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Statistical Evaluation of Undulating Tortuosity on Liquid Accumulation in Gas Wells

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Abstract: Liquid accumulation has been known to occur in gas wells flowing under liquid loading regime. Previous solutions have been provided that considered flow parameters such as gas velocity, flow rate and surface tension, but this work considered the impact of the tortuosity of the wellbore path. Tortuosity of the wellbore is basically the measure of deviation of the wellbore from a straight path. Data was obtained from literatures and from the industry. Introducing critical assumptions of a truly vertical well and using Microsoft Excel, two regression models were developed that showed a linear relationship between the true vertical depths and gas liquid ratio which was used to measure the accumulation of liquids in the wellbore. This linear relationship can be explained as the action of gravity on coproduced liquids. This is because for wells flowing under the liquid loading regime, the velocity of the gas is below critical thus, coproduced liquids fall back under the action of gravity. The First model was preferred because it had a root mean square error value that was significantly less than the other. This result proves that for wells under the liquid loading regime, liquid accumulation increases with depth and solutions to lift liquids would be more effective at points closer to the well bore. Also, using this model, production engineers can spot the point liquid removal methods such as ESP can be applied. Further studies on this subject matter that introduces the dogleg severity at known depth and removes the critical assumption of a truly vertical well should be able to develop a model that shows the depths at which the velocity of the gas is below critical.

Keywords: Tortuosity, Liquid Loading, Gas well, True Vertical Depth, Velocity

Introduction

The natural gas industry has evolved over the years to be one of the fastest growing industries in the energy space due to increasing demand for cleaner and more efficient sources of energy. Natural gas having a lower carbon footprint than other fossil fuel sources, is considered to be a cleaner source of energy. According to the Energy Information Administration (EIA), natural gas will be the second source of worldwide energy consumption by 2040 with a 1.4% annual growth rate from 2015.

With supply and distribution expected to increase in order to meet growing demand, it is necessary that a better solution to one of the most obvious challenges in the production of natural gas is proffered. One obvious problem is the accumulation of liquids in gas wells. Liquid accumulation is a condition in a gas well in which coproduced liquid lacks sufficient velocity to flow out of the wellbore. The liquid accumulated creates a hydrostatic pressure in the well against the reservoir formation pressure which causes the reservoir to experience back pressure leading to a decline in production rate. The lower the gas rate falls; more liquid will be accumulated creating a liquid holdup cycle which will cause the well to cease production eventually.

As a result of liquid accumulation, only 25% to 30% of the potential of gas wells are produced under natural flow before a decline in production occurs (Alison and Bill, 2008). The accumulated liquid causes low productivity, intermittent shut-ins, high operating costs, early abandonment and possible killing of the well (Joseph and Ajienka, 2013). The presence of liquid phase in a gas well is due to the following as noted by (Binli, 2009):Condensation of water vapor dissolved in the gas due to a drop in pressure and temperature below dew point as the solution flows through the production string, Condensation of hydrocarbons as gas solution flows to the surface when or if conditions drop below dew point, Production of water from another zone especially in open-hole completions and some cases of wells with multiple perforations, Water coning or water cresting in wells with high production rate and water encroachment if the reservoir has a water drive mechanism.

Given the effect of accumulated liquid on gas production, some correlations (Turner et al.,1969; Coleman et al., 1991; Nossier et al., 2000; Li et al., 2001; and Veeken et al., 2003) modelling flow conditions based on the velocity and flow rate of the gas have been developed. Although wellbore trajectory affects the production performance of gas wells (Jackson et al., 2011), little work has been done to model liquid accumulation based on the tortuosity and curvature of the wellbore.

Generally, tortuosity is defined as the summation of the total curvature, including build and walk, to the survey stations length (Samuel et al., 2005). Since there exists no industry standard for the quantification of tortuosity, it is usually expressed in degrees/100ft similar to the expression for the dogleg severity. Understanding the relationship between tortuosity and liquid accumulation is essential to solving the gas production problem.

Problem Definition

Liquid accumulation is a common problem in maturing gas fields. In the US it is estimated that 90% of producing gas wells are operating in liquid loading regime (Park 2008). The accumulation of liquid causes low productivity, intermittent shut-ins, high operating costs, early abandonment and possible killing of the well (Joseph et al., 2013). The use of models to predict and evaluate the occurrence of liquid accumulation has enabled gas producing companies to act proactively in curbing the early occurrence of liquid loading. These models are largely based on the gas velocity and flowrate. But wellbore trajectory affects the production performance of gas wells significantly (Jackson et al., 2011), hence, modelling the accumulation of liquids in gas wells based on the undulation tortuosity of the wellbore would enable a more robust understanding and help in proffering better solutions to curb the liquid accumulation problem.

Literature Review

Liquid accumulation is a common gas production problem that causes decreased production rate, intermittent shut-ins, increase in operating costs, early abandonment and possible killing of the well in severe cases. The process of accumulation of liquid in a gas well is referred to as liquid loading (Zhou and Yuan, 2010). Liquid loading occurs when produced gas lacks sufficient velocity to remove coproduced liquids from the wellbore. Liquids can accumulate in gas wells having prolific reservoirs with a high gas-liquid ratio as well as in low permeability gas reservoirs. As a result of the accumulation of liquids, gas wells are expected to produce only 25% to 30% of their potential under natural flow before a decline in production (Alison et al., 2008). For low-pressure reservoirs, upon initiation of liquid loading, the well could kill itself within a few days when the bottom hole flowing pressure is less than the backpressure exerted by the liquid. (Riza et al., 2016).

In describing the onset of liquid accumulation, four basic flow patterns or regimes have been used.

These flow regimes in order of decreasing gas velocities include (Lea et al., 2008):

- Mist flow: In this flow pattern, the continuous phase is gas and the liquid is entrained in the gas as a mist. The wall of the tubing is coated with a thin film of liquid, but the pressure gradient is mostly determined by the gas flow.
- Churn/Transition flow: This flow regime is characterized by chaotic or erratic production. The liquid remains significant but the pressure gradient is dominated by gas. The liquid may be entrained as droplets in the gas and the continuous phase changes from gas to liquid as the velocity of the gas decreases.
- Slug flow: At this stage of flow, the continuous phase becomes liquid and the gas bubbles expand as they rise into larger bubbles forming slugs. The pressure gradient is significantly affected by both the gas and liquid.
- Bubble flow: This stage is characterized by liquid filling the tubing and gas exist as small bubbles rising in the liquid. The bubbles cause a reduction in the density of the liquid.

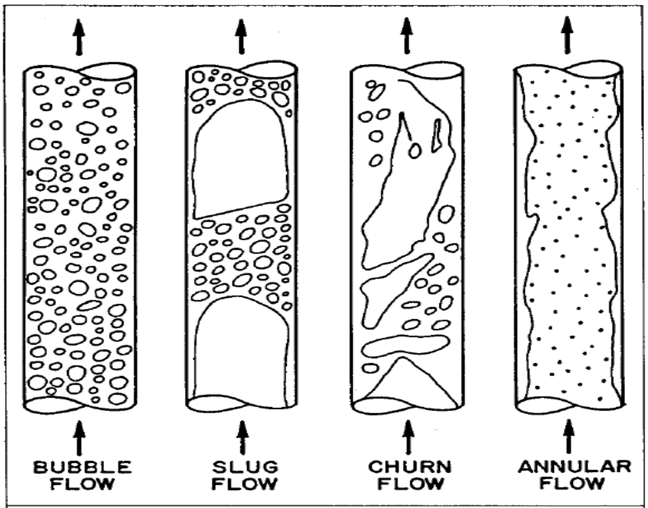

Fig. 1—Flow patterns for upward vertical flow.

Figure 1: Multiphase flow patterns for vertical flow (Brill, 1987)

The transition from mist flow to churn flow triggers liquid accumulation (Falcone and Barbosa Jr, 2013).

Existing Models

Various authors have made successful attempts at modelling liquid accumulation in gas wells. These models present parameters like gas velocity, drag coefficient and flow rate that follow flow reversal mechanisms and droplet removal theories.

Droplet Removal Theory

The first model based on the droplet removal theory was developed by Turner et al., (1969). Turner et al. introduced the continuous film model and the entrained drop movement model but after testing these models from field data they concluded that the entrained droplet modelbetter predicted the onset of liquid loading. The droplet model developed by Turner et al. was based on Newton’s law and the critical Weber number model developed by Hinze (1955). They proposed that a free-falling particle in a fluid medium will reach a terminal velocity when the accelerating (gravitational) force pulling the particle downwards equals the drag forces acting in opposite direction. Fig 2 schematically shows the free body diagram of a liquid droplet with the drag and gravitational forces acting on it. The authors tested their model with field data and proposed a 20% adjustment after considering wells with lower flow rates. This readjusted model is considered to be the most widely used due to its simplicity.

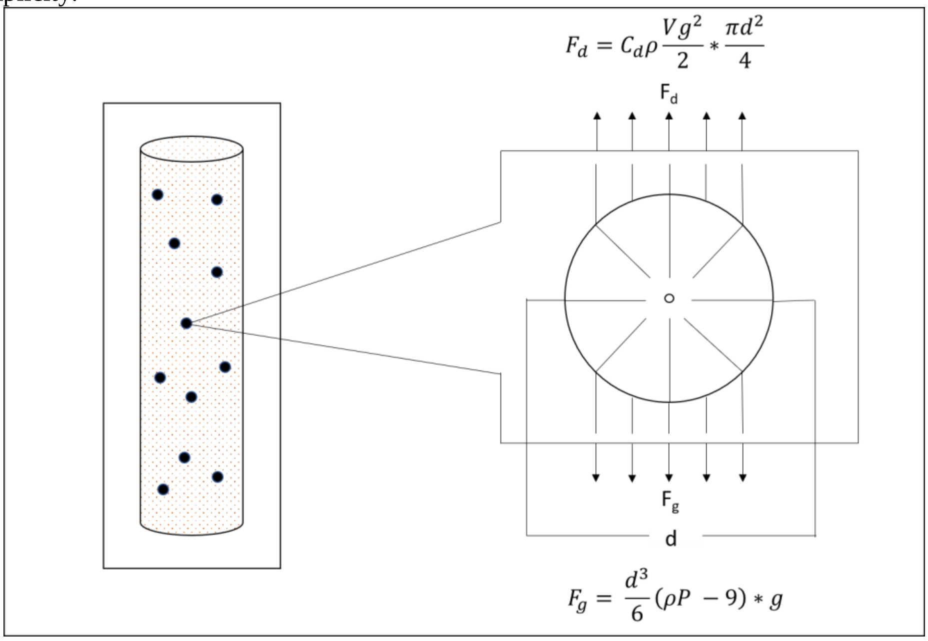

Figure 2: Drag and gravitational forces acting on a liquid droplet in a gas stream (Adapted from Turner et al 1969)

Coleman et al (1991) tested the model developed by Turner et al with data from a large number of low-pressure wells and claimed that the 20% adjustment is unnecessary for wells operating below 500psi. Subsequently, Nossier et al. (2000) developed two models accounting for transition flow regime and highly turbulent flow regime. Their model was aimed at solving the discrepancies that were associated with the Turner et al. model when tested with different sets of actual data. They explained that the discrepancy was because Turner et al did not consider the impact of different flow regimes in the development of their model. On the other hand, Li et al. (2001), considered the liquid droplet to deform under the drag force and attain a flat shape instead of a spherical one as proposed by Turner et al. They claimed that the spherical droplets have a small efficient area held by gas and require higher critical flow rate and terminal velocity to lift fluids to the wellhead.

Belfroid et al., (2008) presented a corrected model of Turner’s equation after applying the model developed by Fiedler and Auracher (2004) and experimental studies made on inclined pipes. They established that the onset of liquid loading is determined by the transport of the liquid film. Their results showed that the liquid loading velocity could be predicted within a 20% error for different well conditions using the angle-dependent Turner criterion they developed. Meanwhile, Zhou and Yuan (2010) evaluated the Turner et al., model for its discrepancies and concluded that the liquid droplet concentration and amalgamation is the third mechanism that contributes to liquid loading. They found their model to be more accurate than Turner et al’s model in predicting the occurrence of liquid loading using the data provided by Turner et al., it also had similar results with that of Coleman et al's model.

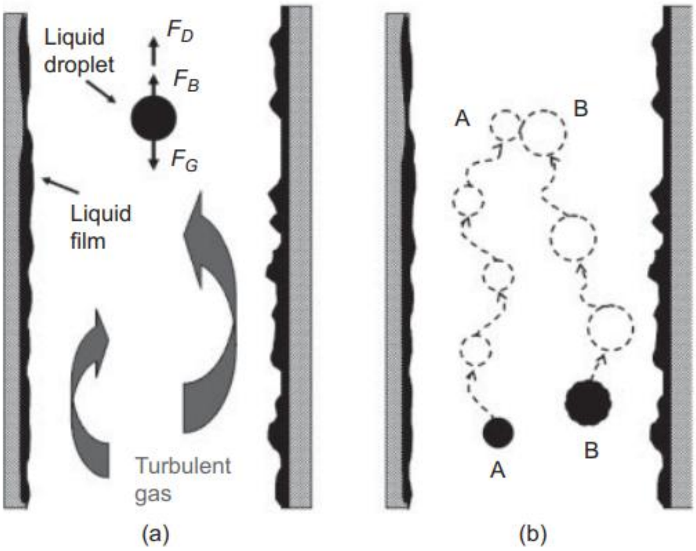

Fig.3: Amalgamation of liquid droplets as presented by Zhou and Yuan (2010).

Wang et al., (2015) developed a new entrained model taking into consideration the maximum drop size difference and the deformation of the liquid drop on the minimum gas flow rate.

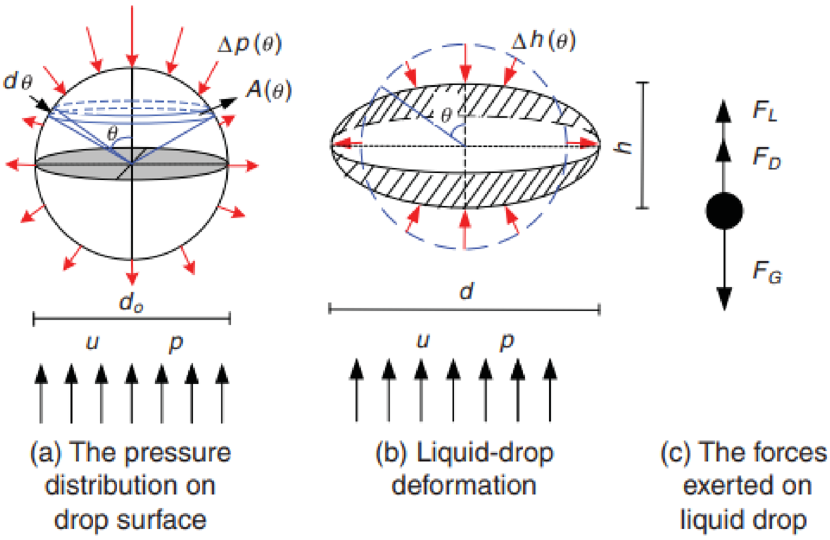

Fig4: Free body diagram of liquid drop deformation presented by Wang et al (2015).

Film Flow Reversal Theory

One of the earliest models of film flow reversal was developed by Barnea (1986). He incorporated the effect of inclination and interfacial shear stress on liquid loading. However, he assumed that the pipe had a uniform thickness and liquid flow occurred as an annular film. The model developed by Barnea (1986) was for annular to slug transition boundary. Barnea (1987) presented a comprehensive and unified model that applied a transition mechanism for an entire range of pipe inclinations.

To solve the problems created by Barnea's assumption, Luo et al (2014) developed their correlation by considering the maximum thickness of the liquid film as a factor for critical gas velocity. Although their proposed model outperforms Turner et al's droplet model and Barnea (1986) and Barnea (1987) model it cannot predict correctly the occurrence of liquid loading in deviated wells because of the assumption that the thickness of the liquid film is constant for all angles of deviation.

Veeken et al (2009) modelled the liquid loading process of vertical wells using OLGA a transient multiphase flow numerical simulator that uses a modified version of Gray outflow correlation. His findings suggest that liquid loading occurs due to the liquid-film reversal theory. They presented a modified Turner et al's expression for the prediction of the onset of liquid loading.

Wang et al. (2017) presented a correlation that predicts the critical gas velocity of horizontal wells with a 95% accuracy. Their correlation takes into account the effect of the tubing diameter, the velocity of the liquid and flowing temperature and pressure on the critical gas velocity. Wang et al's new correlation was based on a new analytical model which shows that the liquid loading status of gas wells can be determined by comparing the critical gas rate with the production rate of the well. Meanwhile, Fan et al. (2018) performed an experimental study to determine the cause of liquid loading in inclined pipes and offered a new methodology that depends on the velocity profile. They concluded that the main source of liquid accumulation especially for inclined pipes is the liquid film reversal. They also stated that in an upward inclined pipe, liquid accumulation takes place when the amount of momentum transfer from the gas phase to the liquid film is not enough to overcome the opposing forces of gravity and wall friction. Their experiment was focused on low-liquid-loading conditions and showed that for inclination angles lower than 30° the critical gas velocity increases with inclination angles. For larger angles, the effect of the liquid flow rate is quite evident on the critical gas velocity.

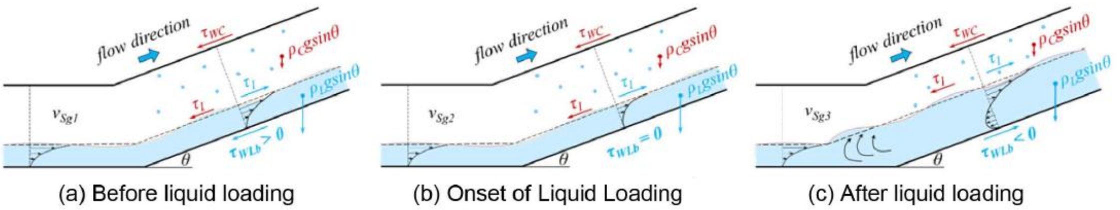

Fig 5 The onset of liquid film reversal at pipe bottom (Fan et al. 2018)

Rastogi and Fan (2019) developed a new model for predicting the critical gas velocity necessary to unload accumulated liquids in large diameter pipes. Their work was based on the liquid film reversal at the pipe bottom. They concluded that the critical gas velocity corresponds to a zero liquid wall shear stress at the pipe bottom.Vieira and Stanko (2019) affirmed that for inclined wells, the droplet model underestimates the critical gas velocity after performing an exhaustive experiment and comparing their experimental results with existing droplet and liquid-film models. Subsequently, Pagou and Wu (2020) developed a model based on the momentum balance equation. Their model was based on the liquid-film reversal theory and they assumed that the change of flow regime from annular to slug or churn flow is responsible for the onset of liquid loading.

Methodology

The data used for this study were sourced from already published work and from professionals in the oil and gas sector. Production data and drilling data was gotten and two parameters were used in this study, they include:

1. True Vertical Depth (TVD): This is the vertical distance of the wellbore calculated from the surface usually the rotary kelly bushing (RKB) to the bottom of the wellbore. This parameter was selected instead of Dogleg Severity because of the limitation of insufficient data encountered during this research. The TVD was selected based on the assumption that the dogleg severity at different depths was zero. The TVD is measured in feet.
2. Gas Liquid Rate (GLR): This is a measure of the coproduced liquid (water and oil). The GLR is measured in barrels of oil per day (BOPD).

Using Microsoft Excel analysis toolpak, correlation and regression analysis were performed on the data obtained. The research process is explained in detail below.

Modelling:

Step 1: Highlight the cells containing the data set. The first column or row to be highlighted represents the x axis while the second column or row represents the y axis.
Step 2: Select the insert tab and go to the chart group.
Step 3: In the chart group select the menu at the bottom right. A window should open.
Step 4: Select the first chart under the recommended chart section. A chart will appear in the excel environment.
Step 5: To get the graphical model, right click on the plots and select add trendline. A side window should appear at the right-hand side of the screen.

Step 5: Select set intercept, display equation on chart, Display R-squared value on chart and select linear under trendline options.

Statistical Analysis:

Step 1: Launch the Microsoft application

Step 2: Go to the data analysis tab to check if the data analysis toolpak has been added Data analysis will be seen under the analyze group if it has been added. If it has been added move on to step five else, continue to step three.

Step 3: Open the file tab and click on options. A window should open then click on Add-ins.

Step 4: select analysis toolpak then click on manage. A small window should open then select analysis toolpak, click ok.

Step5: Launch data analysis by clicking data analysis in the data tab under the analysis group.

Step 6: To perform correlation select correlation in the drop-down menu then click ok.

Step 7: Select the input range and set the output range to new worksheet ply then click ok.

Step 8: The correlation analysis will be seen in a new worksheet.

Step 9: To perform regression select regression in the drop-down menu then click ok.

Step 10: Select the range for the input Y and input X, residuals, standardized residuals, residual plots, line fit plots and normal probability plots then click ok.

Step 11: The regression analysis will be seen in a new worksheet.

Error Analysis:

Step 1: In cell K3, L3, M3 and N3 type the header titles; observed value, predicted value, difference and RMSE respectively.

Step 2: copy the range of observed values (GLR) and paste in cell K4.

Step 3: copy the range of predicted values (this can be seen in the regression analysis) and paste in cell L4.

Step 4: To calculate the difference, type in cell M4; =K4-L4. This would produce the difference for the first cell.

Step 5: To populate the other cells, hover your mouse pointer on the bottom right of cell M4, this should produce a pointer (Fill cursor) with the shape of a plus sign.

Step 6: Click, hold and drag down to the number of cells.

Step 7: To calculate the RMSE value, type in cell N4, =SQRT(SUMSQ(M4:M35)/COUNTA(M4:M35)). This formular should generate the root mean square error value assuming a total data set of 31.

Results and Discussion

Two models were obtained after plotting the gas liquid ratio (GLR) against the true vertical depth (TVD) from the two data sets. The models obtained for well 1 and well 2 are given below:

Well 1:

$$GLR = 0.037TVD \qquad (1)$$

Where; TVD = True Vertical Depth measured in feet (ft)

GLR = Gas Liquid Ratio measured in barrels of oil per day (bopd)

Well 2:

$$GLR = 0.0188TVD + 19.858 \qquad (2)$$

Where; TVD = True Vertical Depth measured in feet (ft)

GLR = Gas Liquid Ratio measured in barrels of oil per day (bopd)

The plots for well 1 and well 2 are also given below:

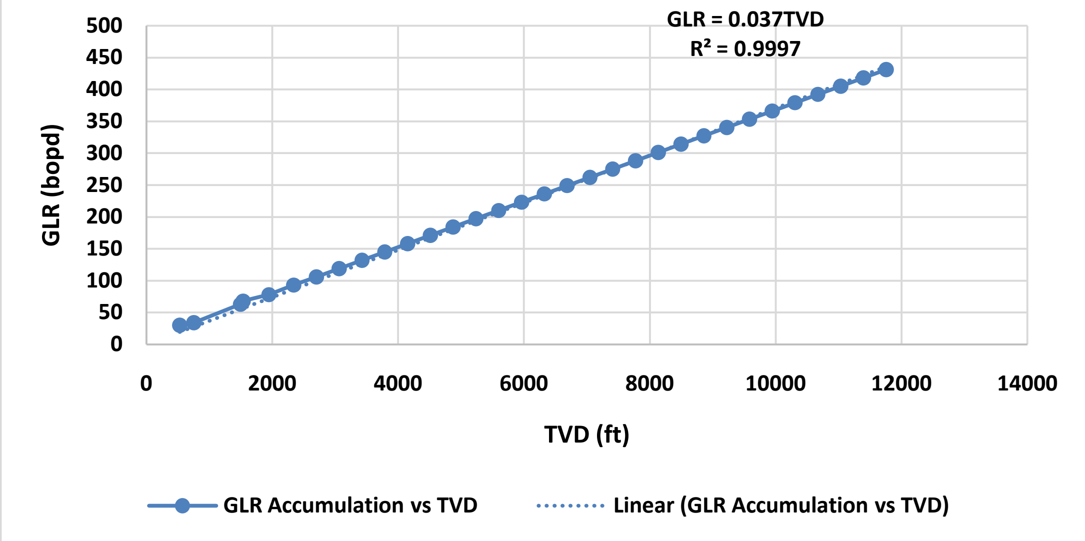

Figure6: A Plot showing the plot of Gas Liquid Ratio (GLR) versus True Vertical Depth (TVD) for well 1

Fig 6 shows a linear relationship with an R^2 value of 0.9997 indicating a near perfect correlation between the GLR and TVD for well 1.

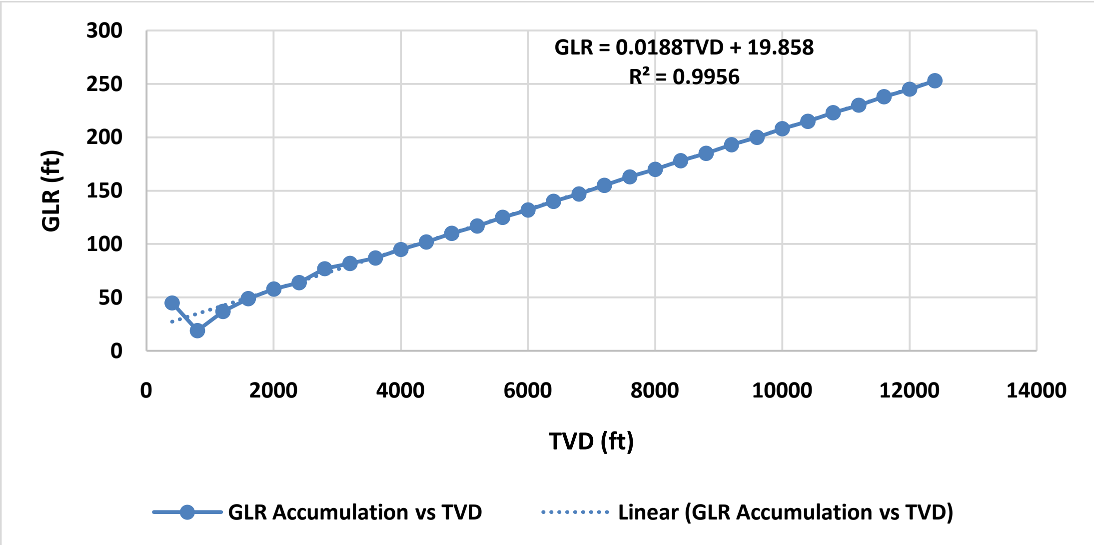

Figure 7: A Plot showing the plot of Gas Liquid Ratio Accumulation (GLR) versus True Vertical Depth (TVD) for well 2.

Fig 7 shows a linear relationship between the GLR and TVD with an R^2 value of 0.9956 implying a near perfect correlation between the GLR and TVD for well 2.

Fig 6 and Fig 7 implies that the amount of coproduced liquid accumulated in a gas well will increase as depth increases. This makes sense because as the gas velocity reduces below the critical velocity, the coproduced liquid falls under the action of gravity and more liquids will tend to accumulate more as depth increases.

Correlation and Regression

The result from the correlation analysis performed showed a near perfect correlation of GLR to TVD with an R^2 value of 0.999976 for well 1 and 0.997788 for well 2. This implies that coproduced liquid in a gas well will accumulate as depth increases.

The statistical regression for well 1 is given in table 3.

Table 3 Regression statistics for well 1.

Regression Statistics	
Multiple R	0.999975994
R Square	0.999951988
Adjusted R Square	0.999950387
Standard Error	0.858124261
Observations	32

The multiple R value of 0.99 (approximately 1) shows a strong linear relationship between GLR and TVD. The R square of 0.99 (99%) shows that 99% of the values fit the model.The statistical regression for well 2 is given in table 4.

Table 4 Regression statistics for well 2

Regression Statistics	
Multiple R	0.99778756
R Square	0.995580016
Adjusted R Square	0.995427602
Standard Error	4.629210346
Observations	31

The multiple R value of 0.997 (approximately 1) shows a strong linear relationship between GLR and TVD. The R square of 0.995 (99.5%) shows that 99% of the values fit the model.

Table 5 ANOVA for well 1.

ANOVA					
	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	460095.6274	460095.6274	624809.6741	2.39917E-66
Residual	30	22.0913174	0.736377247		
Total	31	460117.7188			

From table 5, the ANOVA for well 1 shows a regression SS of 460095.6274 and a total SS value of 460117.7188 indicating that the regression model explains about 99.9% of all the variability in the data set.

Table 6 ANOVA for well 2.

ANOVA					
	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	139980.4129	139980.4129	6532.109254	1.06291E-35
Residual	29	621.4580645	21.42958843		
Total	30	140601.871			

From table 6, the ANOVA for well 2 shows a regression SS of 139980.4129 and a total SS value of 140601.871 indicating that the regression model explains about 99.5% of all the variability in the data set. Also, the p value of the independent variable (TVD) for well 1 and well 2 is $2.39916777696393 \times 10^{-66}$ and $1.83695675528468 \times 10^{-12}$ respectively. Since the p values for both wells is below 0.05 it indicates a 95% confidence that the slope of the regression line is not zero and hence there is a significant linear relationship between the dependent (GLR) and independent (TVD) variable.

Table 7 Residual output for well 1

RESIDUAL OUTPUT			
Observation	*Predicted Gas Liquid Rate*	*Residuals*	*Standard Residuals*
1	28.34664058	1.653359418	1.95856195
2	36.34953573	-2.349535732	-2.783249203
3	63.05333701	-0.053337012	-0.063182778
4	64.53604505	3.463954946	4.103385069
5	79.17957942	-1.179579417	-1.397324343

6	93.24874366	-0.248743657	-0.29466059
7	106.2339824	-0.233982357	-0.277174422
8	119.2192211	-0.219221056	-0.259688253
9	132.2044598	-0.204459755	-0.242202084
10	145.1896985	-0.189698455	-0.224715915
11	158.1749372	-0.174937154	-0.207229746
12	171.1601759	-0.160175853	-0.189743578
13	184.1454146	-0.145414552	-0.172257409
14	197.1306533	-0.130653252	-0.15477124
15	210.115892	-0.115891951	-0.137285071
16	223.1011307	-0.10113065	-0.119798902
17	236.0863693	-0.08636935	-0.102312734
18	249.071608	-0.071608049	-0.084826565
19	262.0568467	-0.056846748	-0.067340396
20	275.0420854	-0.042085448	-0.049854227
21	288.0273241	-0.027324147	-0.032368059
22	301.0125628	-0.012562846	-0.01488189
23	313.9978015	0.002198455	0.002604279
24	326.9830402	0.016959755	0.020090448
25	339.9682789	0.031721056	0.037576617
26	352.9535176	0.046482357	0.055062785
27	365.9387563	0.061243657	0.072548954
28	378.923995	0.076004958	0.090035123
29	391.9092337	0.090766259	0.107521292
30	404.8944724	0.105527559	0.125007461
31	417.8797111	0.12028886	0.142493629
32	430.8649498	0.135050161	0.159979798

From the table 7, the residual plot was obtained as shown in fig 8.The scatter plot shows the linearity of the parameters under study since most of the plots are arranged on the TVD axis.

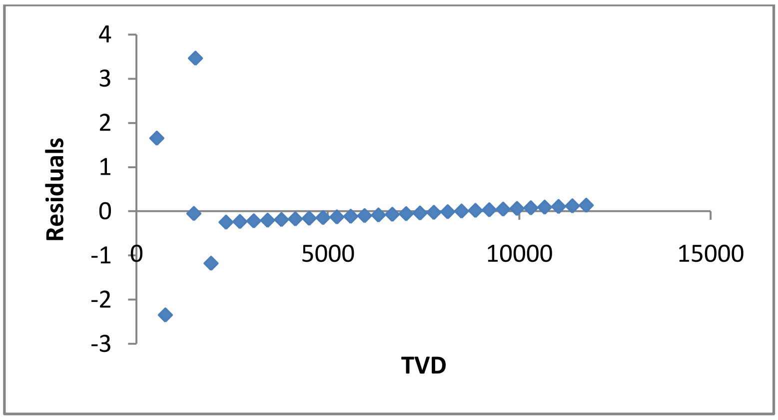

Fig 8 A chart showing the plot of the Residuals Against TVD for well 1

Table 8 Residual output for well 2

RESIDUAL OUTPUT			
Observation	***Predicted GLR***	***Residuals***	***Standard Residuals***
1	27.37096774	17.62903226	3.873318282
2	34.88387097	-15.88387097	-3.489884579
3	42.39677419	-5.396774194	-1.185738607
4	49.90967742	-0.909677419	-0.199867476
5	57.42258065	0.577419355	0.126866235
6	64.93548387	-0.935483871	-0.205537475

7	72.4483871	4.551612903	1.000046129
8	79.96129032	2.038709677	0.447929946
9	87.47419355	-0.474193548	-0.104186237
10	94.98709677	0.012903226	0.002835
11	102.5	-0.5	-0.109856237
12	110.0129032	-0.012903226	-0.002835
13	117.5258065	-0.525806452	-0.115526236
14	125.0387097	-0.038709677	-0.008504999
15	132.5516129	-0.551612903	-0.121196235
16	140.0645161	-0.064516129	-0.014174998
17	147.5774194	-0.577419355	-0.126866235
18	155.0903226	-0.090322581	-0.019844998
19	162.6032258	0.396774194	0.087176239
20	170.116129	-0.116129032	-0.025514997
21	177.6290323	0.370967742	0.08150624
22	185.1419355	-0.141935484	-0.031184996
23	192.6548387	0.34516129	0.075836241
24	200.1677419	-0.167741935	-0.036854996
25	207.6806452	0.319354839	0.070166242
26	215.1935484	-0.193548387	-0.042524995
27	222.7064516	0.293548387	0.064496242
28	230.2193548	-0.219354839	-0.048194994
29	237.7322581	0.267741935	0.058826243
30	245.2451613	-0.24516129	-0.053864993
31	252.7580645	0.241935484	0.053156244

From table 8, a TVD residual plot was obtainedas shown in fig 9. The scatter plot shows the linearity of the parameters under study since most of the plots are arranged on the TVD axis.

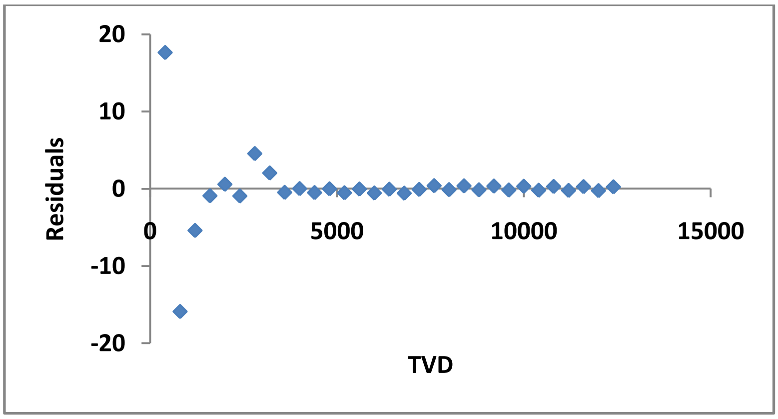

Fig 9 A chart showing the plot of the Residuals Against TVD for well 2

Table 9 Observed GLR values and predicted GLR values for Well 1

Observed GLR Values (BOPD)	Predicted GLR Values (BOPD)
30	28.34664058
34	36.34953573
63	63.05333701
68	64.53604505
78	79.17957942
93	93.24874366
106	106.2339824
119	119.2192211
132	132.2044598
145	145.1896985
158	158.1749372

171	171.1601759
184	184.1454146
197	197.1306533
210	210.115892
223	223.1011307
236	236.0863693
249	249.071608
262	262.0568467
275	275.0420854
288	288.0273241
301	301.0125628
314	313.9978015
327	326.9830402
340	339.9682789
353	352.9535176
366	365.9387563
379	378.923995
392	391.9092337
405	404.8944724
418	417.8797111
431	430.8649498

Table 9 shows the predicted values for well 1 obtained from regression analysis and a chart showing the plot of predicted against observed values is givenin fig 10.

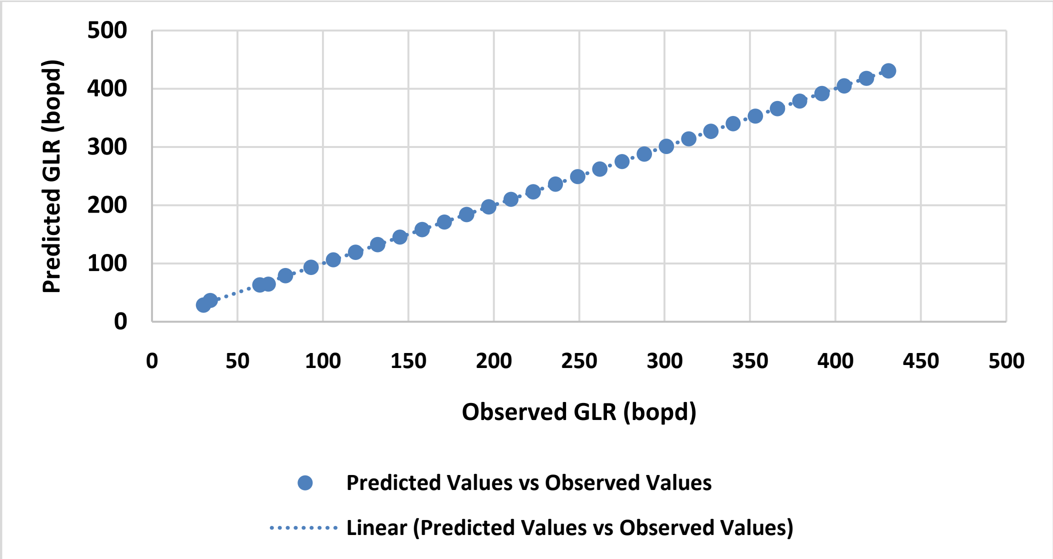

Fig 10 A chart showing the plot of Predicted GLR Against Observed GLR for well 1

In Fig 10, The plot shows minimum deviation from the regression line implying that the observed values are close to the predicted values. This means that the random disturbance in the relationship between the independent variable (TVD) and the dependent variable (GLR) is the same across all values of the independent variable and the standard errors of the regression coefficients for well 1 is reliable.

Table 10 Observed GLR values and predicted GLR values for Well 2

Observed GLR value (BOPD)	Predicted GLR value (BOPD)
45	27.37096774
19	34.88387097
37	42.39677419
49	49.90967742
58	57.42258065
64	64.93548387

77	72.4483871
82	79.96129032
87	87.47419355
95	94.98709677
102	102.5
110	110.0129032
117	117.5258065
125	125.0387097
132	132.5516129
140	140.0645161
147	147.5774194
155	155.0903226
163	162.6032258
170	170.116129
178	177.6290323
185	185.1419355
193	192.6548387
200	200.1677419
208	207.6806452
215	215.1935484
223	222.7064516
230	230.2193548
238	237.7322581
245	245.2451613
253	252.7580645

Table 10 shows the predicted values of well 2 obtained from regression analysis which were used in obtaining the plot shown in Fig 11

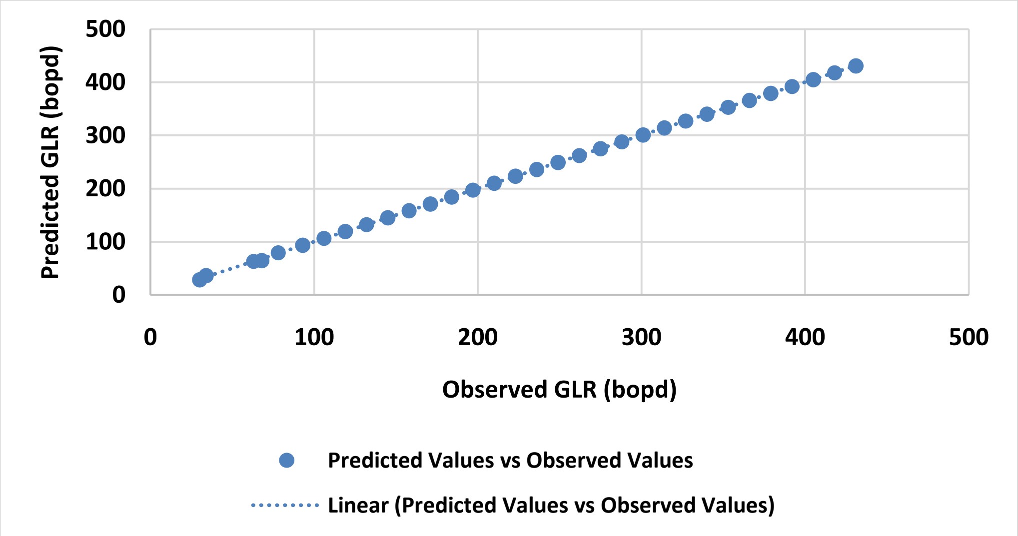

Fig 11 A chart showing the plot of Predicted GLR Against Observed GLR for well 2

In Fig 11, The plot shows minimum deviation from the regression line implying that the observed values are close to the predicted values.

Error Analysis

The error analysis was done using the predicted values in Table 9 and Table 10. The Root Mean Square Error (RMSE) value gotten from the analysis were 0.843822 and 4.477391 for well 1 and well 2 respectively. This indicates that well 1 fit the generated model better than well 2 and the model for well 1 is preferrable.

Table 11RMSE values for well 1 and well 2

RMSE for Well 1	0.843822
RMSE for Well 2	4.477391

Conclusion

This study focused on statistically finding and modelling the relationship between tortuosity and liquid loading. At the end of this study two statistical models were developed and the relationship between true vertical depth and gas liquid rate of accumulation was established. Though our parameter of measurement for tortuosity was dogleg severity, due to difficulty in assessing related data, critical assumptions were made and the relationships between TVD and GLR was developed. The conclusion of this study can be summed in the following:

From the result of our analysis, it is clear that there is a strong linear relationship between TVD and GLR as seen from the plots obtained in Fig 6 and Fig 7. Implying that the deeper we go downhole the more liquid is accumulated. I believe this is logical because for a well in the liquid loading regime, the velocity of the gas is below critical and thus, the coproduced liquid falls back into the wellbore under gravity. So, the amount of liquid accumulated will be greater as we travel down the wellbore path.

The two models had a multiple R value of over 99% indicating that there is a near perfect correlation between the GLR and the TVD for the two models.

The two models showed homogeneity of variance (homoscedasticity). Implying that the difference between the observed values and the predicted values is very minimal and the standard error of the regression coefficients are reliable. The p-values of the two models were below 0.05 indicating 95% confidence that the slope is non-zero and there exists a significant linear relationship between GLR and TVD. It is safe to assume that since the dogleg severity was taken to be zero the volume of liquid accumulated at different depths will increase as the dogleg increases. Although, the proportion to which it will increase can be the subject of further research.

More so, the model developed from data gotten from well 2 fit better than that of well 1 because the error value of well 1 was significantly lower than that of well 2 with a root mean square error difference of approximately 3.6.

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