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# The Effect of Viscosity on Tubing Performance: A Case Study of Well_XX in the Niger Delta, Nigeria

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***Abstract:***
*One of the parameters used to determine Reynolds numbers is viscosity and is the value of the Reynolds number that indicates if the flow is laminar, transition or turbulent flow. High viscosity oil and conventional oil require different amount of gas rate to lift them from the well heavy oil consume up to 3-5 volume above low vicious oil. Friction factor and the liquid holdup are gotten from the value of viscosity. Pressure gradient and liquid holdup depends on flow pattern so accurate prediction of flow pattern is very important. Increase in liquid viscosities result in lower intermittent region. The existing Mechanistic model were developed and validated with low viscous crude between 10cp and 110cp as such they are not able to predict pressure drop for high vicious crude of viscosity above 100cp to 500cp accurately as these model underestimate Pressure drop. The dynamics of slug flow and the film flow zone were the basis that characterizes the Hydrodynamic model developed and the film in the slug unit is used as the control volume. Duns and Ros (1964) Model was used to validate the model with Field Data. The poor prediction of pressure gradient by model is as a result of not identifying the right flow pattern as each model is flow pattern dependent.*

***Keywords:*** *Film flow zone, flow pattern, laminar flow, liquid holdup, mechanistic model, pressure drop, production optimization, Reynolds number, slug flow zone, transition flow, turbulent flow, viscosity*

## 1. Introduction

In the design of wells different section of the production system are usually modeled. The wellbore Sandface, reservoir, produced fluids, production equipment on surface and down hole. Several methods are being used for production optimization.

Well performance depends on reservoir deliverability and reservoir deliverability depends on reservoir pressure, pay zone, thickness and permeability .reservoir boundary type and distance, wellbore radius, reservoir fluid properties, near wellbore condition, reservoir relative permeability. Oil production from well is operated at constant bottom hole pressure as a result of the constant well head pressure impose by the constant choke size.

As oil is produce from wellbore the fluid properties changes and other parameter that govern flow also changes. These changes are normally declining reservoir pressure, increasing water cut and Gas – Liquid Ratio which will reduce flow rates. Decreasing reservoir pressure increases oil viscosity as below bubble point the gas in solution in the oil is release and the oil shrinks and this cause more resistance to flow of oil in the wellbore

Mechanistic model develop are based on low viscous oil between ( 10cp and 110cp ) that will not adequately account for Heavy oil and extra heavy oil .bitumen and oil sand which account for 70% of oil resources worldwide. The heavy oil produce in the range (0.1-10 Pa's) produce possess a challenge as the conventional Artificial Lift system are modified ( Dewan and Elfarr 1981; Szucs and Lim 2005) high viscosity oil require 3-5 times more lifting gas flow rate than conventional oils. Mechanistic model develop for low viscosity liquid may not adequately account for effect of high viscosity oil on the performance of gas lift (Schmidt et al. 1984), the effect on the Taylor bubble behaviors (White and Beardmore 196 2) , slug length and the drift velocity (Gokcal et al. 2009; Sakharov and Mokhov, 2004). Sakharov and Mokhov (2004) in their experiment with high viscosity oil observed a new positive frictional pressure difference.

Adequate knowledge of this trend of High viscosity oil will aid in getting the optimum design of wells. The proper selection, design, and installation of tubing string are critical parts of any well completion. Tubing strings must be sized correctly to enable the fluids to flow efficiently or to permit installation of effective artificial lift equipment. The optimum tubing size is selected to obtain the desired production rates at the lowest capital and operating costs. This usually means at the maximum initial flow rate and maintaining it as long as possible. Whatever the case, the selection process inevitably involves analysis of the gross fluid deliverability and flow stability under changing reservoir conditions to confirm that the production forecast can be met.

A tubing string that is too small causes large friction losses and limits production. It also may severely restrict the type and size of artificial lift equipment. A tubing string that is too large may cause heading and unstable flow, which results in loading up of the well and can complicate work-over operations.

The objective of this study is to develop a viscosity model for High viscous crude in the range (100cp-500cp) in a vertical oil well as it relates to well for upward flow as it relates to well performance. To investigate effect of high viscous oil in vertical well as it affects Liquid Holdup and pressure drop. The model develop was validated with Duns and Ros Model

Sensitivity analysis using different values of Superficial; liquid and gas velocities show its effects on oil well performance. At very low values of superficial liquid (0-05m/s to 0.1 m/sand gas (0.5 m/s to 2m/s), 2.067 in (50.8mm) velocities at high liquid viscosity of 500cp positive frictional pressure exist. Total pressure increases when frictional pressure increase resulting from increase in liquid holdup due to high viscosities liquid. The Model develop can be used to predict adequately liquid Holdup and Pressure drop for High Viscous crude.

The study made use of the result of the heavy oil viscosity Data gotten from the oil wells in Niger Delta to compare with the results of the model develop and that obtain from Duns and Ros Model

Available literature reveal that a model is yet to be develop that capture the behavior of High Vicious crude in the range ( 100cp to 500cp ) as only experimental studies that have been carried out as shown in the Table 1 below.

| **Experiments Performed on High Viscosity Two –Phase Upward Flow in Vertical Pipes** | | | | | |
|---|---|---|---|---|---|
| Research Group | Liquid Viscosity (cp ) | Internal Diameter (ID)mm | Vsl ( m/s ) | Vsg ( m/s) | Flow Patern |
| Schmidt Z et al 1984 | 108 | 76 | - | - | INT |
| Spisak et al 1994 | 1300 | 25 | 0.1.0.2 | 0.05-0.2 | INT |
| McNeil 2003 | 50,200,500 | 26.1 | 0.2-2.0 | 12-110 | ANN, INT |
| Sakharov et al 2004 | 700 | 60,73,89 | 0.1-0.4 | 0-1 | INT |
| Schmidt J et al 2008 | 900-7000 | 54.6 | 0.05-3.4 | 0-30 | BBL,INT,ANN |
| Akhiyarovetal 2010 | 100,500 | 52.5 | 0.1-1.0 | 0.5-4.0 | INT ( SLUG ) |

*Table 1: Experiments Performed on High Viscosity Two –Phase Upward Flow in Vertical Pipes*

*Hydrodynamic Model*

The model develop was based on the Dynamic of Slug flow. Other models are Bubble flow, annular flow and Mist flow.

### *1.1. Modeling of Slug Flow*

The dynamics of slug flow and the film flow zone were the basis that characterize the Hydrodynamic model developed and the film in the slug unit is used as the control volume. Pressure, Temperature, Oil gravity, gas Gravity, and gas Solution dictate the behavior of oil viscosity. Oil viscosity and velocity gradient is inversely related an increase in viscosity brings about reduction in velocity gradient. Shear force per unit area is used to determine value of viscosity as viscosity increase the pressure decrease

### *1.2. Mathematical Modeling*

A model that is symbolic was built to simulate and predict the viscosity effect on well performance. In developing the model, the following assumptions were made: Fully mixed liquid phase and the hydrodynamic of modeling based on slug flow patterns. However more flow patterns indications of more discontinuity and greater complexity in the hydrodynamic and also indicative of flow pattern transition.

The Pressure gradient and the Liquid holdup of the dynamic of slug flow because it shears transition boundaries with other flow pattern .The Equation of slug flow use to calculate slug characteristics is use to predict transition from slug flow to other flow pattern and Slug flow (stratified) in the film region and fully mixed in the slug region.

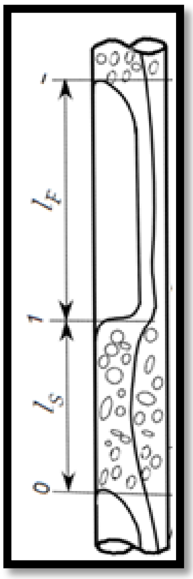

*Figure 1: Film Body and Slug Body Region Use in Modeling the Liquid Holdup Model*

1.2.1. Slug Length

The slug length is related to pipe diameter according to Taitel et al ( 1980 ) and Barnea and Branuer ( 1985 )slug length for vertical pipe is Ls =16dr

1.2.2. Slug Liquid Holdup

Slug liquid hold up is the balance between turbulent kinetic energy of the liquid phase and the surface free energy of the dispersed gas bubble in the slugbody.

In flowing a well the following occurs

A variable friction loss occurs as a result of the liquid velocity along the pipe vary over a short distance as There are situation where the gas moves at higher velocity than the liquid. The density of the gas liquid mixture is greater than the corresponding density corrected for down hole temperature and pressure that is calculated for produce from the gas liquid ratio. The liquid has very little effect on the wall friction loss when is almost completely entrained in the gas and that which influence pressure drop is the difference between the velocity and geometry of the two-phase flow.

A deep well that is producing a light oil from a reservoir that is near its bubble point the flow regime occur in the manner bubble flow occur at the bottom of the hole with little free gas present and other flow regime follows as gas continue to come out of solution and pressure decrease. The predominate regime is the slug flow however mist flow occur in condensate and steam stimulated wells.

*1.3. Features of Slug Flow*

A slug flow is recognized by the following feature below.

The gas Phase is more Pronounced and the liquid Phase is continuous. Gas bubble coalesce and form stable bubble that are almost the same size as the diameter of the pipe and the gas bubble are separated by slugs of liquid.

The bubble velocity is greater than that of the liquid and is predicted in relation to the velocity of the slug there is a film of liquid around the gas bubble the liquid velocity is not constant, the liquid slug always moves upward in the direction of the bulk flow/The liquid in the film either move upward or downward at lower velocity. The varying liquid velocity brings about varying wall friction losses and liquid holdup then determines the flowing density. Liquid entrained in the gas bubble at higher flow velocities.

The liquid and the gas phases are predominating as they have effect on pressure gradient, the design of wells and pipelines is based on slug flow.

**2. Mass Conservation Equation**

In modeling of slug flow the following assumption are considered with reference to figure 1

The liquid film zone (liquid film and gas pocket) of slug unit is used as a control volume. Continuity equations are gotten considering the transitional velocity. At steady state mass input and output rate at left and right boundaries of the film region of the film is the same for a two phase flow ,there is no liquid entrainment at rate that are actually low.

The continuity equation for the two phases in the film zone are as follows.

$(1\text{-}H_{WGS})(v_T - v_{OS}) = H_{OF}(v_T - v_{OF}),$ (1)

The mixture velocities of the slug body and film zone

$(1 - H_{WGS}))(v_T - v_{OS}) + H(v_T - v_{WS}) = (1 - H_{OF} - H_{WF})(v_T - v_G)$ (2)

$v_M = v_{SG} + v_{SO} + v_{SW}$ (3)

And

The passage of slug body at an observation point

$v_M = H_{OF}v_{OF} + H_{WF}v_{WF} + (1 - H_{OF} - H_{WF})_{VG},$ (4)
$l_U v_{SO} = l_S(1 - H_{WGS})\mathrm{vos} + l_F H_{OF} v_{OF},$ (5)
$l_U v_{SG} = l_S[(1 - H_{WGS})vos + H_{WGS} \quad v_{WS}] \qquad +l_F(1 - H_{OF} - H_{WF})_{VG}$ (6)
$l_U = l_{S+} l_F$ (7)
*From equation 3.8 momentum exchange between oil phase in the slug body and the oil phase in film region*
$\rho_O H_{OF} A_{(V_T - V_{OF})(V_{OS} - V_{OF})}.$ (8)
*The frictional force acting on oil film at the wall and opposite direction*
*And at the interface between the oil and gas same direction are for gas pocket*
$-\tau_{OF} S_{OF} l_F$ (9)
And
$\tau_{11} S_{11} l_F$ (10)
Respectively.
*Gravitational force for the gas pocket*
$-\rho_O H_{OF} A_{lFg}$ (11)
$\frac{(P_2 - P_1)}{l_F} = \frac{\rho_O (V_T - V_{OF})(V_{OS} - V_{OF})}{l_F} + \frac{\tau_{11} S_{11} - \tau_{12} S_{12} - \tau_{OF} S_{OF}}{l_F} - \rho_{Og}$ (12)

Considering all forces above for fully developed slug flow, the momentum equation for oil film in the gas pocket is the gas density is smaller than the liquid density as such the momentum exchange below slug body in the gas pocket is negligible

Momentum exchange for gas pocket is below
$\frac{(P_2 - P_1)}{l_F} = -\frac{\tau_{11} S_{11} - \tau_{GS_G}}{(l - H_{OF} - H_{WF})A} - \rho_{Gg}$ (13)
Combining equation 12 and 13
$\frac{\tau_{12} S_{12}}{A}\left(\frac{1}{H_{WF}} + \frac{1}{H_{OF}}\right) - (\rho_W - \rho_O)g = 0$ (14)
For strictly oil flow in the slug body the momentum equation is
$\frac{(P_1 - P_O)}{l_s} = \frac{\rho_O \quad (V_T - V_{OS})(V_{OF} - V_{OS})}{l_S} \frac{-\tau_{10} S_{10} + \tau_{OS} S_{OS}}{H_{OG} A} - \rho_{Og}$ (15)
The unknown in the equations above are
$H_{WGS}, v_{WS}, l_F, H_{OF}, H_{WF}, v_{OF}, v_{WF}.$
And can be solved by equation (1and 2), (5, 6) and (12, 13, 14)

## 3. Solution Procedure

The flow chart below presents the solution procedure for the slug flow model

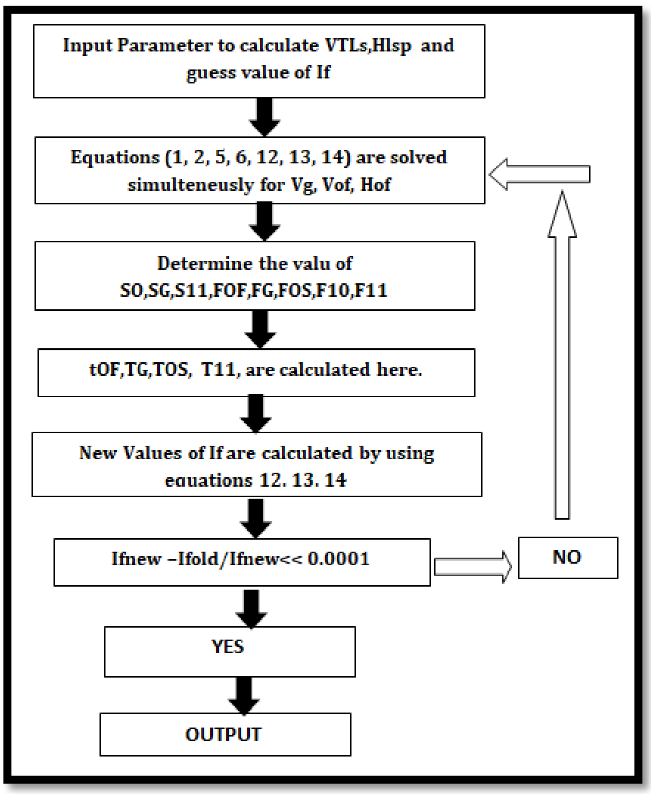


*Figure 2: Flow Chart for Calculation of Two Phase Slug Flow*

## 4. Model Development for Slug Liquid Holdup

From the relationship for liquid holdup in pipe,
HL = Volume occupied by liquid/Total volume of pipe. (16)
There are two velocities prevalent in the liquid slug body Vsl and the total velocity in the pipe Vp.
The liquid body has three components in a High viscious crude (oil)

1. The total velocity in the pipe Vp, associated with the liquid slug in the pipe Hlsp. This total velocity in the pipe is made up of the gas velocity and the slug and the film in the pipe.

2. The velocity of the liquid slug in the pipe Vlsp associated with the quantity of liquid in the pipe Hlsp.

3. The velocity of the liquid itself from equation (3.41) above where mathematically this can be stated the volume flowing per unit area of pipe V=PM and also Q=VA. The amount of liquid slug in the pipe can be stated thus.

$$V_{lsp} = \frac{V_{sl}+V_{sg}-V_{gsp}(1-H_{lsp})-V_{sg}H_{lsp}}{H_{lsp}} \quad (17)$$

$$H_L = \frac{V_p H_{lsp}-V_{slp}H_{lsp}+V_{sl}-V_{sg}}{V_p} \quad (18)$$

To determine Hlsp, Vlsp, Vp
$H_{lsp}$ =Liquid Holdup in slud in the pipe
$V_{lsp}$ =velocity of slug in the pipe
$V_p$ =Total velocity in the Pipe

### *4.1. Statistical Parameter Used to Evaluate Model*

The parameter used here are for examining the relative and actual error. They are average relative error (e1), absolute average relative error (e2), Standard deviation of relative error (e3), average actual error (e4), absolute average actual error (e5), standard deviation of actual error (e6). Equations are shown below and the results are shown in table 2 The parameter Vmodel and V field data represent the model prediction and the field data value.
The parameters for comparing errors are stated below.

$$e_i = \frac{((V_{pred}-V_{fieldData}))}{V_{fieldData}} x100 \quad (19)$$

$$e_j = (V_{pred} - V_{fieldData}) \quad (20)$$

$$\varepsilon_1 = \frac{1}{N}\sum_{i=1}^{N}(e_i)` \quad (21)$$

$$\varepsilon_2 = \frac{1}{N}\sum_{i=1}^{N}|(e_i)| \quad (22)$$

$$\varepsilon_3 = \sqrt{(\textstyle\sum_i^N(e_i-\varepsilon_1)^2)}/(N-1) \quad (23)$$

$$\varepsilon_4 = \frac{1}{N}\sum_{j=1}^{N}(e_j) \quad (24)$$

$$\varepsilon_5 = \frac{1}{N}\sum_{j=1}^{N}|(e_j)|. \quad (25)$$

$$\varepsilon_6 = \sqrt{\left(\sum_j^N(e_j-\varepsilon_4)^2\right)}/(N-1) \quad (26)$$

### *4.2. Interpretation of Parameters*

When (e1), and (e4) are Positive it shows model predict well but if the values are negative the model did not predict well.

| Comparisons | Statistical Parameters | | | | | |
|---|---|---|---|---|---|---|
| HL | $\varepsilon_1$ | $\varepsilon_2$ | $\varepsilon_3$ | $\varepsilon_4$ | $\varepsilon_5$ | $\varepsilon_6$ |
| HLnew_Model | 5.2756 | 5.2756 | 78.6048 | 1.0012 | 1.0012 | 0,8402 |
| HLnew_DUN ROS | -7.1421 | 7.1421 | 59.4506 | 0.4883 | 0.4883 | 0.3778 |
| DP/DL | $\varepsilon_1$ | $\varepsilon_2$ | $\varepsilon_3$ | $\varepsilon_4$ | $\varepsilon_5$ | $\varepsilon_6$ |
| DP/DLnew_Model | 10.2185 | 10.2185 | 186.9694 | 2630.445 | 375.7779 | 629.4940 |
| DP/DLnew_DUN ROS | -118.44 | 118.445 | 300.889 | -4406.46 | 629.4939 | 4114.3501 |

*Table 2: Pressure Gradient and Liquid Holdup Evaluation for Model*

From Table 2above the average relative error, $\varepsilon_1$and average relative actual error $\varepsilon_4$ are positive values showing the model predict correctly the Liquid Holdup. But these values are negative for Dun and Rosshowing that the model did not predict correctly.

4.2.1. Positive Frictional Pressure Gradient

As reported by Sakharov and Mokhov (2004) Increase in viscosity brings about positive frictional gradient for the model developed at low superficial liquid rate of (0.05 to 0.1 m/s superficial velocities and (0.5 to 2 m/s superficial gas velocities. At constant superficial liquid velocities, the gravitational (elevation) pressure gradient decreases monotonically as the superficial gas velocity increase for the fact that the liquid holdup is reducing and at this point the frictional pressure gradient is at minimum. This results in a minimum pressure. Total pressure gradient for the fact that the frictional pressure gradient overcomes the gravitational pressure gradient as the gas flow rate increase,

The frictional pressure gradient is average over the slug unit which is made up of the slug and film region .This phenomenon normally occur when the film length fall below and its wall friction force (upward) eventually becomes greater than the slug wall friction (downward).this is noticeable at slug to slug unit length ratio and low superficial oil velocities. This occurrence is also related to the gas lift effect the total pressure gradient is less than the gravitational pressure gradient. At this point it require lesser pressure drop to sustain the flow than the hydrostatic pressure drop even after the flow is terminated with the same oil holdup.

**5. Analysis of Model Evaluation**

The entrainment of gas bubble in the liquid film is responsible for the difference in prediction by the model and the filed Data. Oil holdup are usually more than the no slip holdup at low flow rates as slippage between the phases occurs gas flow much faster than oil. Crude oil of high viscosity in the range of 100cp ( 0.1 Pa s ) to 500cp (0.5 Pa s) obtain from field Data for two phase upward vertical flow Of Well_XX in Niger Delta to evaluate different model. Model evaluation was carried out for average liquid holdup and pressure gradient. Slug flow pattern was used in the evaluation.

| Parameter | Value |
|---|---|
| Api gravity | 29 |
| Density of Oil | (884.8 kg/m#)55.21 lbm/ft3 |
| Low and high flash point | 5F to 500F |
| Surface tension | 36 dyne/cm |
| Gas density | ( 47.09 Kg/m3)2.94 lbm/ft3 |
| Superficial liquid velocities | 0.1 to 1 m/s |
| Superficial gas velocities | 0.5 to 4.0 m/s |
| Gas oil ratio, gor | 50- 4000 scf/STB |
| Temperature rand | 100to 40 F |
| Inlet pressure | 380 psi |
| Diameter of pipe | 2.067 in (50.8mm) |

*Table 3: The Field Data Used for the Model*

Density difference, surface tension, size of droplet and residence time are the variable considered in the separation of gas and high viscosity oil.

The pressure gradient increases as superficial liquid velocity increase at constant superficial gas velocities. As liquid viscosities reduce there is a change from slug flow to churn flow as the superficial gas velocities increases.

For gas lifted well minimum total pressure gradient occur under intermittent flow as liquid holdup is reduce and that in turn reduce the gravitational pressure gradient and total pressure gradient in the tubing that bring about stable flow which is the best for oil and gas production in vertical wells. The minimum pressure gradient that occurs for lower gas rate than for low liquid viscosity gas lift is not suitable for high viscosity oil. This is because increase in gas injection rate made the pressure gradient to shift to a higher value than the minimum required. Flow pattern changes from intermittent to annular at small value of gas rate as the flow rate are not favourable here and gas lift is not efficient here.

At high liquid viscosities and at very low liquid and gas superficial velocities a positive pressure gradient occurs. However as liquid viscosity increases the frictional and gravitational pressure, gradient increases with liquid holdup increase.

**6. Liquid Holdup**

At constant superficial liquid velocities (0.05m/s), as he average liquid holdup decrease as the superficial gas velocity increase. at constant superficial gas velocities (1m/s) the average liquid holdup increases superficial liquid velocity increases. Increase in shear stress increase liquid accumulation as such increase in liquid viscosity increase the liquid holdup. As the superficial gas and liquid viscosities increase liquid holdup increase as liquid viscosities increase. In the range of low gas and liquid flow rate the existing mechanistic model have less uncertainty for high liquid viscosity.

Various researchers have worked on High Vicious crude as captured in Table 4.2 all of them conducted experiment and have shown that in all their experiment that the existing mechanistic model were develop and validated with low viscous crude and today the search for oil more of high viscous crude is being found and less of low viscous crude are being found as such these model develop and validated for low viscous crude do not adequately predict liquid hold up and pressure drop for High Viscous crude. They use the following models Duns and Ros (1963 ), Hagedorn and brown (1965), Orkiszewskwe (1967 ), Aziz et al ( 1972 ), Beggs and Brill (1973 ), Taitel et al (1980), Ozon et al (1987 ), Hassan and Kabir (1988 ), Ansari et al (1994), Zhang et al (2003a,b). and concluded the models were develop and validated for low vicious crude and these models when used for High Viscious crude show high discrepancies up to 27%

and error in prediction success of 43%. Existing model and correlations are developed from experimental data of low liquid viscosities (ul, 20 mPa.s).

**7. Discussion**

The evaluation results for liquid hold up and pressure gradient are shown in Table 4.7 the model develop gave reasonable values for six statistical parameters for liquid hold up and pressure gradient.

The model develop was validated by Duns and Ros model and presented in figures 3, 4. 5 the two models were evaluated against field data. The model develops performed better as this is shown in Table 3 the average relative error, average actual error, absolute average relative error, absolute average actual error, Standard deviation of relative error, standard deviation of actual error respectively

The develop model predicted pressure drop with sufficient accuracy that it was validated with work of all other mechanistic Duns and Ros condition which in terms of flow regime and liquid distribution

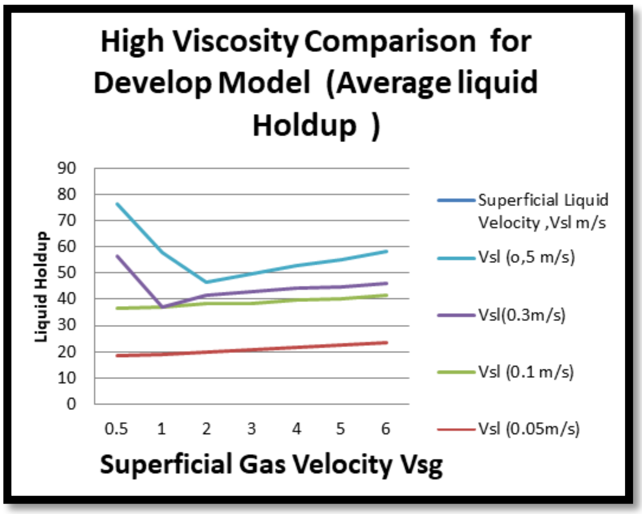


*Figure 3: High Viscosity Comparison for Develop Model (Average Liquid Holdup) for Vsl a. 0.05m/s b. 0.1 m/sc. 0.3 m/s d. 0.5 m/s for Develop Model*

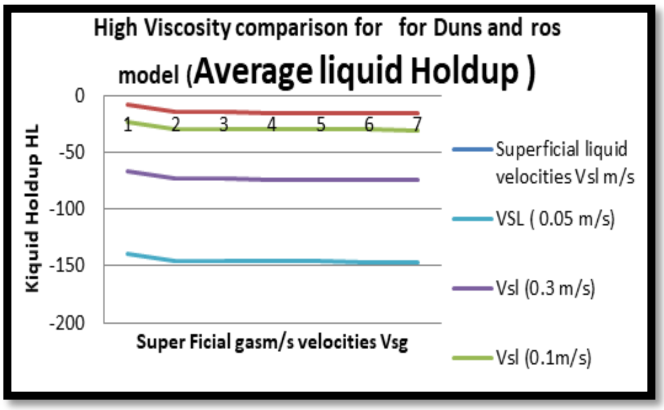


*Figure 4: High Viscosity Comparison for Mechanistic Dunsmechanistic Duns and Ros Model Average Liquid Holdupfor Vsl A. 0.05m/S B. 0.1 M/S C. 0.3 M/S D. 0.5 M/S for*

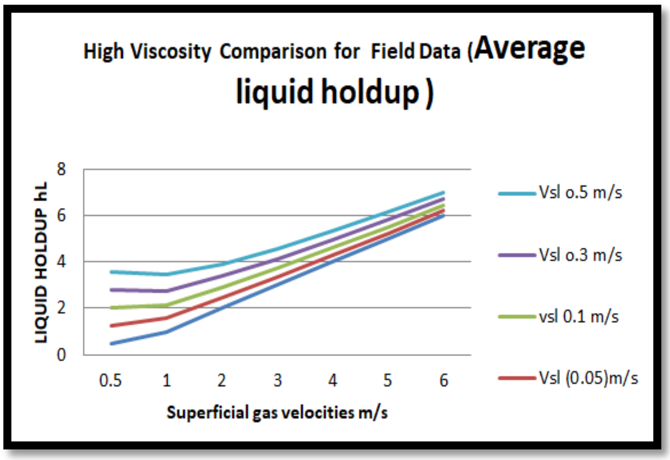


*Figure 5: High Viscosity Comparison for Field Data (Average Liquid Holdup) for Vsl A. 0.05m/S B. 0.1 M/S C. 0.3 M/S D. 0.5 M/S*

As shown in the graph fig 6 ,, 7.,8 above at constant superficial liquid velocities , as he average liquid holdup decrease as the superficial gas velocity increase . at constant superficial gas velocities, the average liquid holdup increases superficial liquid velocity increases.

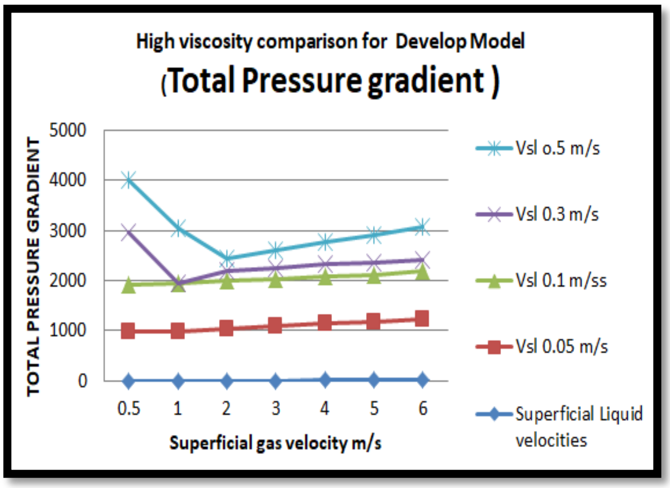


*Figure 6: High Viscosity Comparison for Develop Model (Total Pressure Gradient Forvsl A. 0.05m/S B. 0.1 M/S C. 0.3 M/S D. 0.5 M/S for Develop Model*

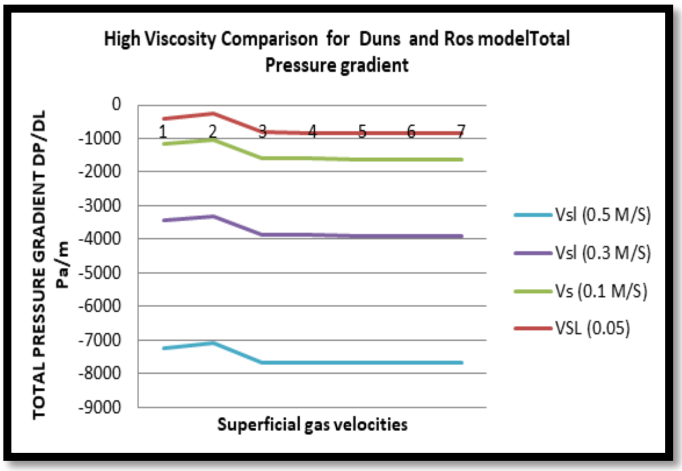


*Figure 7: High Viscosity Comparison for Duns and Rosmodel Total Pressure Gradient for Vsl A. 0.05m/S B. 0.1 M/S C. 0.3 M/SD. 0.5 M/S for Duns and Ros Model*

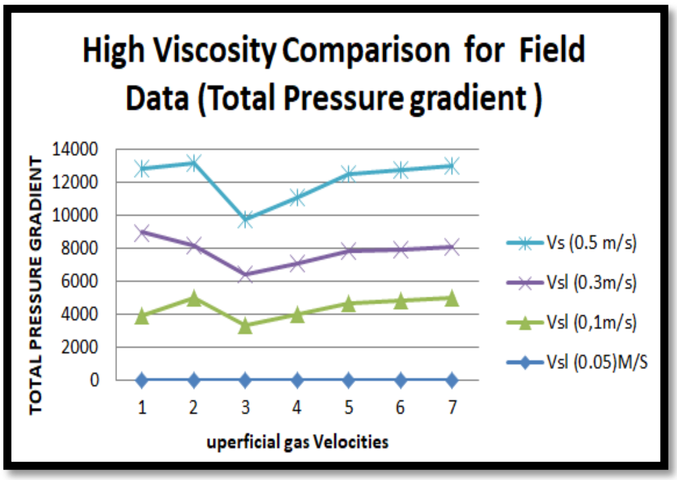


*Figure 8: High Viscosity Comparison for Field Data (Total Pressure Gradient) for Vsl A. 0.05m/S B. 0.1 M/S C. 0.3 M/S D. 0.5 M/S For Field Data*

From fig 6 and 3 above Increase in viscosity brings about positive frictional gradient at low superficial (0.05m/s) liquid rate. At constant superficial liquid velocities the gravitational (elevation) pressure gradient decrease monotonically as the superficial gas velocity increase from (1m?s TO 6m?s) for the fact that the liquid holdup is reducing and at this point the frictional pressure gradient is at minimum. This result in a minimum pressure. Total pressure gradient for the fact that the frictional pressure gradient overcomes the gravitational pressure gradient as the gas flow rate increase,

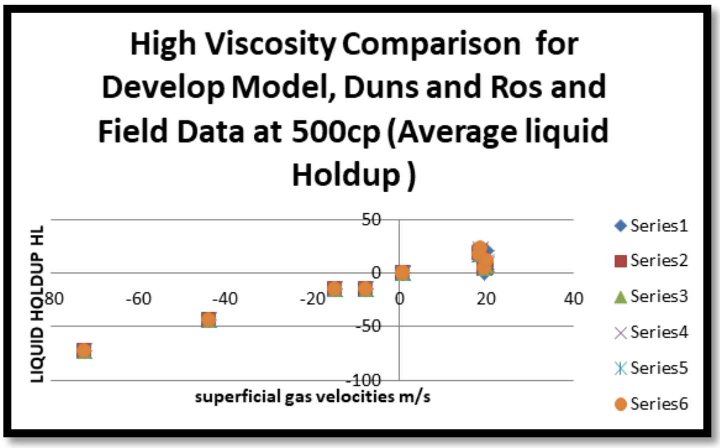


*Figure 9: High Viscosity Comparison for Develop Model, Duns and Ros and Field Data at 500cp (Average Liquid Holdup)*

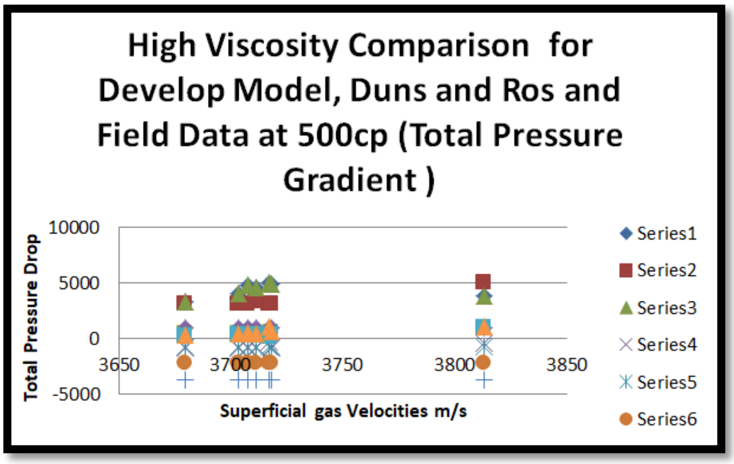


*Figure 10: High Viscosity Comparison for Develop Model, Duns and Ros and Field Data at 500cp (Total Pressure Gradient)*

From the plot of figure 9 and 10 above the Data that represented correctly are the Data for the developed model

**8. Conclusions**

The conditions that are varied in predicting pressure drop are well rate, gas oil ratio GOR, tubing size, water cut and fluid properties. In the research liquid holdup is considered in calculating the density and slip velocity is considered. (difference between the liquid and the gas velocity)., the wall friction losses are determined from fluid properties

Pressure gradient and liquid holdup depends on flow pattern so accurate prediction of flow pattern is very important. Increase in liquid viscosities result in lower intermittent region

Available model predict pressure gradient better at lower oil viscosities between (10cp – 100cp). Duns and Ros (1964), the model developed was able to predict oil viscosities of 100cp and 500cp. The poor prediction of pressure gradient by model is as a result of not identifying the right flow pattern as each model is flow pattern dependent.

At very low values of superficial liquid of (0.05 to 1.0m/s) and gas (0.5m/s to 2m/s) velocities at high liquid viscosity (above 100cp to 500cp) positive frictional pressure exist. Total pressure increase when frictional pressure increase resulting from increase in liquid holdup due to high viscosities liquid

New closure relationship should be developed for high viscosity liquid in slug flow. So that the New characteristics closure relationship as slug liquid holdup, Translational velocity, slug length ,slug frequency for high viscosity liquid to be deployed in available mechanistic model in order to improve their performance for high viscosity liquid slug..

There is usually low drainage of high viscous crude (oil) as a result of liquid film on top of the pipe during flow. The top oil film in the slug characteristics need to be investigated to model its effect in the mechanism of flow.

*8.1. Nomenclature*

$H_{lsp}$ =Liquid Holdup in slud in the pipe
$V_{lsp}$ =velocity of slug in the pipe
$V_p$ =Total velocity in the Pipe
A = cross section area
C = constant
d = pipe diameter
$\rho_0$ = Density of oil
$\rho_g$ = Density of gas
P= pressure
$V$= velocity
$\mu$= viscosity
$\tau$= shear stress

*8.2. Statistical Parameter*

(e1)= Average relative error,
(e2)=Absolute average relative error
(e3) =Standard deviation of relative error,
(e4) - average actual error,
(e5) = absolute average actual error
(e6) = standard deviation of actual error
$Vms$= Mixture Velocity
$V_{sl}$= superficial liquid Velocity
$V_{sg}$= superficial gas Velocity
$l_U$=slug unit

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