Temperature Distribution Model for Predicting the Precipitation of Wax in a Wellbore: (A Numerical Approach)

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Abstract—*In this research work, since wax deposition is strongly thermal related, an accurate heat transfer model is necessary and was developed in predicting and preventing wax deposition. The derivation of the temperature distribution prediction model took into consideration the three basic equations which are: The conservation law of mass equation, the conservation law of momentum equation and the energy balanced equation applied to a differential control volume of a pipeline. Application of these principles allows the development of a general temperature distribution model which can be applied to any inclination angle for either single or two phase flow. A program on excel was written for this temperature distribution model. Data were obtained from Chevron well (Dibi 40H), from Dibi field at Warri and some were obtained from rock and fluid literature text. These data were inputted into the program and that allows the calculation of changes in pressure and temperature as a function of distance, flow rate, production tubing diameter and inclination angle separately. Results were generated and graphs plotted showing the variation of temperature and pressure at different depths, tubing sizes, flow rates and inclination angles. An explanation was given to the different graphs and recommendations made.*

Index Terms—Wax Appearance Temperature (WAT), Flow Assurance, Integrated Production Management (IPM), Reservoir, Wax Precipitation, Aquifer.

1 Introduction

Flow assurance is a critical and expensive task in the oil and gas industry, especially when operating offshore. Flow assurance means to deliver and assure the transport of the well stream fluid from the reservoir to the process facilities. Flow assurance is designed in a way to identify, quantify and minimize the challenges with the flow risks such as solid depositions to avoid the reduction of the well stream flow, or in worst case complete clogging of the flow lines leading to cease production. A root cause of many oil industry production and flow problem is paraffin wax especially in cold and deep offshore fields. About 85% of the world's oil suffers when paraffin wax precipitates out and solidifies in the formation pores and fluid flow channels, at the wellbore, on the side walls of wells, in tubing, casing perforations, pump strings, and rods, and the complete oil transfer system of flow lines and pipelines etc. Paraffin wax deposition is costly, causing decreased production, equipment failures, bottlenecks, loss of storage and transport capacity, clogging of refinery pipe work, and loss of efficiency and revenue. The precipitation and deposition of this wax is majorly a function of temperature. The prediction of the time this temperature might occur has been a major challenge during the planning phase of a well. The accurate prediction of the wax precipitation temperature can help in planning preventive measures, which in turn can save the industry a lot of expenses on remedial treatment. In some reservoirs, crude oil contains waxy constituents which will precipitate from the oil when the temperature of the oil decreases to a value known as the wax appearance temperature (WAT). When this happens in a tubing string or flow line, a layer of wax builds up on the wall of the conduit and the process continues as long as the temperature of the flowing oil is at or less than WAT.

2 Materials and Methods

2.1 Materials

The simulators used for this study were limited to

- Petroleum Expert's PVTp
- Microsoft Excel VBA
- Matlab R2007a.

The Excel VBA simulator proved a useful tool in

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determination and simulation of certain desired unknowns across the wellbore system. The PVTp simulator which is integral to the IPM (Integrated Production Management) suite was used to accurately characterize the wellbore properties and also generate PVT properties of the well fluid system to be used for performance prediction modeling. Iterative solvers such as Matlab 2007a and Microsoft Excel 2013 also proved useful in updates of deduced wellbore parameters.

2.2 Fundamental Principles

The derivation of the temperature distribution prediction model will take into consideration the three basic equations which are: The conservation law of mass equation, the conservation law of momentum equation and the energy balanced equation applied to a differential control volume of a pipeline. Application of these principles allows the calculation of changes in pressure and temperature with distance.

2.3 Model Development

The conservation of mass simply means that for a given control volume, such as segment of a pipe, the MASS IN minus MASS OUT must equal the MASS ACCUMULATION. Therefore, applying steady state conservation of mass equation to a control volume leads to:

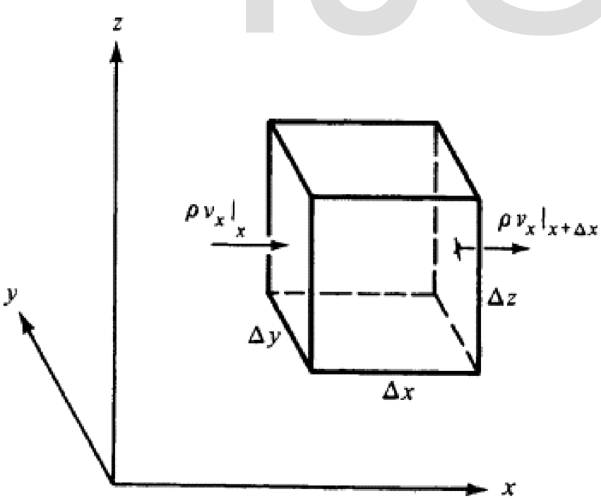

Figure 1: Control Volume for wellbore

{Rate of mass in} – {Rate of mass out} = {Rate of mass accumulation} (1)

Analyzing equation 3.1 mathematically gives:

Rate of accumulation of fluid in x, y, z-direction $=\frac{\partial\rho}{\partial t}(\Delta x\Delta y\Delta z)$ (2)

Rate of mass in x, y, z-direction$=\Delta y\Delta z\{(\rho v_x)_x\}+\Delta x\Delta z\{(\rho v_y)_y\}+\Delta x\Delta y\{(\rho v_z)_z\}$ (3)

Rate of mass out x, y, z – direction $= \Delta y\Delta z\{(\rho v_x)_{x+\Delta x}\} + \Delta x\Delta z\{(\rho v_y)_{y+\Delta y}\} + \Delta x\Delta y\{(\rho v_z)_{z+\Delta z}\}$ (4)

Combining equations (2) – (4) into equation (1)

$$\frac{\partial\rho}{\partial t}(\Delta x\Delta y\Delta z) = \Delta y\Delta z\{(\rho v_x)_x\} + \Delta x\Delta z\{(\rho v_y)_y\} + \Delta x\Delta y\{(\rho v_z)_z\} - \Delta y\Delta z\{(\rho v_x)_{x+\Delta x}\} - \Delta x\Delta z\{(\rho v_y)_{y+\Delta y}\} - \Delta x\Delta y\{(\rho v_z)_{z+\Delta z}\}$$

$$\frac{\partial\rho}{\partial t}(\Delta x\Delta y\Delta z) = \Delta y\Delta z\{(\rho v_x)_x - (\rho v_x)_{x+\Delta x}\} + \Delta x\Delta y\{(\rho v_z)_z - (\rho v_z)_{z+\Delta z}\} + \Delta x\Delta z\{(\rho v_y)_y - (\rho v_y)_{y+\Delta y}\}$$

$$\frac{\partial\rho}{\partial t}(\Delta x\Delta y\Delta z) = -\Delta y\Delta z\{(\rho v_x)_{x+\Delta x} - (\rho v_x)_x\} - \Delta x\Delta y\{(\rho v_z)_{z+\Delta z} - (\rho v_z)_z\} - \Delta x\Delta z\{(\rho v_y)_{y+\Delta y} - (\rho v_y)_y\} \quad (5)$$

Dividing equation (5) by ΔxΔyΔz gives

$$\frac{\partial\rho}{\partial t} = -\frac{\partial(\rho v_x)}{\partial x} - \frac{\partial(\rho v_y)}{\partial y} - \frac{\partial(\rho v_z)}{\partial z} \quad (6)$$

$$\therefore \frac{\partial\rho}{\partial t} = -\Delta(\rho v) \quad (7)$$

However, after so much integration and expansions, the temperature equation (8) below is the generalized one and can be applied to any inclination angle for either single or two phase flow.

$$T = (T_{ei} - g_e L\sin\theta) + (T_e - T_{ei})e^{\frac{-1}{A}} + g_e A\sin\theta(1-e^{\frac{-1}{A}}) + \frac{1}{\rho C_p}\emptyset A\frac{dp}{dL}(1-e^{\frac{-1}{A}}) \quad (8)$$

Assumptions of models

1. An incompressible fluid flow is assumed in the wellbore.
2. Water and gas injection effect was not considered.
3. The effect of pressure drop on temperature profile was assumed to be tremendous and considered.
4. The flow was considered under different wellbore flowing pressure.
5. Two phase flow in the production tubing was considered.
6. Bottom aquifer pressure support is inadequate for pressure maintenance.
7. Frictional effect during fluid flow in the tubing was assumed to be negligible.
8. Flow is unsteady and turbulent.

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3.0 RESULTS AND DISCUSSION

The results for the temperature model so developed in the course of this research will be validated, analyzed and discussed using field obtained parameters.

3.1 Variation of Pressure and Temperature at Different Well Depth

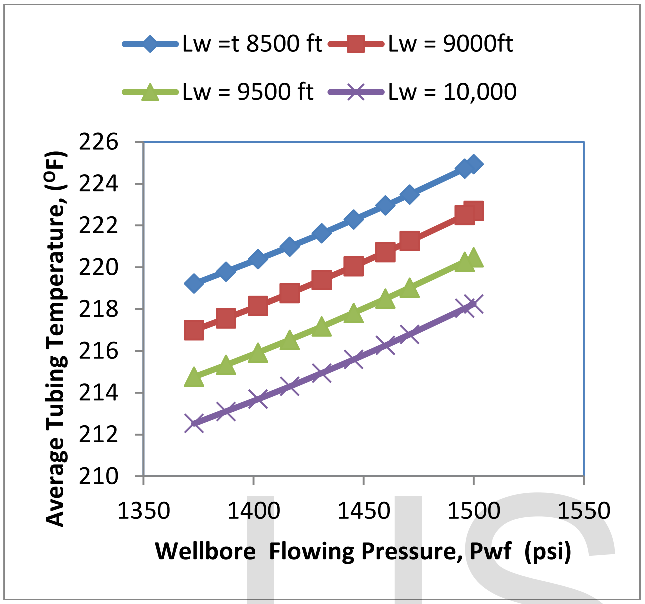

Figure 2: Variation of Average Tubing Flowing Temperature with Wellbore Pressure as a function of Well Depth

The figure above presents the variation of average well stream temperature with wellbore flowing pressure as a function of the well depth. Here, for a well depth of 10,000 ft, a minimum average tubing flow temperature of 212.53^{O}F at a corresponding wellbore flowing pressure of 1373 psi is forecasted. Conversely, a higher wellbore flowing pressure of 1500 psi is capable of maintaining the average tubing flow temperature to an average of 218^{O}F as compared to that of the 1373 psia flowing pressure. This is because; the longer and faster the distance travelled by the reservoir fluid through the tubing of a well, the more pressure is required. Since pressure and temperature relationship for most hydrocarbon mixtures have been established to be characterized as direct proportionality, a higher flowing pressure with a higher kinetic energy in fluid particles is more likely to sustain well stream temperature above the environmental temperature and slightly below formation temperature, which can comfortably retard wax precipitation. Lower well depths of 9500 ft, 9000 ft and 8500 ft with corresponding minimum temperatures at 214, 216 and 219^{O}F at the lowest wellbore flowing pressure of 1371 psi as compared to the 212^{O}F for the 10,000 ft well confirms that the deeper the well, the lower the average fluid temperature in the tubing, the higher the tendency of the tubing fluid approaching a wax precipitation temperature.

3.2 Variation of Pressured Drop and Temperature at Different Well Depth

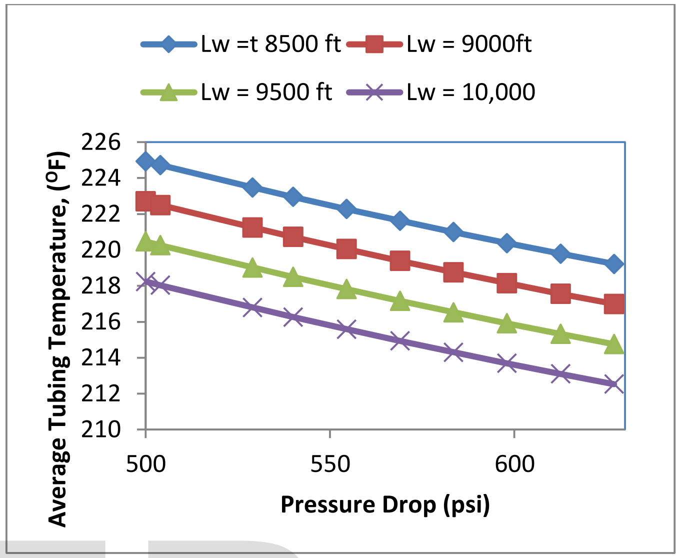

Figure 3: Variation in Average Tubing Flowing Temperature with Pressure Drop as a Function of Well Depth

Figure 4.2 above shows the drawdowns of the individual flowing well bore pressure and their corresponding average tubing flow temperature at different depths. As observed in the Temperature vs Pressure plot of figure 4.1, the higher the Pwf, the Higher the Temperature, the well depth notwithstanding. Pressure drop analysis reveals the inverse in the sense that the higher the pressure drop in the well, the lower the average tubing temperature. For a well depth of 8500 ft, a wellbore flowing pressure of 1500 psi with a corresponding pressure drawdown of 500 psi, the average flowing temperature in the tubing is 224 ^{O}F. This compared to a lower well bore flowing pressure of 1317 psi with a corresponding pressure drawdown of 627 psi which records a 218 ^{O}F reveals that the higher the pressure drop, the lower the average tubing temperature. This implies that at higher pressure drops wax precipitations phenomenon is likely to occur as the fluid loses more energy by virtue of the reduced pressure (of which temperature is directly proportional to). The same trend is observed for well depths of 9000 ft, 9500 ft and 10,000 ft. a lower well depth with a higher pressure drop will record a higher fluid temperature as compared to a longer well depth at same pressure drawdown value which yields a lesser tubing flow temperature.

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3.3 Variation of Pressure and Temperature at Different Flow Rate.

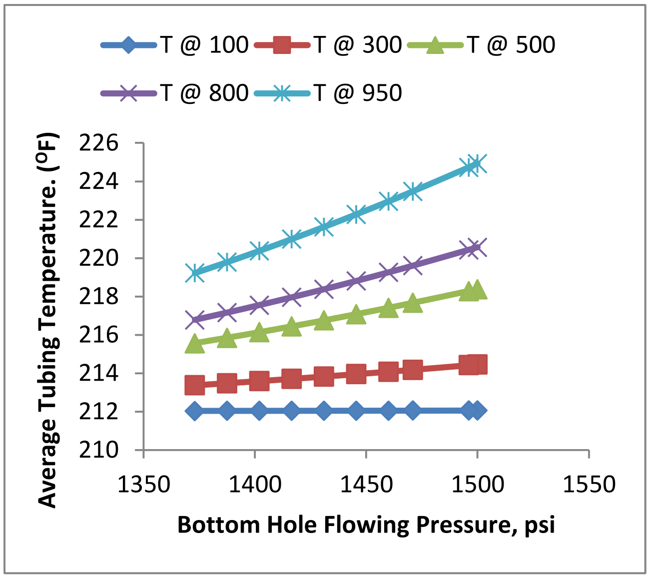

Figure 4: Variation of Average Tubing Flowing Temperature with Wellbore Pressure as function of the Flow Rate

The figure above presents the variation of average well stream temperature with wellbore flowing pressure as a function of different flow rates. Here, for a flow rate of 950 $M\,{}^{STB}/_{Day}$, a minimum average tubing flow temperature of 219.53^{O}F at a corresponding wellbore flowing pressure of 1373 psi is forecasted. Conversely, a higher wellbore flowing pressure of 1500 psi is capable of maintaining the average tubing flow temperature to an average of 225^{O}F as compared to that of the 1373 psia flowing pressure. This is because, the faster the flow rate, the more the pressure is required to lift the flowing fluid to the surface. Since pressure and temperature relationship for most hydrocarbon mixtures have been established to be a direct relationship, a higher flowing pressure with a higher kinetic energy in fluid particles is more likely to sustain well stream temperature above the environmental temperature and slightly below formation temperature, which can comfortably retard wax precipitation. Smaller flow rates of 100, 300, 500 and 800 $M\,{}^{STB}/_{Day}$ with the corresponding minimum temperatures at 212, 213.3 and 215.7^{O}F respectively at the lowest wellbore flowing pressure of 1373psi as compared to the 219.53^{O}F for the 1373psi shows that the slower the flow rates in the production tubing, the lower the average fluid temperature in the tubing, and the higher the tendency of the tubing fluid approaching a wax precipitation temperature.

3.4 Variation of Pressure Drop and Temperature at Different Flow Rates

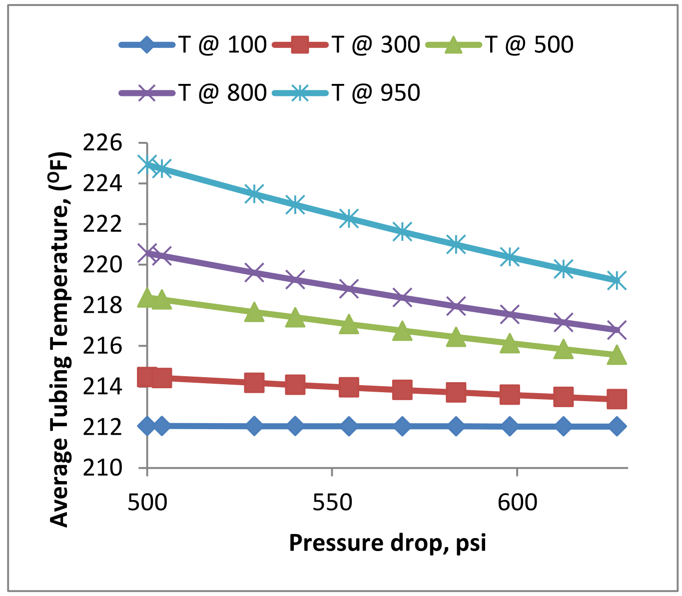

Figure 5: Variation in Average Tubing Flowing Temperature with Pressure Drop as a Function of Different Flow Rates.

The Figure above shows the drawdowns of the individual flowing well bore pressure and their corresponding average tubing flow temperature with different flow rates. As observed in the Temperature vs Pressure drop plot, the analysis reveals that the higher the pressure drop in the well, the lower the average tubing temperature at different flow rates. For a flow rate of 950 $M\,{}^{STB}/_{Day}$, a wellbore flowing pressure of 1500 psi with a corresponding pressure drawdown of 500 psi gives the the average flowing temperature in the tubing as 225 ^{O}F. This compared to a lower well bore flowing pressure of 1317 psi with a corresponding pressure drop of 627 psi which records a 221^{O}F reveals that the higher the pressure drop, the lower the average tubing temperature irrespective of the flow rates. This implies that at higher pressure drop, wax precipitation phenomenon is likely to occur as the fluid loses more energy by virtue of the reduced pressure (of which temperature is directly proportional to). The same trend is observed for lower flow rates of 100, 300, 500, 800 $M\,{}^{STB}/_{Day}$. A lower flow rates with a higher pressure drop will record a lower fluid temperature as compared to a faster flow rate at same pressure drop value which yields a higher average tubing flow temperature.

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4 CONCLUSION

In the wellbore, oil temperature drops after oil leaves the reservoir due to heat loss to the surroundings. In some cases, prediction of the temperature profile is crucial to flow assurance, optimization of the oil production strategy and minimization of the cost. Temperature prediction of waxy oil is more complicated. In some reservoirs, crude oil contains waxy constituents which will precipitate from the oil when the temperature of the oil decreases to a value known as the wax appearance temperature (WAT). When this happens in a tubing string or flow line, a layer of wax builds up on the wall of the conduit and the process continues as long as the temperature of the flowing oil is at or less than WAT. The wax deposit reduces the effective diameter as wax deposition increases the thickness of the wax layer. As a consequence, the production rate decreases under a fixed pressure drop. When the production rate is too low, the conduit is shut down and the wax has to be removed by scraping from the walls or by injecting hot oil or other solvent to dissolve the deposit. In the worst case, the conduit may become plugged with wax and flow ceases abruptly.

In this research work, since wax deposition is strongly thermal related, an accurate heat transfer model is necessary and was developed in predicting and preventing wax deposition. The derivation of the temperature distribution prediction model took into consideration the three basic equations which are: The conservation law of mass equation, the conservation law of momentum equation and the energy balanced equation applied to a differential control volume of a pipeline. Application of these principles allows the development of a general temperature distribution model which can be applied to any inclination angle for either single or two phase flow. A program on excel was written for this temperature distribution model. Data were obtained from Dibi field in Niger Delta and some were obtained from rock and fluid literature text. These data were inputted into the program and that allows the calculation of changes in pressure and temperature as a function of distance, flow rate, production tubing diameter and inclination angle separately. Data were generated and graphs plotted showing the variation of temperature and pressure at different depths, tubing sizes, flow rates and inclination angles.

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