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Research Article

Modeling and Simulation of Multiphase System in Production Well using WellFlo^R Software

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Abstract

Modeling and simulation of crude oil-gas production well was carried out with Wellflo^R software using designated parameters. Effect of tubing diameter on the operating point was investigated. 3.42 inch tubing gave optimum operating point. The tubing was further evaluated for minimum flowing bottom hole pressure (FBHP) and depth-pressure gradient using different correlations. The result revealed that the production was carried out at 2503.51psia close to the minimum FBHP. Performance all the correlation used showed good agreement. However, Gregory correlation seems to be the best. The bottom well pressure predicted by this model gave the FBHP value of 2374psia, the closest to minimum FBHP (2475psia) required for stable production. Effect of artificial lift was also evaluated and the result compared with the natural drive. The use of artificial lift enhanced more production under the same pipe condition with the natural drive. Finally, the mechanistic models have shown capability of given realistic predictions of multiphase flow in pipes.

Keywords: *Modeling; Simulation; oil and gas; Production well; WellFlo^R*

1. Introduction

Multiphase flows are found in most engineering systems for deliberate transfer of large quantities of heat over a small temperature differences. It also consists of Unavoidable phase changes that may result in a process or processes. Both situations have intense effect on system performance and characteristics in terms of pressure drops, heat transfer rates and flow stabilities. This in turn affects the system reliability and makes it more difficult. In order to achieve the design goals, the condition needed to be account for in most efficient way. Among all the multiphase systems, two phase flow seem to be the most common (Faghri and Zhang, 2006).Two phase flow is an interactive flow of two distinct phases in which each phase represent mass or volume of matter with shared boundaries in a channel. Liquid-gas system is the most frequent type of two phase flow in industries and it is made up of deformable interface where mass and heat transfer occur and can vary over a wide range. These interfacial distributions are referred to as flow regimes or flow patterns (Faghri and Zhang, 2006).

There are many flow regimes and flow regime transition in straight vertical and horizontal tubes. In a vertical up ward cocurrent flow, the system appear to be symmetrical around circumferential direction due to gravitational force and the regimes are classify as bubbly, slug or plug, churn, annular and wispy annular flow as shown in Figure 1 below (Angeli and Hewitt, 2000; Moreno and Thome, 2007).

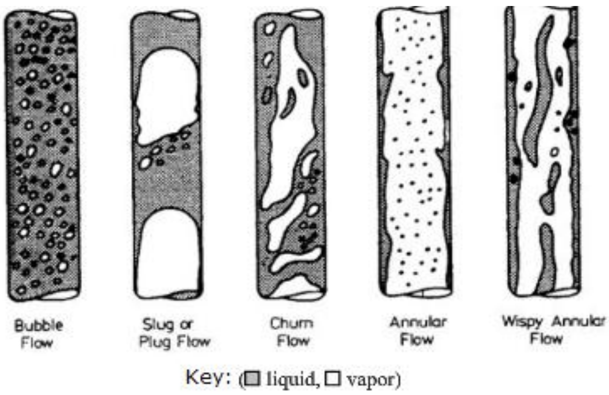

Figure 1: Flow regimes in vertical upward cocurrent two-phase flow (Angeli and Hewitt, 2000)

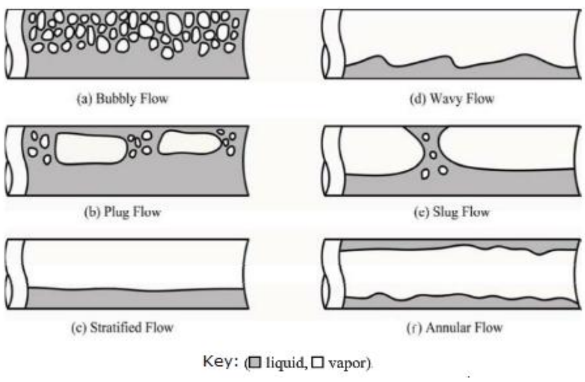

Figure 2: Flow regimes in horizontal two-phase flow (Faghri and Zhang, 2006)

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On the other hand, the horizontal cocurrent flow has different flow regimes compare to the vertical flow due to the gravitational force acting perpendicular to the direction of flow and they include dispersed bubble, plug, stratified, stratified wavy, slug, and annular-dispersed flow (Angeli and Hewitt, 2000; Faghri and Zhang, 2006; Moreno and Thome, 2007) as presented in Figure 2.

Since characteristics of two-phase flow vary from regime to regime, various methods are used for prediction of pressure drop and heat transfer. This includes analytical and numerical models, and the use of experimental and operational data.

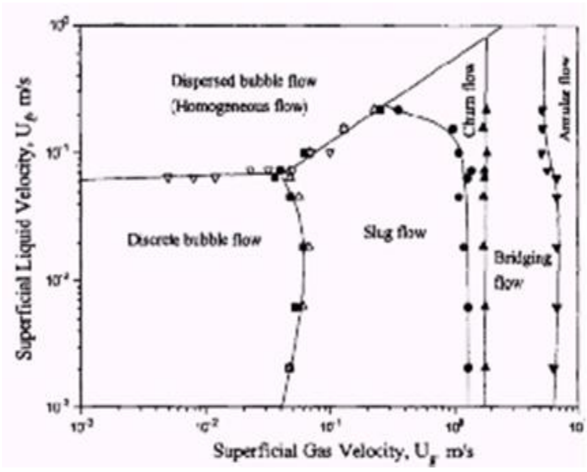


Figure 3: Flow regime map for vertical upward cocurrent two-phase flow (Zhang, *et al*. 1997)

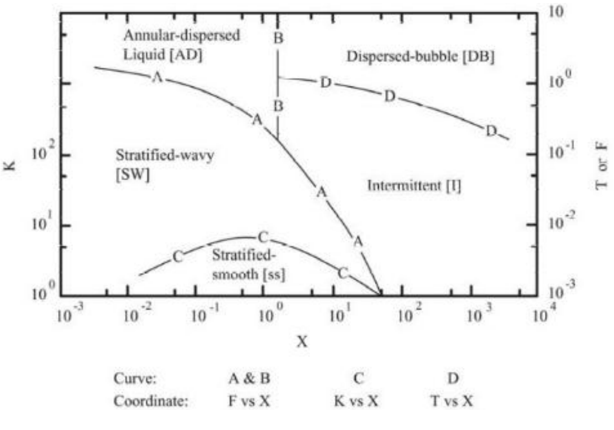


Figure 4: Flow Regime map for horizontal two-phase flow (Taitel and Dukler, 1976)

The former uses principle of mass and energy balances for a simple boundary and steady state conditions. For more complex system, numerical approach is employed base on physical concept. The later has been transformed to simple diagrams call flow maps which provide information about flow rate and the operating parameters (Faghri and Zhang, 2006). The maps are generally presented in terms of liquid and gas superficial velocities or in form of generalized liquid and gas flow parameters with each regime clearly spelt out. The lines between the regimes correspond to a transition state and more often than not vital in practical applications as shown in Figures 3 and 4.

1.1 WellFlo^R

WellFlo^R is a powerful application package for designing, modeling, optimizing and troubleshooting natural and artificial lifted oil and gas wells. It uses nodal analysis techniques to provide information on reservoir inflow, well tubing and surface pipeline flow for any reservoir fluid (Weatherford, 2012). Once the appropriate data is feed in, desired result is produced depending on parameter of interest.

This objective of this study was to carry out modeling and simulation of oil and gas production well using WellFlo^R based on experimental data.

2. Methodology

The steps used in running the software is given in the flow diagram below (Figure 5) using the data in Table 1. Single case run was first carried out to establish production range from the inflow performance relationships (IPR) curve (bottom hole pressure versus total liquid volume flow). This initial run was then used to evaluate other process variable such pipe diameter, comparison between different correlations and the effect of artificial lift.

Table 1: WellFlo^R data (Azzopardi, 2012)

Parameter	Value	Unit
Skin	0	
Reservoir Pressure	5000	psia
Reservoir Temperature	200	F
Permeability	36	md
Pay thickness	44	ft
Wellbore radius	3.5	in
Drainage area	160	acres
Perforation interval	44	ft
Perforation shot density	4	shots/ft
Tunnel diameter	0.35	in
Tunnel length	6	in
kc/kf	0.5	
Water cut	15	%
GOR	300	scf/STBO
Oil gravity	32	API
Gas specific gravity	0.65	
Water specific gravity	1.07	
Wellhead pressure	100	psig
Perforation top	8650	ft
Wellhead temperature	70	F
Casing ID	5.921	in
Annulus fill	water@	68F
Well orientation	Vertical	

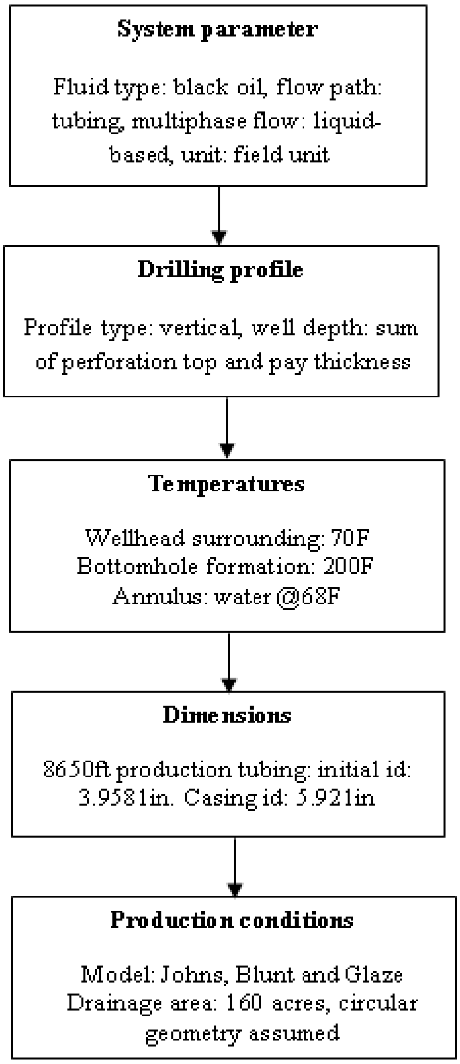
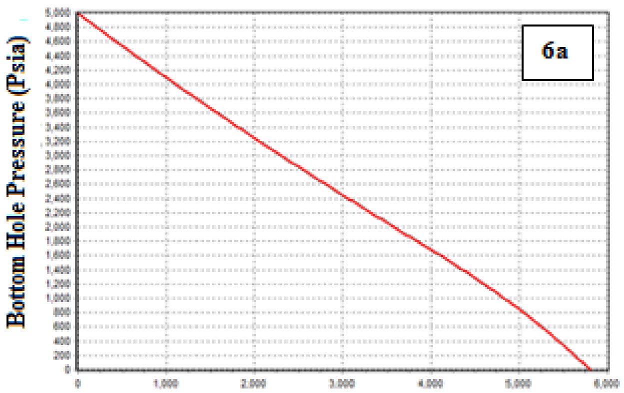


Figure 5: Flow chart for running Wellflo[R] software

3. Results and Discussions

Result of initial single case run gave production range of 0-5800bbl/day as on the IPR curve (Figure 6a). The flow regime appeared at interface between froth and dispersed bobble (Figure 6b) with liquid and gas superficial velocities at 2.275 and 14.376 ft/sec respectively. Other properties of the fluid such as mixture velocity and density were found to be 16.56ft/sec and 7.64lb/ft^3 correspondly.



Bottom Hole Total Volumetric Flow Rate (bbl/day)

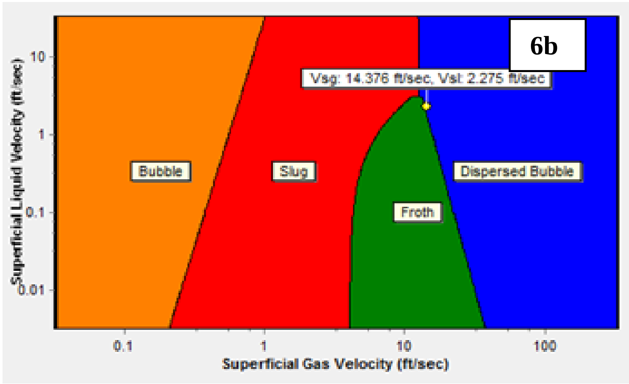


Figure 6: IPR curve (a) and flow map (b) for the single case run

Effect of tubing diameter on the operating point was evaluated using 2-4.4 inch tubing. As the tubing (ID) diameter increases, the pressure loss is reduced and the production rate increased on till a point is reached where any further increase in diameter produce no significant increase in production. The increase in production rate was as result of decrease in frictional pressure losses. Here, the gravitational and acceleration pressure components have little effect on the process. Beyond a certain point, a transition occur which led to decrease in production with tubing diameter. This may be attributed to increase in frictional pressure loss due to high flow rate. This trend is expected which in accordance to the work of Hernandez-Pere, *et.al.* (2010) on multiphase flow in vertical pipes. This shows that in multiphase flow, bigger tubing does not always lead to reduction in pressure losses. Figure 7 shows IPR and tubing performance curve for the selected tubing diameters and the operating points are display in Table 2 below.

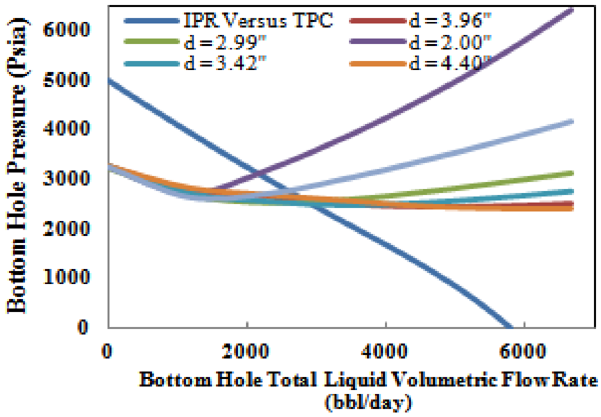


Figure 7: Plot of IPR against TPC for different selected tubing diameters

Furthermore, Increase in tubing diameter increases the bottom hole flow rate. This trend continues till an optimum point, the maximum obtainable flow rate under the natural drive and thereafter leads to an inverse relation. The reduction was as a result of pressure drop due to increase in fluid superficial velocity. This indicates that in order to increase the flow rate, the bottomhole pressure must be decreased so as to increase the drawdown pressure. Thus, the greater the drawdown, the greater the flow. This relation is represented in Figure 8.

Table 2: Operating points for different selected tubing diameters

S/No	Operating point		Tubing diameter (inch)	
	Bottom hole pressure (psia)	Volumetric flow rate (bbl/day)	ID	OD
1	3095.03	2182.48	2.00	2.38
2	2735.19	2616.38	2.44	2.96
3	2526.13	2875.43	2.99	3.50
4	2503.51	2924.38	3.42	3.90
5	2530.41	2866.18	3.96	4.50
6	2587.11	2804.19	4.40	5.03

Tubing selection was carried out by considering optimum production, erosion values and the type of flow regime. From the result obtained, tubing with 3.42inch internal diameter gave maximum flow rate. The corresponding flow regime was dispersed bubble with erosion value (C-value) of 49 (Table 3). Although 3.96 inch tubing has lower C-value and give the same flow regime but its production rate was found to be about 58 barrels lower than the chosen tubing. This difference in production rate is more pronounced compare to the difference in the C-values which is only 3 lower than the chosen pipe. This indicates that both pipes will have almost the same life expectancy and thus the production rate remain the yardstick for the selection.

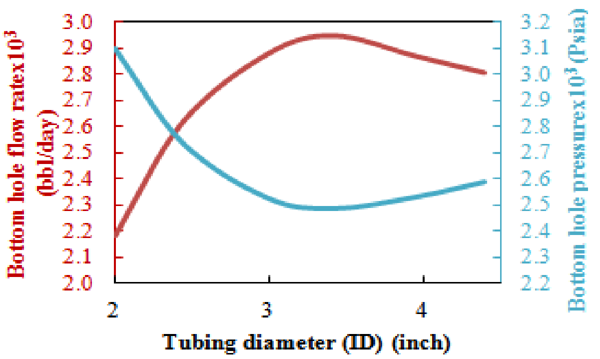


Figure 8: Plot of bottom hole flow rate and bottom hole pressure against tubing diameter

Table 3: Tubing diameter and flow regime with corresponding erosion values

Tubing diameter ID (inch)	Flow regime	Erosion value
2.00	Dispersed Bubble	71
2.44	Dispersed Bubble	97
2.99	Dispersed Bubble	64
3.42	**Dispersed Bubble**	**49**
3.96	Dispersed Bubble	46
4.40	Froth	42

Generally, a plot of flowing bottom hole pressure (FBHP) provide information on the minimum FBHP required to achieve maximum production and also to ascertain whether the production is done in a stable region or not. For selected tubing diameter the production was carried out at pressure of 2503.51psia (Table 2) which is above the minimum FBHP of 2475psia (Figure 9). This indicates an unstable production and must be avoided to eliminate problems of cyclic heading or surging by producing above 3500bbl/day. Increase in gas-oil ratio may be an option to address the problem. However, this may be a shortcoming of the modeling tool since multiphase flow correlations are developed based on stabilized flowing well data, correlation might have been extended beyond or below its range of validity.

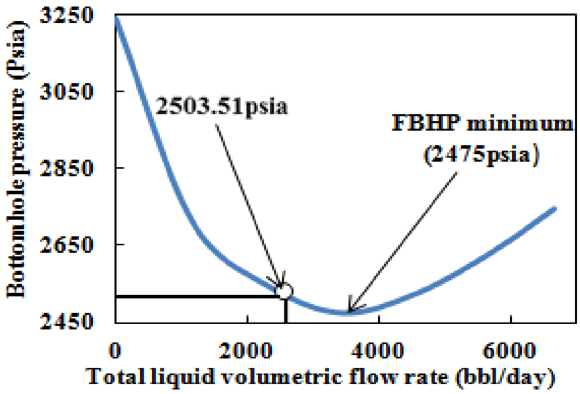


Figure 9: Plot of FBHP versus flow rate for the selected tubing diameter

In order to evaluate the temperature gradient within the wellbore, a plot of flowing wellhead temperature (FWHT) and total liquid volumetric flow rate is required (Figure 10). The result shows that the tubing FWHT is 151^{o}F. The lower flow rate recorded at lower at lower wellhead temperature may be due to effect of fluid density and viscosity. However, the pressure drops obtained were not very sensitive to small changes of this parameter.

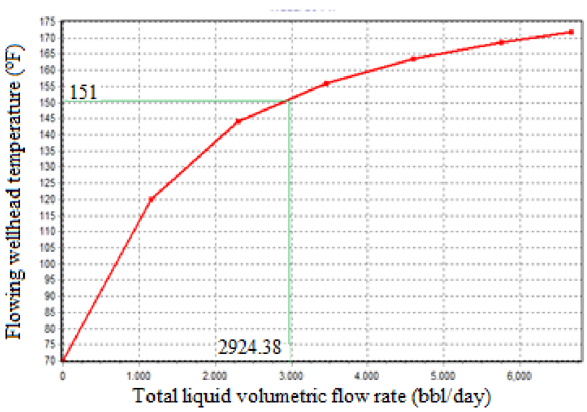


Figure 10: Plot of FWHT versus flow rate for the selected tubing diameter

Pressure variation over the depth was evaluated based on the liquid flow and the gas-oil ratio using Ansari, Aziz and Gregory correlations for the selected tubing. The correlations show good agreement with one another which make the curves overlap, showing a common characteristics throughout the plot (Figure 11). However, Gregory seems to be the best. The bottomhole pressure predicted by this model gives the closest value (2374psia) to minimum FBHP (2475psia) required for stable production. This may be due its ability to handle both steady state and dynamic qualities of the multiphase cases.

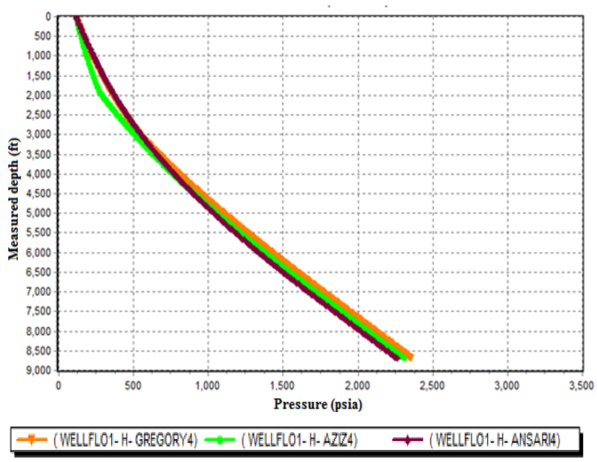


Figure 11: Plot of Pressure variation with depth for Ansari, Aziz and Gregory correlations

The operating point of Ansari flow was in slug regime while other correlations were in annular mist regime as shown in the flow maps below. This characteristic is due to increase in bubble sizes brought about by increasing gas velocity. Generally, the slug flow regime is undesirable in oil industry as it causes variation in density of the lifted fluid which exerts a backpressure on the formation and decreases the flow. This in turn results to fluctuations in the flow rate of oil and gas arriving the receiving equipment such as separators and slug-catchers thereby undermining the effectiveness of the equipment. In addition, the fluctuation also results in highly-unsteady loading on the tubing, piping system and processing equipment, which can cause catastrophic failure.

Effect of artificial gas lift was investigated with respect to tubing diameter. Generally, artificial gas lift describes the methods in which gas is used to increase oil well production. Natural gas can also be injected into the well to lift the oil artificially. The natural gas makes oil in the wellbore column much lighter in weight. As the liquid column become lighter, it exerts less pressure on the bottom of the well. With the pressure lower at the bottom, the pressure remaining in the reservoir becomes sufficient to push reservoir fluids to the surface through the tubing. As much as gas lift enhances production, care must be taken to prevent too much injection as this can be detrimental to the process and cause a decline in production as a result of frictional pressure drop (API, 1994).

Effect of artificial gas lift for various tubing diameters is e presented in Figure 13. For the diameters investigated, the liquid flow rates were higher than that of natural drive condition but have the same flow regime (dispersed bobble). 3.42 tubing also gave highest volumetric flow (4112.38bbl/day) and lowest bottomhole pressure (1600psia).

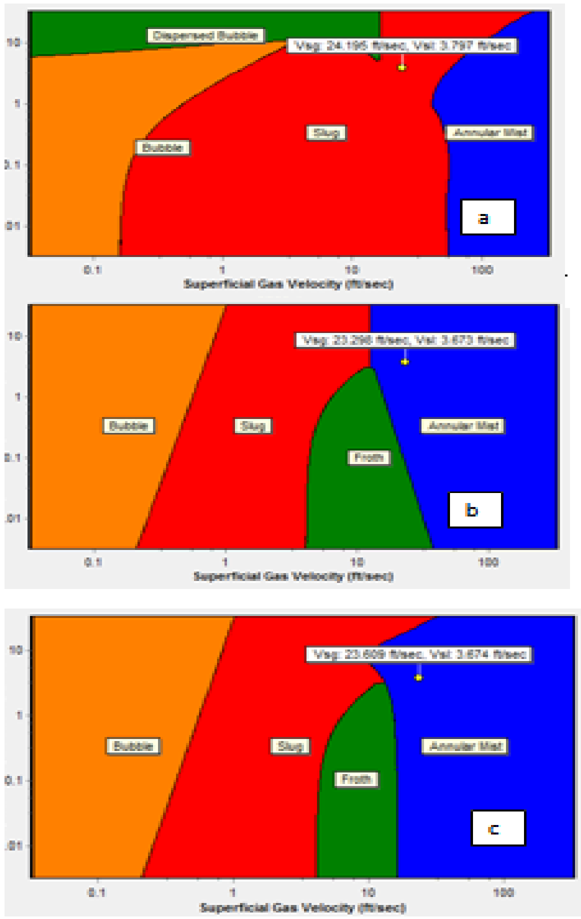


Figure 12: Flow map (a) Ansari, (b) Aziz, (c) Gregory

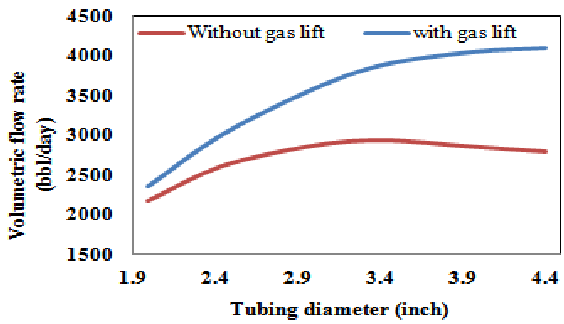


Figure 13: Plot of flow rate against tubing diameter with and without gas-lift

Conclusion

Modeling and simulation of oil-gas well was successfully carried out with Wellflo^R using designated parameters. Different tubing diameters were evaluated with respect to production rate and 3.42 inch (internal diameter) gave optimum operating point. Comparison between different correlations showed good agreement. Gregory correlation seems to be the best as bottom well pressure predicted using this model gave the flowing bottom hole pressure (FBHP) closest to the minimum value required for stable production. The use of artificial lift enhanced more production under the same pipe condition with the natural drive.

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