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ADJUSTING TWO-PHASE FLOW CORRELATION TO INCLUDE RADIAL MASS TRANSFER EFFECTS

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Abstract. *Correlations to determine pressure drop and void fraction for two-phase flow are developed based on experimental data, however these data are rarely obtained in pipelines that receive radial inflow through wall perforations such as, for example, producer tubes in oil fields and gas. On the other hand, many studies have obtained correlations to calculate the friction factor in single-phase flows in this type of flow with radial inflow. In this way, this work aims to analyze the impacts of adjusting a correlation of calculation of fraction of void and head loss to consider the effects of acceleration and friction caused by radial influx. The methodology used to assess these impacts is to consider a case of a horizontal-well producing an oil reservoir and obtain the production results, in a simulator coupled with a simplified reservoir model, of the correlation and the same correlation modified to take into account the effects of radial inflow, taking as a reference value a second correlation obtained in experiments with this type of inflow. The results obtained showed that there was a significative difference between the correlation before and after the modification, and after the modification the correlation was much closer to the pressure results of the correlation obtained in experiments with inflow, although it has preserved the behavior of the liquid holdup of unmodified correlation.*

Keywords: *two-phase flow correlations, pressure drop, void fraction, radial influx.*

1. INTRODUCTION

In the past two decades horizontal wells proliferate in the petroleum industry Harris (2019). This type of wells permits a greater length of production zone and consequently to predict pressure drop in that zone is generally more important than in vertical wells were gravitational effects dominate. Even with this proliferation, there are few correlations of two-phase flow models that have been developed including the effects caused by the mass influx, this is probably due to the difficult availability of all the necessary apparatus to perform experiments.

Many authors developed single-phase models to consider the effects of wall mass transfer, as Siwon (1987); Asheim, Kolnes and Oudeman (1992); Su and Gudmundsson (1993); Yuan, Sarica and Brill (1996); Yalniz and Ozkan (2001); Firoozabadi *et al*. (2011); Zhang *et al*. (2014) and Yue *et al*. (2014). Wang *et al*. (2017) presented a model for two phase oil-water flow.

As the focus of this work are multiphase liquid-gas flows, the studies that presented models for this type of flow are of utmost importance. After an extensive literature review, only one experiment was found, performed by Ouyang (1998), which obtained data on multiphase flow with mass transfer through the wall. From these experiment Ouyang, Arbabi and Aziz (1998) originally presented a single-phase model, then Ouyang (1998) presented a mechanistic model and a homogeneous liquid-gas model, Ouyang and Aziz (2002) also presented an improved mechanistic model.

Although the existence of two models developed by the same author may seem satisfactory, these models may not suit the characteristics of the field being produced, while other models may better represent fluids in terms of both pressure drops in the vertical region and liquid holdup. Thus, changing a correlation already well established as consistent with the behavior of field fluids, so that it considers the effects that influx has on head loss, can be advantageous in terms of modeling.

In this work a modification in Beggs and Brill (1973) correlation for multiphase flow also will be utilized. The objective of this modification is to understand if it possible to improve classical pipe correlations in case of wall mass transfer flow and to present an alternative for vertical wellbore simulations. In order to do that, a well simulator that can utilize this correlation, the unmodified Beggs and Brill (1973) and both Ouyang (1998) correlations will be coupled with a reservoir model. This coupled model will perform simulations and the analysis of results will indicate how the model changes with radial mass inflow considerations.

2. BEGGS & BRILL (1973) MODIFICATION FOR RADIAL INFLOW OR OUTFLOW

The mechanistic multiphase correlation presented by Ouyang (1998) was developed for horizontal or slightly inclined flows, while the single-phase model presented in Ouyang, Arbabi and Aziz (1998) can be described as a modification in the acceleration term and in the expression for calculating the friction factor to account for wall mass transfer effects, which can be replicated for any other existing model. Based on that, it is possible to try modifying a largely used model for pressure drop calculations to consider wall effects on the main flow.

The initial calculation of the Beggs and Brill (1973) model aims to obtain the liquid hold-up and a flow pattern; these first steps are not altered by the modification proposed here. The first modification is for the frictional term; the original term as presented in Beggs and Brill (1973) is shown in Eq. 1.

$$\left(\frac{dp}{dx}\right)_{fric} = -\frac{f_{tp}\, G_m\, U_m}{2D} \tag{1}$$

Where U_m is the mixture velocity, G_m is calculated using Eq. 2 and f_{tp} using Eq. 3 where S is a factor developed by Beggs and Brill (1973).

$$G_m = (\rho_l\, U_{sl} + \rho_g\, U_{sg})A \tag{2}$$

$$f_{tp} = 4e^{S} F_{fanning}\left(Re_{tp}, D, \epsilon\right) \tag{3}$$

The modified frictional term presents two changes: U_m is substituted by U_{tp} and f_{tp} is calculated considering inflow/outflow effects. The modified term is presented in Eq. 4.

$$\left(\frac{dp}{dx}\right)_{fric} = -\frac{f_{tp}\, G_{tp}\, U_{tp}}{2D} = -\frac{f_{tp}\, \rho_{tp}\, U_{tp}^2}{2D} \tag{4}$$

Where U_{tp} and ρ_{tp} are respectively the two-phase flow velocity and two-phase flow density, both proposed by Ouyang (1998) and f_{tp} is calculated by Eq. 5.

$$f_{tp} = 4e^{S} F_{ouyang}\left(Re_{tp}, R_w, D, \epsilon\right) \tag{5}$$

The original acceleration term is calculated as in Eq. 6. Beggs and Brill (1973) chose to assume that liquid acceleration is small compared with gas acceleration; the authors also made some considerations assuming ρ_g calculated by engineering gas law, in order to avoid that these considerations influence the comparison between original and modified models; the original acceleration term (Eq. 6) will be substituted using Eq. 7.

$$\left(\frac{dp}{dx}\right)_{acc} = -\frac{\rho_{tp}\, U_m\, G_g}{\rho_g^2}\frac{d\rho_g}{dx} \tag{6}$$

$$\left(\frac{dp}{dx}\right)_{acc} = -\rho_{tp}\, U_m\, \frac{dU_m}{dx} \tag{7}$$

The derivative of U_m with respect to x will be numerically determined considering the pressure drop in a segment. The acceleration term utilized by the modified model\, assuming inflow/outflow and taking into account that ρ_{tp} does not change significantly in the segment, it can be calculated by Eq. 8 or by Eq. 9; however, as recommended in Ouyang (1998) homogenous model, it will be calculated using a weighted mean.

$$\left(\frac{dp}{dx}\right)_{acc,1} = -\rho_{tp}\, U_m\, \frac{dU_{tp}}{dx} - \rho_{tp}\, U_{tp}\, \frac{dU_m}{dx} = -\frac{\rho_{tp}\left(U_m\, q_{Itp} + U_{tp}\, q_{Im}\right)}{A} \tag{8}$$

$$\left(\frac{dp}{dx}\right)_{acc,2} = -2\rho_{tp}\, U_{tp}\, \frac{dU_{tp}}{dx} = -\frac{2\rho_{tp}\, U_{tp}\, q_{I\,tp}}{A} \tag{9}$$

The modified Beggs and Brill (1973) was presented since the modifications are made by the authors of this work, the description of the other models that will be utilized can be found in the original works. Gravitational terms were not analyzed here, since only horizontal case will be simulated.

3. TWO-PHASE RESERVOIR WITH SOLUTION GAS DRIVE AS PRODUCTION MECHANISM

In this work a simplified reservoir capable of simulate reservoir with solution gas drive as production mechanism will be utilized, the aim of utilize this model is to guarantee two-phase flow in wellbore. The simplified reservoir model is formed of two parts. The first part is responsible for calculating the energy/pressure loss in the reservoir while the second part is responsible for calculating responsible for calculating the oil flow for a given reservoir condition.

Reservoir depletion simulation with material balance method will be utilized. More about this technique can be found in Economides et al (2013). Here the focus is for a reservoir that produces oil and gas and, as such, we will utilize a calculation method for solution gas drive reservoirs as presented in Economides et al (2013). Solution gas drive reservoirs are defined as reservoirs with no initial gas cap but rapidly goes below the bubble-point pressure after production commences according to Economides et al (2013). The material balance method calculates GOR and complementary the Permadi Model will estimate the oil flowrate.

3.1 Permadi Model for Semisteady-State Flow

In Permadi (1993) and Permadi (1995) the author presented a model to estimate the oil flow rate for horizontal well. The advantage of this method in comparison with others is the simplicity. But this simplicity comes with limitations. In this work the model will be utilized to test the correlations for horizontal wells, so the reservoir model cannot be considered complete (it is just capable of representing some reservoirs).

Equation 10 presents the concept of productivity as a relation between pressure drawdown and oil flowrate:

$$J_h = \frac{Q_o}{(\overline{p_r} - \overline{PWB})} \tag{10}$$

When there is no pressure support, the reservoir presents a semisteady-state flow; the Permadi model to estimate J_h in this situation is presented in equation 11.

$$J_h = \frac{0.00708\ k_h\ h\ L}{\mu_o B_o \left\{0.523\left(X_e - Y_e\sqrt{\frac{h}{L}}\right) + \beta_e h\left[\ln\left(\frac{Y_e}{2r_w}\sqrt{\frac{h}{L}}\right) - \frac{3}{4} + S\right]\right\}} \tag{11}$$

Where the horizontal permeability and the anisotropy factor (β_e) are calculated according Permadi (1993). Figure 2 presents the reservoir model in which Permadi (1993) developed the productivity equation. This model is restricted but good enough for the purpose of this work.

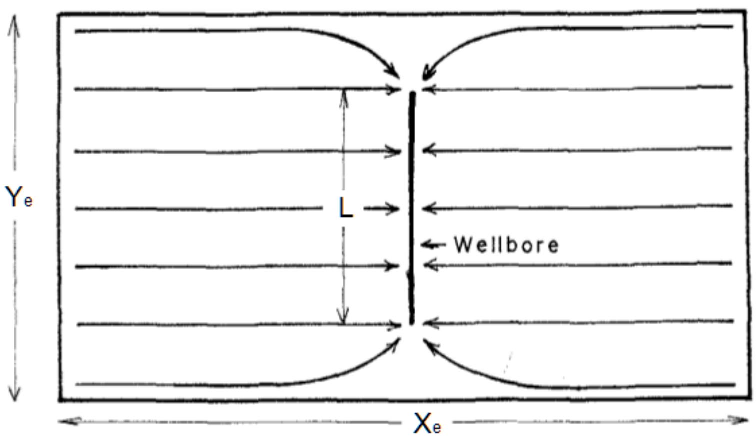

Figure 1. Plan View of Reservoir Physical Model utilized to obtain Permadi Model.
Source: Adapted from Permadi (1993).

4. COUPLING STRATEGY

To simulate production situations a coupling strategy was developed, this strategy is presented in Fig. 2. The reservoir model based on the material balance method utilizes pressure steps; as such, this algorithm starts setting a variation in the reservoir pressure to finally obtain reservoir GOR. The Permadi Model is applied to the main loop to calculate Q_o for the reservoir pressure at the beginning of the depletion step; after that, wellbore pressure is calculated using Q_o, GOR and the bottom-hole pressure defined in program. The PWB value obtained is compared with the value utilized to obtain Q_o; if the loop converges the time of the step is obtained, else Permadi Model is recalculated using the new PWB.

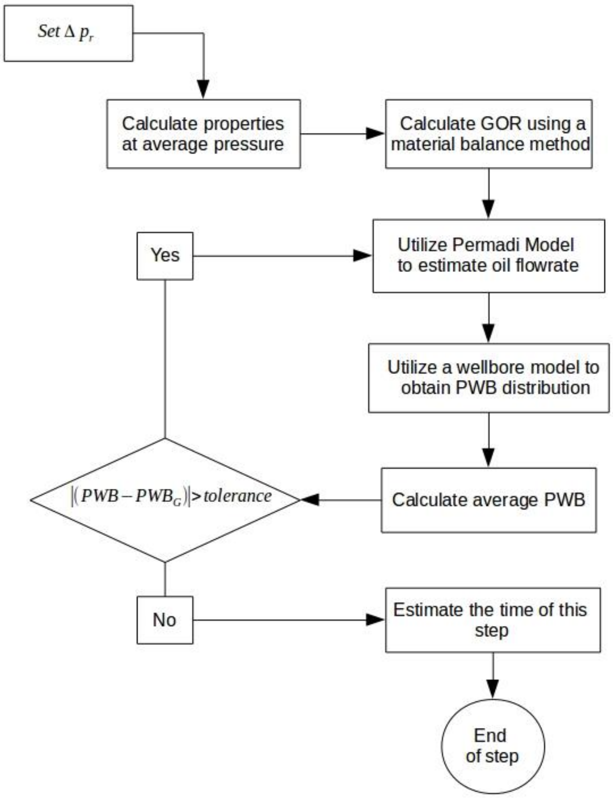

Figure 2. Algorithm for horizontal coupling.

5. SIMULATION CASES

To compare the four well models 17 simulation cases were simulated. The simulation cases are based on the two reservoirs that are presented in Table 2 with characteristics of the well. The four variables considered for each case are:

- The length of the wellbore (*L*);
- The reservoir horizontal permeability (k_h);
- The difference of pressure between the mean pressure of the reservoir and the pressure at the well heel (*DPWB*);
- The wellbore radius (r_w).

The figure presents an illustration of a horizontal well. In this work, the non-horizontal region of the well will not be considered; the pressure drop difference between reservoir and well heel will be assumed constant during the production time. Table 1 presents all the simulations cases performed to obtain the results shown in the next section. The depletion step utilized in every case is 100 psi.

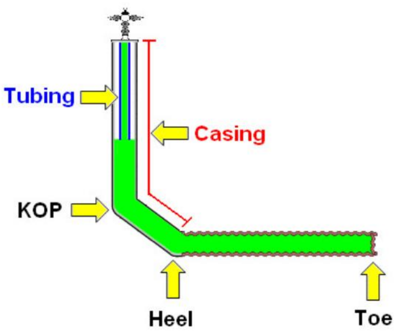

Figure 3. Horizontal well positions nomenclature
Source: Fekete (2020)

Table 1- Simulation Cases.

CASE	RESERVOIR	*L* (*ft*)	k_h (*mD*)	DPWB (*psi*)	r_w (*ft*)
1	1	200	100	2000	0.1875
2	1	200	100	2000	0.4060
3	1	200	100	2200	0.1875
4	1	200	100	2200	0.4060
5	1	200	200	2000	0.1875
6	1	200	200	2000	0.4060
7	1	200	200	2200	0.1875
8	1	200	200	2200	0.4060
9	1	600	100	2000	0.1875
10	1	600	100	2000	0.4060
11	1	600	100	2200	0.1875
12	1	600	100	2200	0.4060
13	1	600	200	2000	0.1875
14	1	600	200	2000	0.4060
15	1	600	200	2200	0.1875
16	1	600	200	2200	0.4060
17	2	4000	100	200	0.1666

Table 2- Characterization of Reservoirs 1 and 2 and Wellbore

RESERVOIR 1 CHARACTERISTICS		RESERVOIR 2 CHARACTERISTICS	
X_e	744 *ft*	X_e	5000 *ft*
Y_e	744 *ft*	Y_e	5000 *ft*
h	744 *ft*	**h**	100 *ft*
p_i	4336 *psi*	p_i	4336 *psi*
p_b	4336 *psi*	p_b	4336 *psi*
ϕ	0.21	ϕ	0.21
S_w	0.3	S_w	0.3
k_v	10 mD	k_v	100 mD
WELLBORE CHARACTERISTICS			
Perforation diameter		0.18 *in*	
Perforation density		10 *shots/ft*	
Inflow angle to the horizontal		45°	
Relative roughness		0.0002	

6. RESULTS

The simulations cases presented previously will be carried out using the coupling strategy shown in section 4 to estimate possible advantages of considering radial mass transfer using Beggs and Brill(1973). The first simulation was performed for Case 1 in Table 1; the results obtained for pressure drop over time are presented in Figure 4:

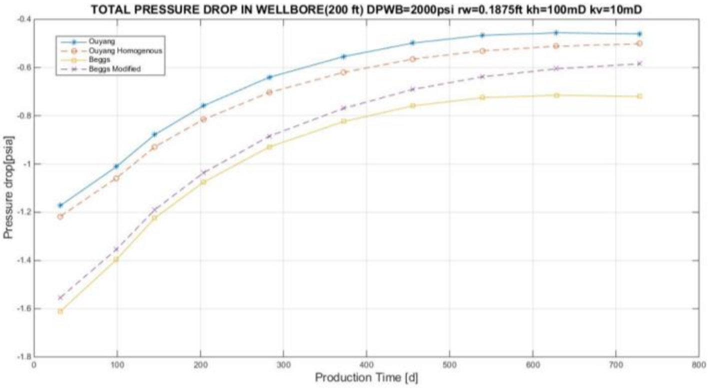

Figure 4. Pressure Drop in Wellbore for Case 1

Since Ouyang (1998) mechanistic model was created for this type of flow, it will be utilized as a reference value for comparison purposes. It is clear in the figure above that Ouyang (1998) homogeneous model obtained the closest results for pressure in each step of the simulation, but Beggs and Brill(1973) modified model obtained better results than the original correlation, which is an evidence of an improvement. Figure 5 presents the liquid hold-up for the first step in Case 1:

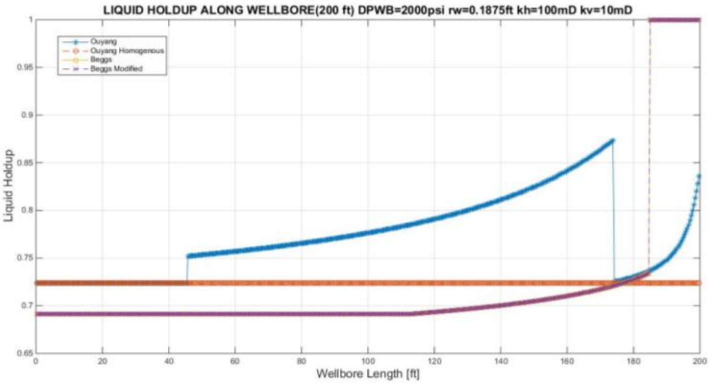

Figure 5. Liquid holdup in Wellbore for the first depletion step - Case 1

The liquid holdup for Beggs and Brill (1973) modified model presents the same results as the original correlation; the homogeneous model presents a constant value for liquid holdup as the inflow is made equal along the length of wellbore. Ouyang (1998) mechanistic model shows discontinuities caused by pattern prediction and due to these discontinuities the results obtained are sometimes closer to the homogeneous model and sometimes closer to Beggs and Brill (1973) results.

Cases 2 to 8 neither add any new information to the analysis nor enrich the discussion of the results and so they are not explicitly presented or discussed. Case 9 presents an expressive pressure drop. Figure 6 shows the pressure drop calculated by each correlation in each depletion step:

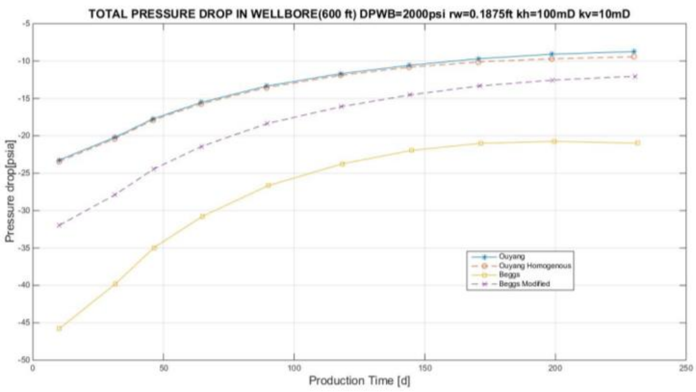

Figure 6 - Pressure Drop in Wellbore for Case 9.

For this case, the Beggs and Brill(1973) modified model predicts significant less pressure drop than the original model, and this difference, that is caused by the reduction in friction losses, reduces the gap between this model and

Ouyang(1998) mechanistic model. The homogeneous model proposed by Ouyang (1998) presents the nearest results for every depletion step. For liquid holdup, the behavior predicted by each correlation is very similar to that presented in Cases 1 and 2, except that in case 9 it is possible to observe a small difference between Beggs and Brill(1973) modified and unmodified models. Figure 7 presents the behavior of liquid holdup for first depletion step in each model.

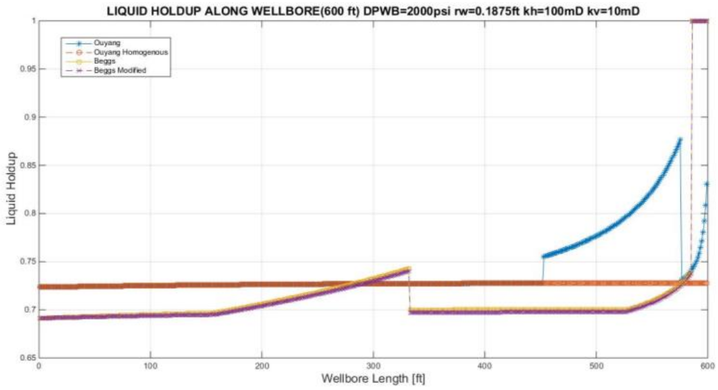

Figure 7. Liquid holdup in Wellbore for the first depletion step - Case 9.

Case 16 brings new information to the analysis; in this case, the pressure drop estimated by Ouyang(1998) mechanistic model in the last depletion step calculated is closer to the estimate obtained with the Beggs and Brill(1973) modified model than to the estimative derived from the homogeneous model, as presented in Figure 8. The reasons behind it can be investigated in Figures 9 and 10. In the former, the liquid holdup estimated by the mechanistic model indicates a dominance of stratified flow along the wellbore, but the flow pattern close to the heel is intermittent and the liquid holdup increases. Figure 10 presents the pressure along the wellbore in the last depletion step, observing Ouyang(1998) mechanistic results and integrating them with the information of Figure 9 it is possible to identify that for intermittent flow the pressure drop is underestimated in relation to other models. For stratified flow, the pressure drop estimated is greater than the one estimated from the Beggs and Brill(1973) modified model, although the sum of losses in each pattern results in a total value that is close to the one obtained by the modified model.

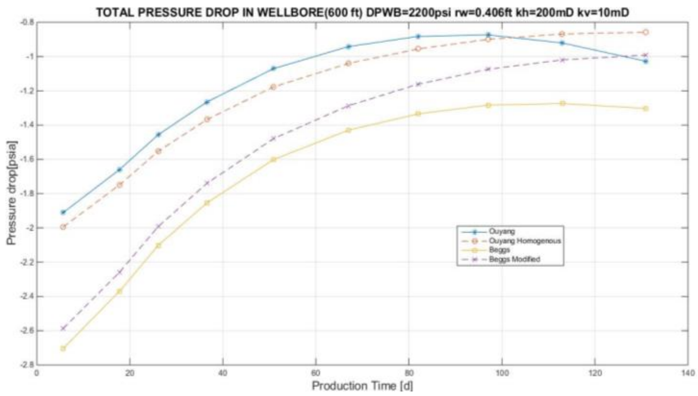

Figure 8. Pressure drop in wellbore for Case 16.

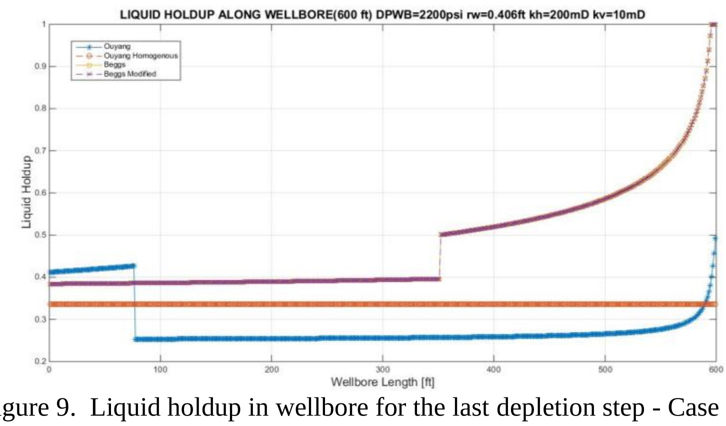

Figure 9. Liquid holdup in wellbore for the last depletion step - Case 16.

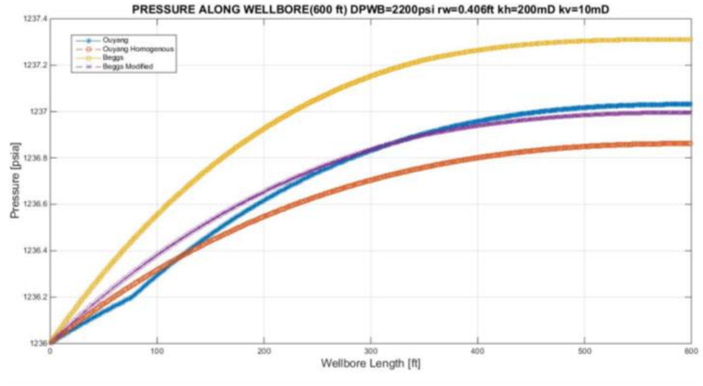

Figure 10. Pressure in wellbore for the last depletion step - Case 16.

Case 17 is especially different because the wellbore is much longer; the results obtained for pressure drop are presented in figure 11: the homogeneous model shows results closer to the mechanistic model, but the modified model was significantly better than the original Beggs and Brill(1973) correlation. For the initial steps, with greater flow rates, the pressure drop is estimated to be nearly equal for the three models that consider inflow effects.

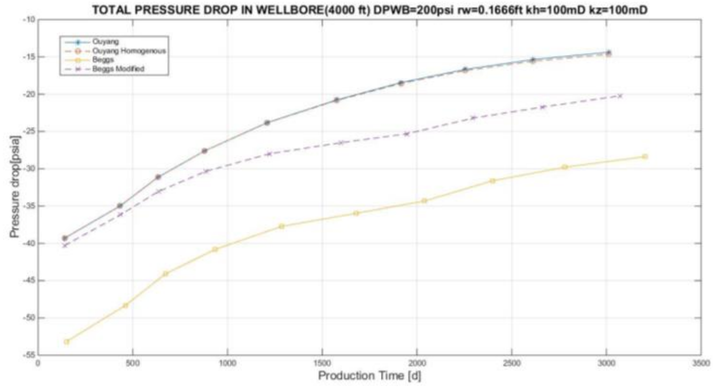

Figure 11. Pressure Drop in Wellbore for Case 17.

Figures 12 permits a deeper investigation on the factors behind this small difference. Results for liquid holdup are in the small range compared to other cases presented. There is no significant difference on the friction/acceleration losses ratio between the first step and the last one when the results are not so close; so, the main reason behind that small gap is the small range of liquid holdup that induces a similar estimate for mixture properties and consequently a similar estimate for pressure drop. With the increase in the amount of gas in the wellbore, liquid holdup range raises, and the pressure drop estimated by each correlation eventually differs from the results of other models.

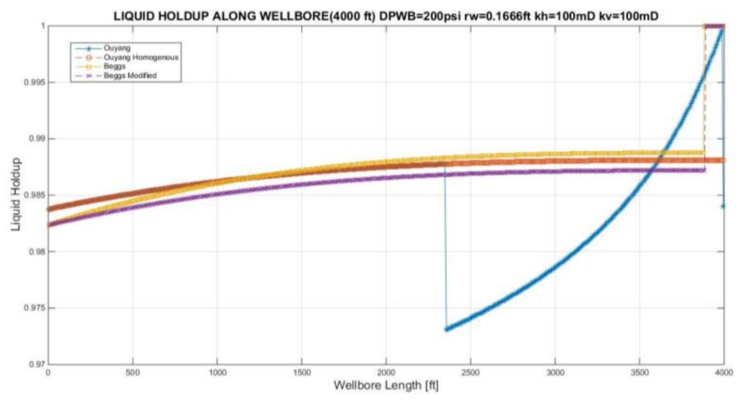

Figure 12. Liquid holdup in wellbore for the first depletion step - Case 17.

A final observation can be made comparing all the total pressure drops after a depletion step; this comparison is presented in figure 13. Using Ouyang (1998) mechanistic model as comparation basis, it is possible to notice that for low pressure drops (generally associated with low flow rates) the original Beggs and Brill (1973) model estimates smaller losses than the mechanistic model. However, when the flow rate increases, that relation is reverted. Ouyang(1998) estimate greater losses for almost every depletion step, but it generally presents results that do not deviate much from the 25% difference range for the reference model; conversely, the original Beggs and Brill(1973) deviate significantly, more than 25% for losses above 5 psi. The homogenous model is consistent with the original Ouyang model.

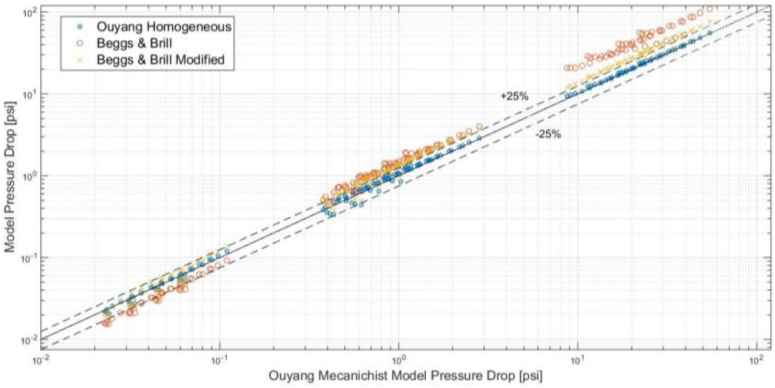

Figure 13. Total Pressure Drop estimated for each depletion step in every simulation case.

7. CONCLUSION

A simplified coupling reservoir-well coupling method was implemented to perform horizontal well simulations. The horizontal well simulations were performed in order to measure the impact of adapting the correlation developed by Beggs and Brill (1973) to consider radial influx; this correlation was compared with the modified model developed by this work and with the mechanistic and homogenous models presented by Ouyang (1998) as both were developed using radial influx as reference experiments.

The results showed that, in general, Modified Beggs and Brill (1973) correlation pressure drop calculation was more consonant with Ouyang (1998) models than with the original correlation, although liquid holdup results were very similar with or without modification. This indicates that it is possible to adapt a correlation to consider influx effects in the main without significant impacts in holdup prediction.

8. ACKNOWLEDGEMENTS

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