B-[kg/m3]	T_M-[C]
0.893683	0	44.677795	0.712861	185.250397	270.689087	3048.193603	79.947319
0.893637	59.66304	134.033386	0.705512	178.026993	259.810486	3045.455627	79.823288
0.89359	59.097809	223.388977	0.697661	170.949402	249.050903	3043.219971	79.690582
0.893043	58.4338	335.256836	0.687391	163.733902	237.7211	3042.459839	79.537872
0.892992	57.46656	469.636963	0.677267	156.378204	226.1548	3041.78302	79.378197
0.892769	56.378262	664.328186	0.66242	146.680298	210.905106	3040.920288	79.132896
0.892671	54.625629	919.330444	0.6421	134.700699	192.086304	3040.726563	78.81926
0.892575	53.12672	1161.812744	0.619996	123.470001	174.578705	3042.603027	78.4916
0.892459	51.907669	1391.775024	0.596584	112.985298	158.195297	3044.409118	78.156342
0.892323	50.75272	1621.737427	0.570553	102.709602	142.165207	3046.414124	77.801651
0.892564	49.641151	1803.604126	0.545718	93.52256	128.508896	3050.113281	77.489403
0.892709	48.99469	1937.375366	0.521393	85.454033	116.4972	3053.371888	77.177422
0.895473	48.355469	2056.471924	0.503822	77.742462	104.983803	3056.557862	76.878906
0.895592	47.868301	2160.898682	0.475985	70.343063	93.912117	3059.591003	76.572227
0.895612	47.38723	2250.586182	0.45063	64.061821	85.097359	3063.581604	76.303902
0.895628	47.047829	2325.533936	0.428119	58.86208	77.921913	3067.215332	76.056152
0.895661	46.71777	2422.560547	0.39767	52.396778	68.9907	3071.790466	75.703568
0.895741	46.21941	2541.6604	0.357602	44.757301	58.407269	3077.181762	75.286072
0.895892	45.759361	2660.760498	0.314528	37.46838	48.282951	3082.360108	74.855453
0.9303	45.344528	2753.643799	0.413269	33.048409	42.308128	3089.721314	74.62529
0.930836	45.126808	2820.310547	0.40751	32.08625	41.086761	3093.0849	74.528618
0.931423	44.907902	2886.977051	0.401298	31.06568	39.7901	3096.640259	74.430588

Validation of the Correlation Using Statistical Technique

To confirm the statistical significance of equation (1), data analysis toolpak was used. From the summary output produced (see table 3 and 4), the values of R square, Significance F and P are assessed. The closer to 1 of the R Square value, the more reliable the correlation is. Also, the value of the Significance F must be less than 0.05 (Seref& Ahuja, 2008).

R Square for Tubing mud weight Correlation

Table 3: 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 3, R Square equals approximately 1, which represents aperfect 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.

Significance F value

To confirm if the result (the developed correlation) statistically significantly, the Significance F values is looked at. From table 4, the Significance F is approximately 2.71 x 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. Therefore, when trying to determine optimum parameters to maintain wellbore stability, equation 1 can reliably be used as a tool to for that. The equation would save drilling engineers a lot of time and cost during operations.

Table 4: 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			

Comparison of the Actual Mud Weight and Predicted Mud Weight

Also, in order to further validate this correlation for tubing mud weight estimation, the trend plot of both the actual data (from OLGA) and the predicted data (using the correlation) was done (Mudweighton the y=axis and the tubing length on the x-axis) (see fig. 7).

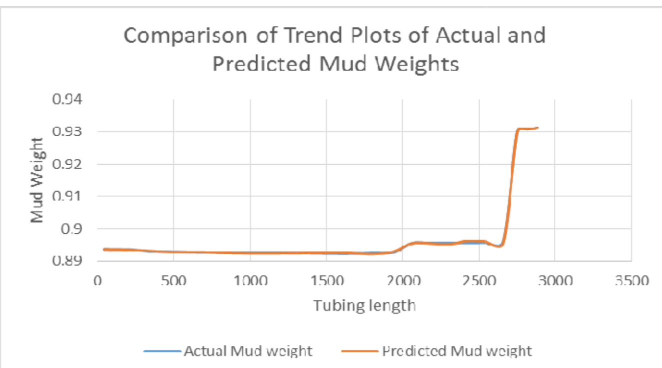

Figure 7: Trend plots of Actual and Predicted Mud Weights

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. The equation would save drilling engineers a lot of time and cost during operations.

VII. CONCLUSIONS

The drilling fluid systems utilized these days are highly engineered and losses of large fluid volumes contributes incremental expenses to the operation. Hence, a correlation or a predictive approach that has the capacity to reliably predict the optimum drilling fluid variables like fluid density for drilling operations is of huge significance. In this paper, investigation of 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 mud weight was carried out. The paper 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 less significant 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. Next step should be to further validate the correlation and the outcomes of this study using experimental data.

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