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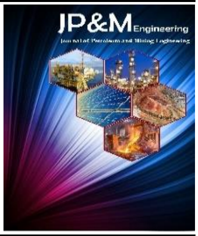

Impact of Water cut increase and Emulsion Viscosity variation on Pressure Gradient during oil Production

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Abstract

Evaluation and prediction of emulsion flow behavior will play a pivotal role in reduction of flow assurance issue resulting from emulsion. Although emulsions formation cannot be completely stop but can be reduced and mitigated by optimization of water content. In this work, PROSPER a well modeling package was used to develop a wellbore model to investigate water cut increase on pressure gradient within the wellbore during heavy oil recovery. Gradient traverse estimation were implemented at a wellhead pressure of 500 psig and a liquid rate of 1500 STB/day. The model was run for with and without emulsion viscosity for no water cut (base case) and water cut of 25%, 50% and 75%. Results shows that as the water cut increases, the bottom hole flowing pressure(BHFP) and pressure gradient decreases for without emulsion viscosity and increases for with emulsion viscosity scenario.Base case of no water cut gave the same pressure gradient for with and without emulsion viscosity. The sensitivity scenario without emulsion had 3.5%, 6.2%, and 8% reduction in pressure gradient for 25%,50% and 75% water cut when compared with base case. Further analysis reveals that for with emulsion there was 3.4%, 11.2% and 14.6% increase in the pressure gradient for 25%,50% and 75% water cut when compared with base case .For higher water cut (25%, 50%, 75%), there was a separation between the two gradient. The pressure drop increases with emulsion viscosity increase. High water cut increases the difference between the two due to emulsion viscosity increase.

Introduction

Water-in-crude oil emulsions formation during oil production can result in a major reduction of the production rates. This arises due to the high effective viscosity of the emulsion that increases with the content of water near the phase inversion point. Phase inversion is the moment where water-in-oil emulsions are inverted to oil-in-water emulsions or reversed, due to variations in the volumetric ratios of the phases .The oil-water dispersed flow is one essential flow behavior of the two-phase flow conditions and can be found in a variety of petroleum industries where it usually happens in the flow paths from rock cracks in stratum to oil wells and from well heads to multipurpose stations, even pipelines, inside the stations, particularly during the later years of oil production. Stable emulsions cause a larger value of flow pressure loss (Wong *et al.,* 2015; Pal, 1993; Nädler and Mewes, 1997; Keleşoğlu *et al.,* 2012; Plasencia *et al.,* 2013). when dilute emulsions are generated at low water cuts, the viscosity behavior is dictated by the hydrodynamic forces.The resistance to flow of the fluid can be created by deformation and rearrangement of the network architectures of the thin liquid films between pressure drop resulting from increase in water cut increases, towards highly concentrated emulsions(Otsubo and Prud'homme, 1994). Plasencia *et al.,* (2013) found that the pressure drop of water-in-oil emulsions might increase up to 8 times greater than the pure oil pressure drop.

The modeling and prediction of the pressure gradient of oil-water flow in wellbore and pipelines is very significant and has received attention. Angeli and Hewitt, (1998) indicated that pressure gradients reached their limits when the point of phase inversion was achieved. Pressure gradients is affected by flow regime, tubing properties, drag reduction, yet experiment data did not matched well with empirical equations. With experiments, Flores *et al.,* (1998) explored the influence of flow patterns, velocity and entrance water holdup on the pressure gradient, and evaluated the frictional pressure gradients of oil-water and water-oil emulsion. Cai and Chen (1999) found that high mixture velocity increases the pressure gradients and with significant effect account effect from water holdup . Chen *et al.,* (2001) did oil-water experiments and found that pressure gradients were largely reliant on the viscosity of the continuous phase and high mixture velocity increased the pressure gradients. pressure gradients was expressed as a function of mixture velocity and effective viscosity and increases at high mixture velocity(Gong and Mu, 2004; Kang *et al.,* (2006).Other variables which essentially influence pressure gradients are oil and water superficial velocities, diameter of pipe, roughness of pipe, and viscosity of oil (Al-Wahaibi and Mjalli ,2014).

Effective prediction of pressure gradient will lead to the improved design of an efficient energy transportation system. The flow pressure drop profile is a valuable tool for production optimization in the upstream oil industry. With the flow pressure drop profile, the optimum pressure drop for a pipeline can be anticipated more correctly, and the influence of emulsions on the flow pressure drop is more clearly understood. In literature, the influence of increasing cut during production on pressure gradient has not been evaluated. Hence, this work will examine pressure gradient with and without emulsion viscosity model correction for increasing water cut

Methodology

2.1 Fluid Properties and Data Description

The model configuration, fluid properties, black oil correlation, emulsion model , viscosity variation with water cut, deviation and tubular data are presented in Table1, 2, 3, 4 ,5,6 and 7

Table 1 Model configuration option data

Property Specification	Specification
Fluid type	Oil and Water
Fluid properties calculation method	Black Oil
Separator type	Single-Stage Separator
Emulsions	Emulsion + Pump Viscosity Correction
Well completion type	Cased hole
Flow type	Single branch

Table 2 Fluid properties data

Property	Value
Solution GOR	40 SCF/STB
Gas Gravity	0.83
Water salinity	10000ppm
Oil gravity	11°API
Mole % H_2S	0%
Mole % CO_2	0%
Mole % N_2	0%

Table 3 Black oil correlation matching data

Pressure (psig)	GOR (scf/STB)	Oil FVF (RB/STB)	Viscosity (cP)
500	40	1.051	100

Table 4 Emulsion model calibration data

Property	Value
Experimental pressure	2000psig
Experimental temperature	200°F
Minimum water cut for maximum viscosity	60%
Maximum water cut for maximum viscosity	80%

Table 5 Viscosity variation with water cut

Water Cut	Emulsion viscosity (cP)
5	105
10	115
20	130
30	150
40	188
50	234
55	250
85	53
90	10.5

Table 6 Deviation survey data

Measured Depth (ft)	True Vertical Depth (ft)
0	0
1000	1000
2000	2000
3000	3000
4000	4000
5000	5000

Table 7 Downhole equipment data

Type	Measure Depth (ft)	Inside diameter (inch)	Roughness (inch)
Xmas Tree	0	-	-
Tubing	4800	2.4	0.0006
Casing	5000	6.4	0.0006

2.2 Wellbore Model and Simulation work flow for Pressure Gradient

The Petroleum Experts PROSPER was used to develop wellbore model. The model configuration, fluid properties, Black oil correlation matching, and Emulsion model calibration was selected and entered (Table 1 to Table 4). The wellbore configuration was described with the survey data in Table 6 and Table 7.The black oil correlation was matched against the laboratory data at 500psig and 200°F. With a good match on fluid properties when producing crude oil with insignificant water cut (no water cut), and when water of higher percent was introduced, an emulsion was formed.

To match the emulsion data, emulsion occurrence drop model was selected and the data in Table 5 was entered for the matching. Gradient traverse at a wellhead pressure of 500 psig and a liquid rate of 1500 STB/day was implemented to determine the pressure gradient within the well for a given set of water cut condition (25%, 50% and 75%). This was determined first without the emulsion data and then with the emulsion data so as to compare the resulting pressure gradient for each water cut. The simulation work flow is presented in Figure 1.

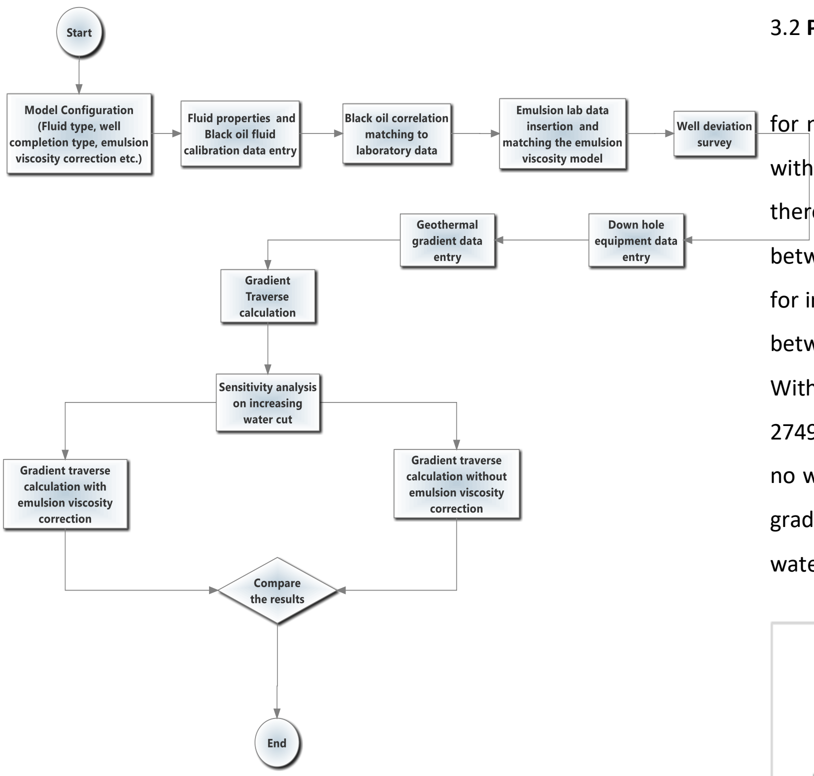

Figure 1 Simulation workflow

Results

3.1 Emulsion viscosity

The emulsion viscosity curve consist of three distinct regions; viscosity equal to that of the oil (no water cut) and increases with water cut up to the maximum viscosity(plateau). The second region is the plateau. At the maximum, there was a drop up to 100% water cut and the fluid viscosity was equal to viscosity of water. Figure 2 shows the emulsion viscosity curve at different water cut percentages. There was an increase in the emulsion viscosity water cut up 60% and with a plateau value to 80%. This represents the inversion point (inversion water cut) at which it changes from water-in-oil to oil-in-water.

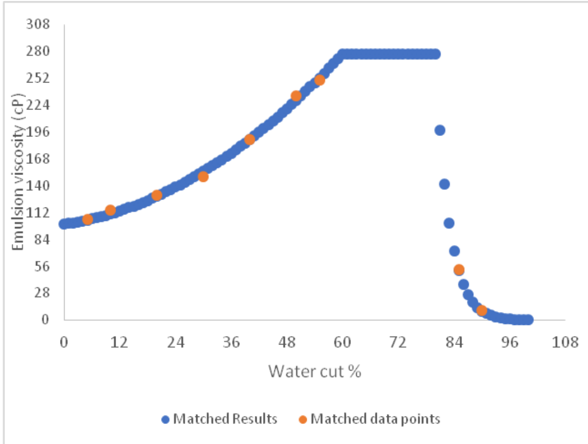

Figure 2 Experimental and simulated emulsion viscosity

3.2 **Pressure gradient without emulsion viscosity**

Figure 3 shows the pressure profile along the wellbore for no water cut, 25%, 50 % and 75% water cut for the case with no emulsion viscosity. For those cases with water cut, there was formation of an emulsion and separation occurs between the gradient curves. The pressure drop was higher for increase in emulsion viscosity. There was a high difference between the two due to increase in emulsion viscosity. Without emulsion viscosity, a BHFP of 2653.95psig, 2749.72psig, 2826.99psig, and 2930.11psig were obtaned for no water cut , and water cut of 25%, 50 % and 75%. Pressure gradient increases with water cut with a maximum at 75% water cut.

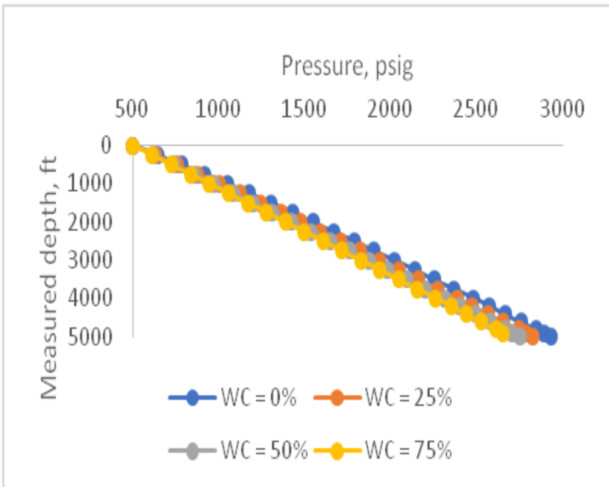

Figure 3 Pressure profile along the wellbore with no emulsion viscosity

3.3 Pressure gradient with emulsion viscosity

Figure 4 shows the result of the effect of emulsion viscosity on the pressure traverse along the wellbore for no water cut, water cut of 25%, 50% and 75%. With emulsion viscosity model, a bottom hole flowing pressure(BHFP) of 2988.8psig, 3030.73psig, 3325.24psig, 3357.58psig were obtained for different depth for no water cut and water cut of 25%, 50% and 75%. Emulsion viscosity model gave a higher BHFP for no water cut than 75% water cut for no emulsion viscosity.

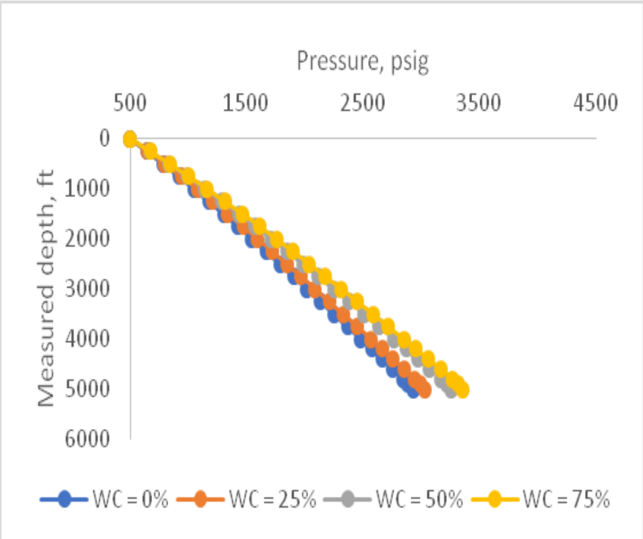

Figure 4 Pressure profile along the wellbore with emulsion model correction

3.4 Pressure gradient with and without emulsion viscosity for no water cut scenario

Figure 5 shows the pressure traverse along the wellbore for no water cut with and without emulsion viscosity.The no water-cut scenario have the same value for pressure gradient. This shows that at no water cut , there is no emulsion formation and the viscosity is that of the black oil correlation. For a no water cut case, a pressure of 2930.11psig existed at the bottomhole for both cases (with and without emulsion viscosity)

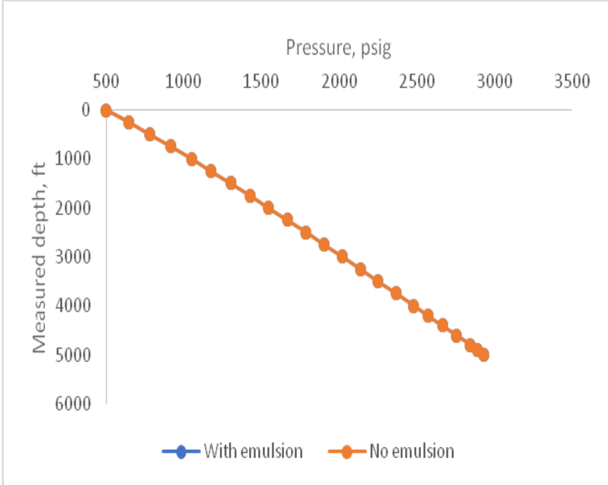

Figure 5 Pressure traverse for no water cut with and without emulsion correction

3.5 Pressure gradient with and without emulsion viscosity for water cut of 25%

The pressure traverse along the wellbore for water cut of 25% with and without emulsion viscosity is presented in figure 6. For a water cut of 25%, a pressure of 2826.99psig and 3030.73psig existed at the bottomhole for both cases (without and with emulsion viscosity). Pressure gradient is higher for case with emulsion viscosity than without emulsion viscosity as shown in figure 6. Water cut of 25% results in an increase in the bottom hole flowing pressure(BHFP) for case with emulsion and a decrease in the BHFP for case without emulsion compare to base case with no water cut.

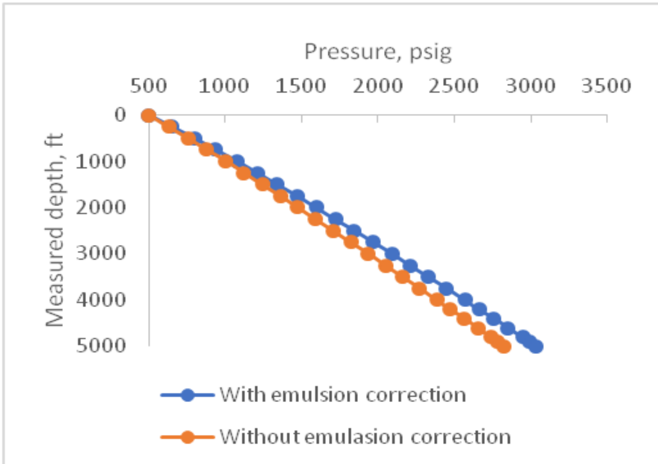

Figure 6 Pressure traverse for water cut of 25% with and without emulsion correction.

3.6 Pressure gradient with and without emulsion viscosity for water cut of 50%

The pressure traverse along the wellbore for water cut of 50% with and without emulsion viscosity correction is shown in figure 7. For a water cut of 50%, a pressure of 2749.72psig and 3257.74psig existed at the bottomhole for both cases (without and with emulsion viscosity). Similarly, there was an increase in pressure corresponding to increase in water cut which gave rise to increase in emulsion viscosity. Comparison of the base case with no water cut shows that there was a decrease in the BHFP for case without emulsion and an increase in BHFP for case with emulsion.

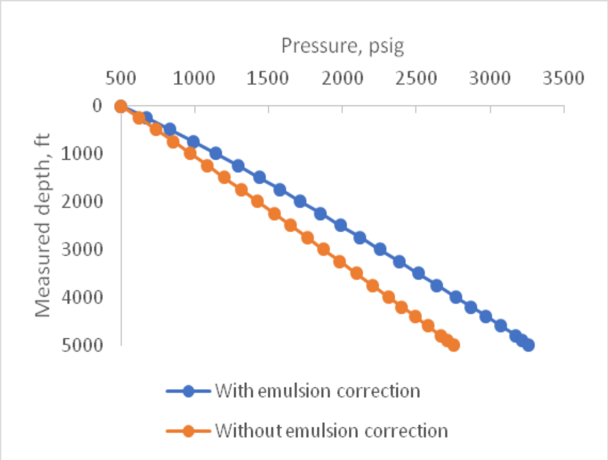

Figure 7 Pressure traverse for water cut of 50% with and without emulsion correction

3.7 Pressure gradient with and without emulsion viscosity for water cut of 75%

Figure 8 presents the pressure traverse along the wellbore for water cut of 75% with and without emulsion viscosity. Results show that for a water cut of 75%, a pressure of 2696.07psig and 3357.58psig existed at the bottomhole for both cases (without and with emulsion viscosity).There was a drastic pressure drop for 75% water cut resulting from emulsion viscosity increase. Water cut of 75% results in a drastic increase in the bottom hole flowing pressure(BHFP) for case with emulsion viscosity and a hgh decrease in the BHFP for case without emulsion viscosity compare to base case with no water cut.

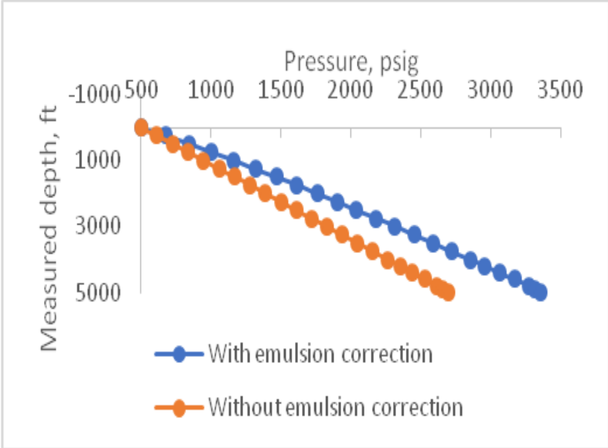

Figure 8 Pressure traverse for water cut of 75% with and without emulsion correction

Conclusions

In this work, the impact of increasing water cut on pressure gradient within the wellbore for with and without emulsion viscosity during oil production were investigated. The following conclusions were drawn from this study:

i. Pressure gradient increases as the water cut increases for case with emulsion viscosity
ii. The pressure gradient decreases with increase in water cut for case without emulsion viscosity
iii. The pressure gradient was the same for both with and without emulsion viscosity case
iv. There was a reduction of 8% in BHFP (without emulsion viscosity) and increase of 14.6% in BHFP(with emulsion viscosity) from the base case of no water cut to highest water cut of 75%.

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Conflicts of interest

There was no conflict of interest

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