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Study of effective parameters on liquid accumulation in the gas wells

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ABSTRACT: Oil has an important role in world economy. Increasing global demand and decreasing hydrocarbon resources is an emphasis on reliable production of oil based on technical limits. Also many of oil fields in the world are getting mature and their production rate reduces through time. By enhancing hydrocarbon production, reservoir and wellbore pressure decreases. More pressure reduction will make reservoir unable to lift fluids to the surface. In gas reservoirs, by pressure reduction due to production will make liquids which consist of water and gas condensates to load in well and causes serious problems for production. Liquid loading in well causes multiple problems in production and well test data analysis. So it is necessary to investigate causes and phenomena related to this subject. In this study, effective factors in liquid loading is selected using literature then the parameters effectiveness on liquid loading and well production is investigated by simulation. Results showed after 4000 days of production, liquid production rate reduces significantly and the maximum recovery factor is 26%. Tubing diameter and wellhead pressure are selected as the two effective parameters on liquid loading and results showed by increasing tubing diameter and reducing wellhead pressure, recovery factor increases. The maximum recovery factor will happen at 3.5” tubing diameter and 350 psi of wellhead pressure.

***Keywords*:** Tubing Diameter, Overhead Pressure, Removal of Liquids, Gases Well, Simulation.

INTRODUCTION

Determination of the appropriate flow rate in a gas well, which leads to continuous production of fluid from the well and also prevents the accumulation of fluid in the well column, is one of the most important topics in the operation and production of gas wells. For example, if the well is closed, fluid accumulation in the well column leads to make mistake in the calculation of the bottom-hole pressure. If the gas condensate outlet flow rate is not equal to the gas outlet flow rate, accumulation will occurs in the well. In wells with wellhead pressure higher than the pipeline pressure, fluid accumulation cause a little problem, but in wells with wellhead pressure close to pipeline pressure, fluid accumulation is a serious problem [1].

Determination of the minimum gas velocity to discharge fluid from gas wells, especially in old gas fields which are faced with pressure drop is a very important issue. In low pressure gas wells, accumulated fluids in pipes are the main reason of abandonment of premature wells and uneconomical production from them. Up to now, some researches has been done by Tooter (1969), Coleman (1991), Nasir (1997), Lee (2001) and Weeken (2003). Each of these studies has provided a different perspective to predict the gas flow rate and different models for different phase’s movement. These researches were conducted at wellhead pressure less than 1500 psi. In this study, by using of gas-liquid two-phase flow simulation in Eclipse E300 software and VFPi module, liquid accumulation in gas wells is investigated. For this purpose, affecting parameters on the liquid accumulation is imported to the software and consequently, according to the simulation results, the amount of liquid accumulation in variety of conditions is calculated.

Review of studies
Duggan [2]

Duggan have used the back pressure test data and by usage of the points that were not on the curve, reached to the following conclusion:

The minimum flow rate required to prevent the liquid accumulation is 5 ft/s.
The required flow rate to prevent of liquid accumulation in well is independent of the percentage of liquid produced from the well.

Turner et al*. [3]*

Turner et al. considered two types of movement for liquid and gas flow in the well: 1- The movement of liquid film on the tube wall and 2- The liquid drops movement by the core of gas flow.

Dukler and Hewitt model is used for liquid film's movement, and for liquid drops movement in the core of the gas flow, by establishment of the force balance for forces which governing the motion of drops and making an assumption that the drops are spherical, offered a prediction model for gas velocity. By using of equation (1), the minimum gas flow rate of the fluid for continuous discharge can be calculated.

$$V_t = 17.6\frac{\sigma^{1/4}(\rho_L-\rho_g)^{1/4}}{\rho_g^{1/2}} \qquad (1)$$

After comparing the model with the field data and taking into consideration of the affective factors on gas flow rate, the above equation was corrected and 20% of safety factor was added, finally, equation (2) was achieved.

$$V_t = 20.4\frac{\sigma^{1/4}(\rho_L-\rho_g)^{1/4}}{\rho_g^{1/2}} \qquad (2)$$

It was concluded from equation (2-2) that the ratio of liquid to gas production up to 130 barrels per a million cubic feet has no effect on the minimum flow rate and if water and condensates are produced simultaneously, denser phase (water) must be used in the calculations.***Ilobi and Ikoku*** *[4]*

Ilobi and Ikoku by use of Presented relations by Hougmark for calculating the gas flow rate, and Dans and Ras's relation for pressure gradient, had investigated the accumulation of fluid in gas wells. Fluid transmission with continuous gas phase flow is occurred in the annular and foggy flow regime. In this regime liquid strip moves up on wall by creating waves and gas flow containing liquid droplets moves in the center of tube more quickly. When the gas velocity is low liquid strip thickness increases gradually and finally moves downward, but when the gas velocity is high more waves appear in the liquid strip and finally liquid droplets go in to the gas flow and move upward. Coding of the presented model in this paper is so easy and can be used for variety of well geometries and thermodynamics. The most effective parameters that influence the liquid transfer with gas flow are: Tube diameter, Pressure, Gas density and Liquid residue. **Coleman et al.** [5]

Coleman et al. investigated liquid accumulation in wells with wellhead pressure of less than 500 psi. According to the Turner's theory, gas critical velocity depends on the particle size, particle shape, fluid density and viscosity. Equation (2-3) is provided to calculate the final speed where 20% of safety factor was also considered.

$$V_t = 1.912\frac{\sigma^{1/4}(\rho_L-\rho_g)^{1/4}}{\rho_g^{1/2}} \qquad (3)$$

With this equation, minimum required flow rate (critical flow rate) for continuous fluid discharge can be calculated.

$$q_c = 3.06\frac{p v_t A}{Tz} \qquad (4)$$

It is observed that the model can provide acceptable results for low pressure wells without safety factor. This model can be used for calculating final velocity of liquid droplets as follows.

$$v_t = 1.593\frac{\sigma^{1/4}(\rho_L-\rho_g)^{1/4}}{\rho_g^{1/2}} \qquad (5)$$

Nosseir et al. [6]

Nasir et al. studied the appropriate flow rate to prevent of liquid accumulation in variety of flow regimes and presented a model to calculate minimum required flow rate to prevent liquid accumulation in the well. Basic fundamental of this model is as Terner et al.'s model but in this model, variety of conditions and regimes were considered.
Two major forces effect on the falling droplet:
1. Gravity force which pull the droplets down.
2. Gas flow tension force which push the droplet upward.

$$F_g = \pi d_p^2/6 * (\rho_p - \rho) g_c \quad (6)$$

$$F_d = C_d \rho_p V_g^2/2 * \pi d_p^2/4 \quad (7)$$

In the above equations F_g is the gravity force, dp is the diameter of droplet, droplet density, gas density, g gravity acceleration, F_d gas flow tension, C_d tensile coefficient and V_g is the gas critical flow rate. In the proposed model, at first it calculate the tensile coefficient for each regime, then the tension force related with the coefficient is obtained, and finally minimum flow rate (critical) will be obtained. In this study, two models for transient and turbulent flow regime are offered. Equation (2-8) shows the gas flow rate in the transient flow regime and the Equation (2-9) shows the gas flow rate in turbulent flow.

$$V_g = 14.6\, \sigma^{0.35} (\rho_p - \rho)^{0.21}/\mu^{0.134} \rho^{0.426} \quad (8)$$

$$V_g = 21.3\, \sigma^{0.25} (\rho_p - \rho)^{0.25}/\rho^{0.5} \quad (9)$$

Lee et al. [7]

Lee et al. provided a model to obtain the minimum gas flow rate for continues fluid discharge. In this model the shape of liquid drops is assumed to be flat unlike the Turner and colleagues who assumed it as spherical shape. Effective surface of spherical shape is less than the flat drops, therefore, transfer of spherical droplets requires more flow rate. In this article, investigating the controlling forces of droplets movement provided relations to obtain the movement velocity and critical flow rate as follows.

$$V_t = 2.5 \sqrt[4]{\frac{(\rho_L - \rho_g)\sigma}{\rho_g^2}} \quad (10)$$

$$q_c = 2.5 \times 10^8 \frac{Apv_t}{zT} \quad (11)$$

Modeling:

To make the reservoir geometry, a cubic structure was made by Eclipse software E300. So production from the reservoir by eclipse software and production from the well by VFPi will be simulated simultaneously. At each step after calculation of bottom-hole pressure and flow conditions and thermodynamic conditions of the fluid in the wellhead by Eclipse software, VFPi module by use of these values, calculate the pressure and fluid phase behavior in the well column. To build the reservoir geometry, Mokhtari et al.'s [9] study is used. In the Mokhtari et al.'s study the effect of various parameters of reservoir on the productivity of the well, liquid accumulation in reservoir and phase behavior of condensate reservoir was investigated by reservoir simulation.

Mesh generation:

Mesh generating is performed based on the Mokhtari et al.'s study. In this simulation, a cubic structure with a well in center is modeled. Number of elements in X, Y and Z direction respectively is 11, 11 and 10. Also each element length in X, Y and Z direction respectively is 980, 980 and 405 feet. Production well is in the (6, 6) element in the direction of X and Y, and all elements have been completed in Z direction. Figure 1 show the model built in the software.

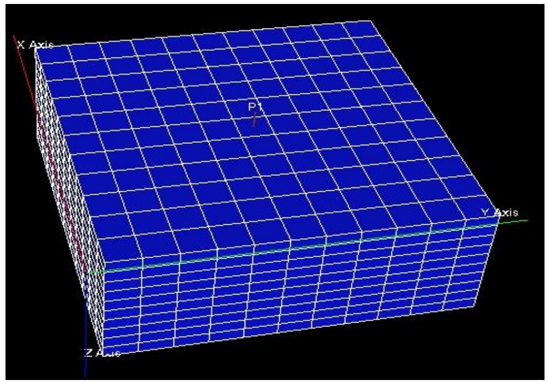

Figure 1. Structure of reservoir's mesh

Core and fluid properties of reservoir:

Porosity and permeability of simulated reservoir is extracted from Mokhtari et al.'s study [8]. Mokhtari et al.'s study was conducted on the Maroon reservoir and its properties also used for simulation. Reservoir petro physical properties and other characteristics are shown in Table 1-3. The study is on the gas condensate reservoir and its initial pressure at the base depth is 16026 feet which is equivalent to 12750 psi, initial contact surface between gas and water is 18629 and dew point pressure is 7588 psi. Reservoir aquifer type is Carter-Tracy and its petro physical properties are considered like other parts of the reservoir.

Table 1. Simulated reservoir properties.

Temperature (F)	Base pressure (psi)	Base Depth (feet)	Permeability (mD)	Porosity (%)	No. of elements in Z	No. of elements in Y	No. of elements in X
285	12750	16026	.32	5.9	10	11	11

Well's model

In well modeling, Shiferly et al.'s study is used. Shiferly et al. [9] investigate the liquid accumulation in a gas well by simultaneously simulation of well and reservoir. VFPi module in Eclipse software is used for well modeling. Initially well characteristics include tube diameter, well depth, composition of fluids in the well, reservoir temperature and wellhead temperature were imported to the software. Production well is completed from element (6, 6, 1) to (6, 6, 5) in the (X, Y, Z) directions. Intervals from 1 to 5 vertically include depth from 16026 to 18629 feet. Also other characteristics are imported to the VFPi module. Tube length is 18629 feet, tube hardness coefficient is 0.0006, tube diameter varies between 2 to 4 inches and upper pressure of tube varies between 300 to 500 psi.

The governing equations of the system as it mentioned before, three phases is considered in this simulation including: liquid hydrocarbon phase (oil), vapor (gas) and water phase. By mole balance establishment on the volume control for each "m" component the following equation is obtained.

For water:

$$\nabla.\left[\xi_o x_i \frac{kk_{ro}}{\mu_o}\nabla\Phi_o + \xi_g y_i \frac{kk_{rg}}{\mu_g}\nabla\Phi g\right] + q_i = \frac{\partial}{\partial t}\left[\phi(\xi_o s_o + \xi_g s_g) z_i\right], i = 1,...,n_c \quad (12)$$

$$\nabla.\left[\xi_w \frac{kk_{rw}}{\mu_w}\nabla\Phi_w\right] = \frac{\partial}{\partial t}(\phi\xi_w s_w) \quad (13)$$

In the above equations, "Φ", the potential of each phase is defined as follows:

$$\nabla\Phi_r = \nabla P_o - \gamma_r \nabla_h, r = o, g, w \quad (14)$$

$$\gamma_r = \rho_r g \quad (15)$$

Mole balance equation for whole the hydrocarbon system is obtained of summation of equation (1-3) on the "n_c" hydrocarbon components.

$$\nabla.\left[\xi_o\frac{kk_{ro}}{\mu_o}\nabla\Phi_o+\xi_g\frac{kk_{rg}}{\mu_g}\nabla\Phi g\right]+q_h=\frac{\partial}{\partial t}\left[\phi(\xi_o s_o+\xi_g s_g)\right] \tag{16}$$

Transformation of above equations in to the finite deference form will result in following relations:

$$\Delta\left[T_o^{\,n}x_i^{\,n}(\Delta P_o^{n+1}-\gamma_o^n\Delta h)+T_g^{\,n}y_i^{\,n}(\Delta P_o^{n+1}+\Delta P_{cog}^n-\gamma_g^n\Delta h)\right]+Q_i=$$
$$\frac{V_b}{\Delta t}\left[\phi^{n+1}(\xi_o s_o+\xi_g s_g)^{n+1}z_i^{\,n+1}-\phi^n(\xi_o s_o+\xi_g s_g)^n z_i^{\,n}\right],i=1,...,n_c \tag{17}$$

$$\Delta\left[T_w^{\,n}(\Delta P_o^{n+1}-\Delta P_{cow}^n-\gamma_w^n\Delta h)\right]+Q_w=\frac{V_b}{\Delta t}\left[\phi^{n+1}(\xi_w s_w)^{n+1}z_i^{\,n+1}-\phi^n(\xi_w s_w)^n\right] \tag{18}$$

$$\Delta\left[T_o^{\,n}(\Delta P_o^{n+1}-\gamma_o^n\Delta h)+T_g^{\,n}(\Delta P_o^{n+1}+\Delta P_{cog}^n-\gamma_g^n\Delta h)\right]+Q_h=$$
$$\frac{V_b}{\Delta t}\left[\phi^{n+1}(\xi_o s_o+\xi_g s_g)^{n+1}-\phi^n(\xi_o s_o+\xi_g s_g)^n\right] \tag{19}$$

$$Q_h=\sum_{i=1}^{n_c}Q_i \tag{20}$$

In the above equations, “T” is the transparency and is defined as follows:

$$T_r=\frac{kk_r}{\mu_r}\frac{A}{\Delta L} \tag{21}$$

In the above relations “ΔL” shows the length of block.
Phase equilibrium equations
Phase equilibrium equations are obtained of fugacity equality of each component in the gas and the oil phase.

$$f_{io}=f_{ig},i=1,...,n_c \tag{22}$$

After establishing a mass balance on the oil and gas phases, following algebraic relations are obtained:

$$z_i=Lx_i+Vy_i,i=1,...,n_c \tag{23}$$

$$V=\frac{\xi_g s_g}{\xi_g s_g+\xi_o s_o} \tag{24}$$

$$L=\frac{\xi_o s_o}{\xi_g s_g+\xi_o s_o} \tag{25}$$

Density and fugacity is calculated at the pressure of “P”. From the definition of molar composition and saturation, the following relation is also obtained:

$$\sum z_i=\sum x_i=\sum y_i=1.0 \tag{26}$$

$$L+V=1.0 \tag{27}$$

$$s_o+s_g+s_w=1.0 \tag{28}$$

The above equations are used for performing the calculations of equilibrium flash vaporization. As we know, before performing these calculations, systems stability must be controlled and several methods have been proposed by researchers for stability control. Michelson stability test which is based on the method of tangent plate’s length determination is used generally and this length is calculated for a mixture of “N_c” component as follows:

$$TPD(x)=\sum_{i=1}^{n_c}x_i(\mu_i(x)-\mu_i(z)) \tag{29}$$

μ_i shows the chemical potential. And in order to stability of the system, this parameter must always be positive.

Pressure equation:

To obtain the Pressure equation, the equation (7) is added to the equation (8):

$$\Delta\begin{bmatrix} T_w^{\ n}(\Delta P_o^{n+1}-\Delta P_{cow}^{n}-\gamma_w^n\Delta h)+T_o^{\ n}(\Delta P_o^{n+1}-\gamma_o^n\Delta h)+ \\ T_g^{\ n}(\Delta P_o^{n+1}+\Delta P_{cog}^{n}-\gamma_g^n\Delta h) \end{bmatrix}0+Q_w+Q_h$$

$$-\frac{V_b}{\Delta t}\left[\phi^{n+1}\alpha^{n+1}-\phi^n\alpha^n\right]=0 \tag{30}$$

Which “a” in above equation is determined as follows:

$$\alpha=\xi_g s_g+\xi_o s_o+\xi_w s_w \tag{31}$$

Amounts of “Q_h” and “Q_w” respectively indicate the volumetric flow rate of injection and hydrocarbon and water production.

Solving of Pressure’s equation

If we consider the left side of equation as “F_j” for j block, $P_{o,j}^{\ l}$ is as the l to repeat order of “P_o^{n+1}”, to obtain the $l+1$ to repeat order, the Newton’s repeat method is used as follows:

$$\sum_k J_{jk}^{\ l}\left[P_{o,k}^{l+1}-P_{o,k}^{l}\right]=-F_j^{\ l},\ j=1,\dots,n_b \tag{32}$$

In the above equation, “J” is the Jacobin matrix, which is approximated as follows and “K” is the numbers of the blocks which are neighbors with the block of “J”:

$$J_{jk}^{\ l}=\left(\frac{\partial F_j}{\partial P_{o,k}}\right)^{(l)}=(T_w+T_o+T_g)^n_{(\frac{j+k}{2})} \tag{33}$$

$$J_{jj}^{\ l}=\left(\frac{\partial F_j}{\partial P_{o,j}}\right)^{(l)}=-\sum(T_w+T_o+T_g)^n_{(\frac{j+k}{2})}$$

$$+\left(\frac{\partial Q_w}{\partial P_o}\right)_j+\left(\frac{\partial Q_h}{\partial P_o}\right)_j-\frac{V_b}{\Delta t}\left(\frac{\partial\phi_\alpha}{\partial P_o}\right)_j^l \tag{34}$$

Generally, two conditions are considered to obtain the expressions of $\left(\frac{\partial Q_w}{\partial P_o}\right)_j,\left(\frac{\partial Q_h}{\partial P_o}\right)_j$:

a) If the well production (or injection) is in constant flow rate

$$Q_w=\xi_w^n\tilde{Q}_w^n \tag{35}$$

$$Q_m=x_m^{\ n}\xi_o^n\tilde{Q}_o^n+y_m^{\ n}\xi_g^n\tilde{Q}_g^n \tag{36}$$

So we have:

$$\left(\frac{\partial Q_w}{\partial P_o^{\ n+1}}\right)=0 \tag{37}$$

$$\left(\frac{\partial Q_h}{\partial P_o^{\ n+1}}\right)=0 \tag{38}$$

b. If the bottom hole pressure of the production (or injection) well is constant $(P_{bh}=etc)$:

$$\tilde{Q}_j^n=I_{wj}(P_{bh}-P_{o,i}^{n+1}) \tag{39}$$

$$I_{wj}=\frac{2\pi khf\ \lambda}{\ln(c\,\frac{r_{eq}}{r_w})+s} \tag{40}$$

At this condition:

$$\left(\frac{\partial Q_w}{\partial P_o^{n+1}}\right) = -I_{ww}\,\xi_w \tag{41}$$

$$\left(\frac{\partial Q_h}{\partial P_o^{n+1}}\right) = -I_{wo}\,\xi_o - I_{wg}\,\xi_g \tag{42}$$

To calculate the $\left(\frac{\partial \phi_\alpha}{\partial P_o}\right)$ we act as follows:

$$\left(\frac{\partial \phi_\alpha}{\partial P_o}\right)_j^l = (s_w\,\frac{\partial \xi_w}{\partial P_o} + s_g\,\frac{\partial \xi_o}{\partial P_o} + s_g\,\frac{\partial \xi_g}{\partial P_o}) \tag{43}$$

After each repeat, after calculating the P_o^{n+1} from equation (6), the composition is obtained explicitly as follows:

$$z_i^{l+1} = \begin{Bmatrix} \Delta\left[T_o^n x_i^n \Delta\phi_o^{n+1} + T_g^n y_i^n \Delta\phi_g^{n+1}\right] + q_m + \\ \frac{V_b}{\Delta t}\phi^n (\xi_o s_o + \xi_g s_g)^n z_i^n \end{Bmatrix} \div \left[\frac{V_b}{\Delta t}\phi^{l+1}(\xi_o s_o + \xi_g s_g)^{l+1}\right] \tag{44}$$

Water saturation is calculated as follows, in each repeat from the water balance equation (eq. 7):

$$s_w^{l+1} = \frac{\Delta T_w^n \Delta\Phi_w^{l+1} + q_w^n + \frac{V_b}{\Delta t}\phi^n \rho_w^n s_w^n}{\frac{V_b}{\Delta t}\phi^{l+1}\rho_w^{l+1}} \tag{45}$$

In order to obtain oil and gas saturation, flash calculation on z_m^{l+1}, at each block's pressure and temperature is performed, so, amounts of $x_m^{l+1}, y_m^{l+1}, \xi_o^{l+1}, \xi_g^{l+1}, V^{l+1}, L^{l+1}$ are specified and other saturations calculate as follows:

$$s_o^{l+1} = \left[\frac{(1-s_w)L\,\xi_g}{L\,\xi_g + V\,\xi_o}\right]^{l+1} \tag{46}$$

$$s_g^{l+1} = 1 - s_o^{l+1} - s_w^{l+1} \tag{47}$$

Design of Experiments:

Design of experiments is a statistical method which invented by Fisher in 1920's decade to investigate the effect of variety of factors on the agricultural product [10]. In the different methods of statistical designing; the tests are done according to a predetermined plan that is accepted in the form of statistical analysis which are performed according to their own justify. Using basis of statistical design methods is the researcher's technical idea, and statistics is used as a device and not as the aim, to investigate the effect of parameters and Interactions. In other words, all effective parameters must be known. This requires a complete mastery of the theory and mechanism of the process. Disregard of changing in any effective parameter on the response of the system without logical justification, make the analysis baseless and unrealistic. In order to examine the influence of various parameters on the gas flow rate in the gas wells, different design methods can be used. For use of these methods it is necessary to determine different levels and ranges of reasonable changes in the parameters. To perform the simulation and sensitivity analysis on the effective process parameters, two parameters of wellhead pressure and tube diameter was considered as the variables. Range of these variables is determined using the references. Generally in the references, wellhead pressure amount is assumed to be 300 to 500 psi. In this study, five levels is intended in the range, to achieve the best value. Second parameter is the tube diameter which is also investigated in the previous studies and it is expected to increase the flow rate and fluid discharge with decreasing of it. The tube diameter is assumed to be two to four inches. Table 2 shows the range and level of parameters.

Table 2. studied parameters and levels considered

Factors	Unit	Level 1	Level 2	Level 3	Level 4	Level 5
Wellhead pressure	psi	300	350	400	450	500
Diameter of the inner tube	inch	2	2.5	3	3.5	4

Response Surface Method (RSM):

Response Surface Method is a set of mathematical and statistical methods which is used to Develop, advance and optimize the processes which are involved with a lot of effective parameters, and the aim is to optimize the response. Response Surface Method has a remarkable application in planning, development and formulating of results in a system. In addition to analyze the effect of independent variables, this method makes a mathematical model that explains the process [11]. Central composite design which has the most application among the designs of Response Surface Method is used in this research. In the central composite design, it is possible to use five levels of independent variables, while not many experiments are required. This not only reduces the number of experiment, but also increases the prediction accuracy. In the primary simulation, the average values of parameters are imported to the software, and Output data were considered as the average results. Using these results and expands them to higher and lower values; other output values were estimated and used to calculate the well performance. Therefore, wellhead pressure and tube diameter was considered to be respectively 400 psi and 3 inches. Table 3 shows the results of primary simulation. For this purpose, at first the tube characteristics as it is shown in the figure 2 was imported and then they obtained data from reservoir simulation was imported in to the Tabular Data and VFP Data.

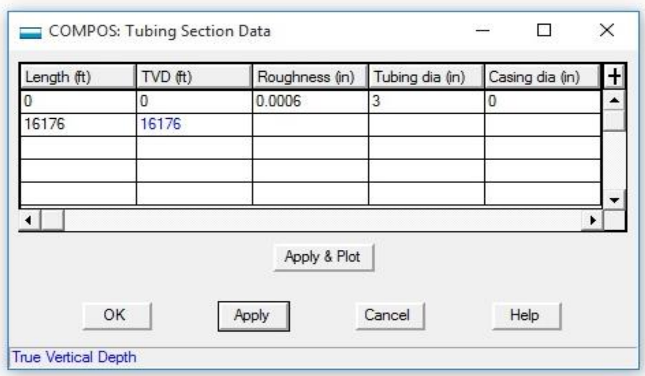

Figure 2. Central tube characteristics

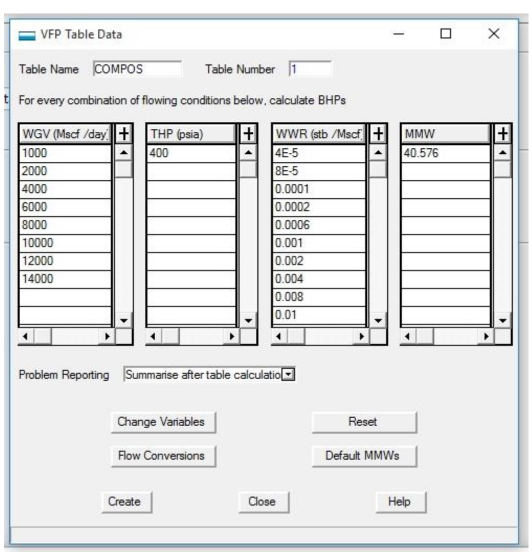

Figure 3: Fluid characteristics and wellhead pressure

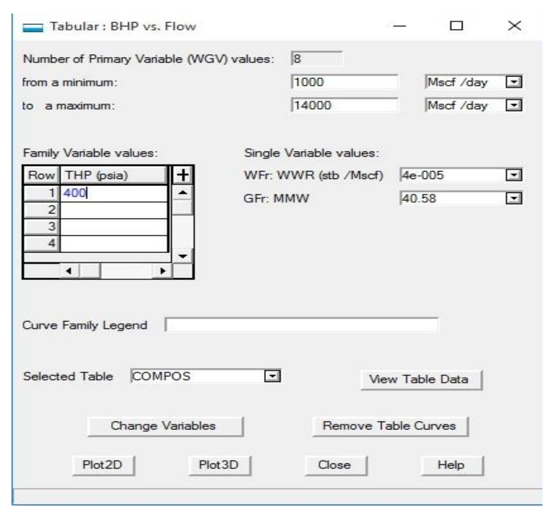

Figure 3: Fluid characteristics and wellhead pressure

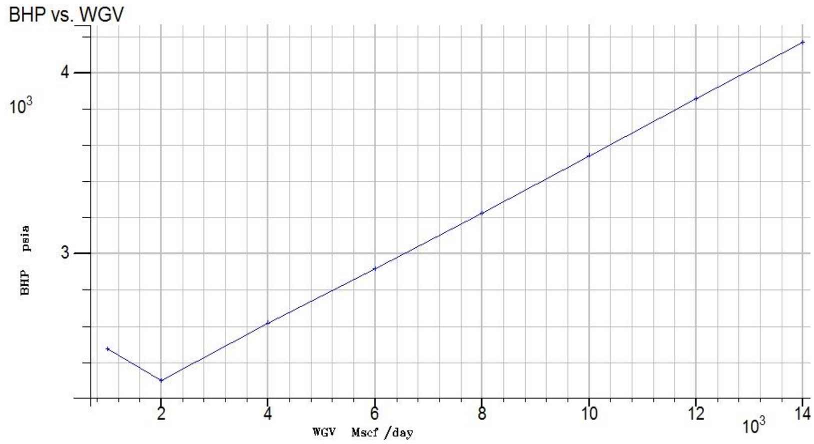

Figure 5. Bottom hole pressure changes in fluid production rate

Table 3. Primary simulation results

Oil recovery (%)	Gas oil ratio	Water oil ratio	Oil production rate (bbl/day)	Central tube (in.)	Wellhead pressure (psi)	Parameters
45	1	0.00001	10	3	400	Lower limit
45	50	0.06	5000	3	400	Upper limit

Using of Response Surface Method with two parameters and five levels, design performed and finally ten experiments is considered on the model.

Table 4. Designed runs

Central tube (inch)	Wellhead pressure (psi)	Experiment
3	500	1
3	400	2
2.5	350	3
4	400	4
2	400	5
3.5	450	6
3	400	7
2.5	450	8
3	300	9
3.5	350	10

All of ten predicted runs imported and executed in Eclipse. Above experiments have investigated after 18000 days from the beginning of production. In order to optimization and investigation of different parameters, it is necessary to consider an appropriate response for the analysis of the runs. Therefore oil recovery and accumulated oil and gas production, in each run was considered as the system response which the following table shows the result. The results shows that the most recovery and as a result the least oil accumulation in the well was occurred in the tenth run.

Table 5. results of runs which was designed according to simulation

Accumulated production (MSCF)	Oil accumulated production (STB)	Oil recovery(%)	Central tube (inch)	Wellhead pressure (psi)	Experiment
23209615	5441682	25.5	3	500	1
23878092	5463022	25.6	3	400	2
21837666	5399002	25.3	2.5	350	3
23268324	5441682	25.5	4	400	4
22471890	5420342	25.4	2	400	5
23240572	5441682	25.5	3.5	450	6
23878092	5463022	25.6	3	400	7
21074944	5356322	25.1	2.5	450	8
25141890	5505702	25.8	3	300	9
26055812	5548381	26	3.5	350	10

Tables 5 to 14 show the oil production rate in the different times and at different wellhead pressure and different central tube diameter. As it is observed at the following figures, oil production rate decreases at the high slope from beginning to 4000 days and after that converges to a constant rate. This decline in production and consequently the accumulation of liquids in the well is due to the pressure drop in the reservoir and well.

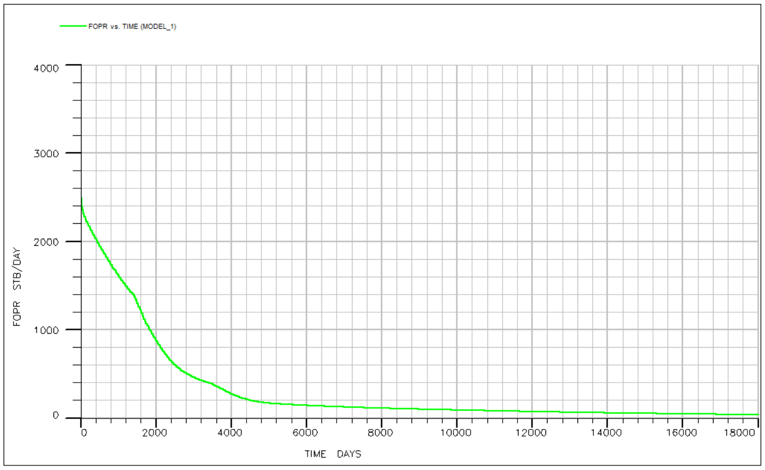

Figure 5. Oil production rate versus time (THP=300, TD = 3”)

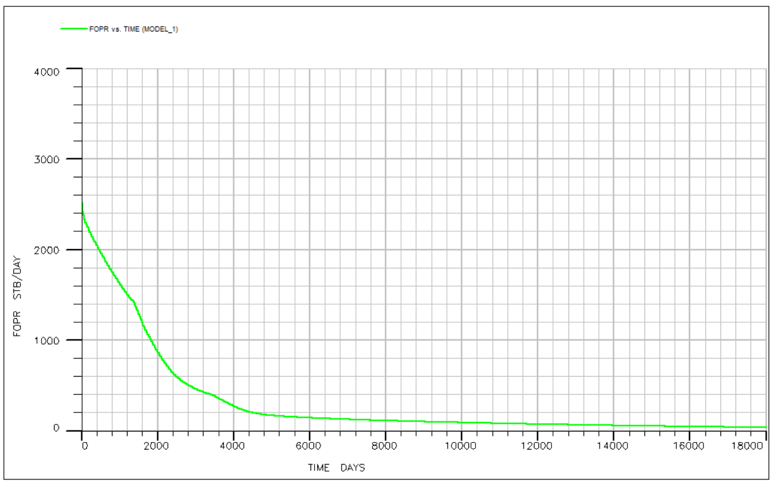

Figure 6. Oil production rate versus time (THP=350, TD = 2.5”)

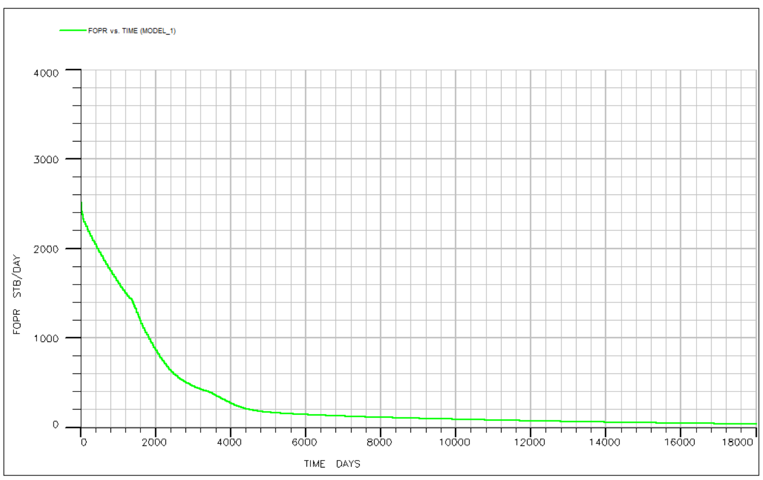

Figure 7. Oil production rate versus time (THP=350, TD = 3.5”)

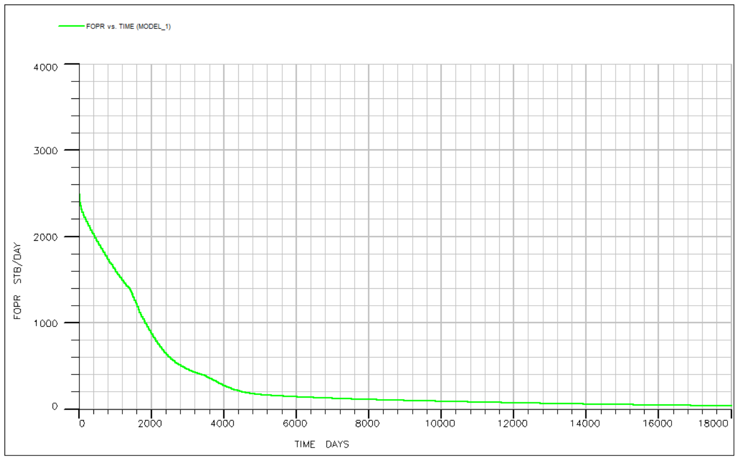

Figure 8. Oil production rate versus time (THP=400, TD = 2”)

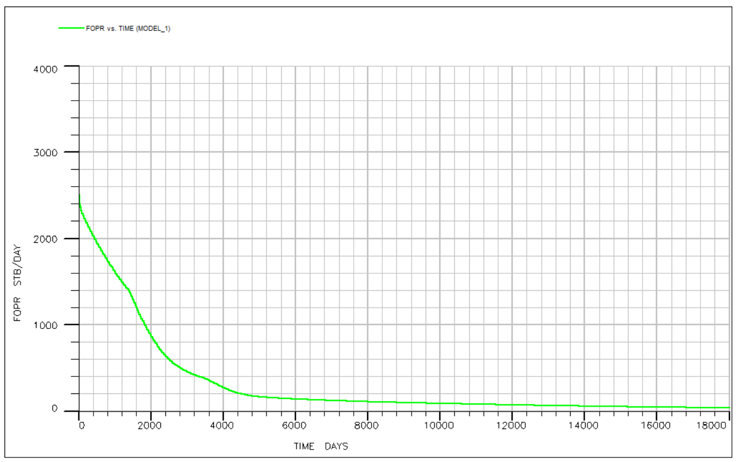

Figure 9. Oil production rate versus time (THP=400, TD = 3”)

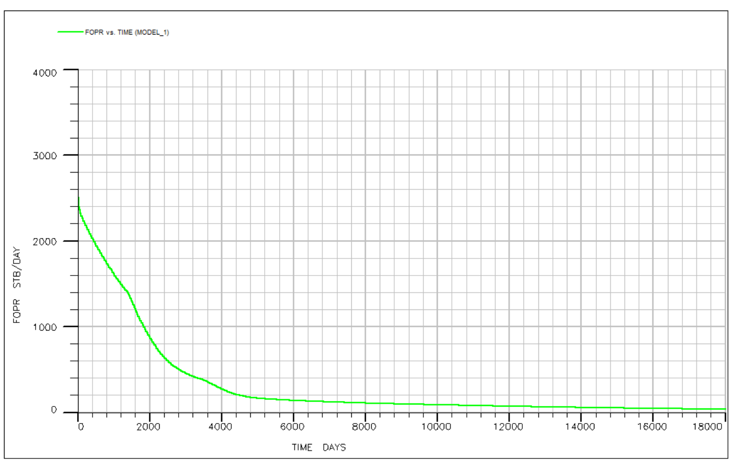

Figure 10. Oil production rate versus time (THP=400, TD = 3.5”)

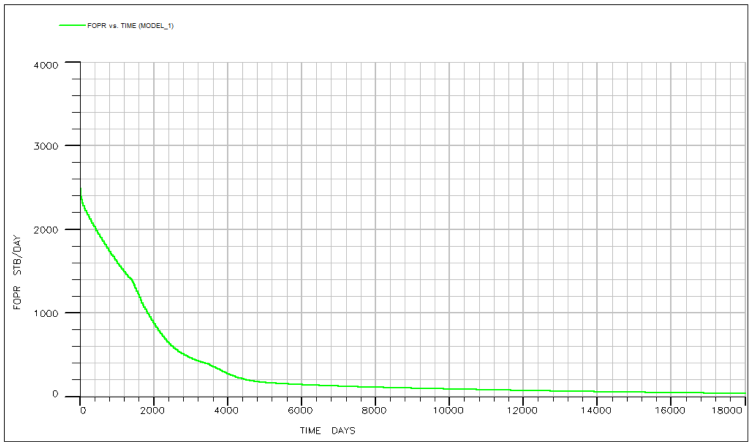

Figure 11. Oil production rate versus time (THP=400, TD = 4”)

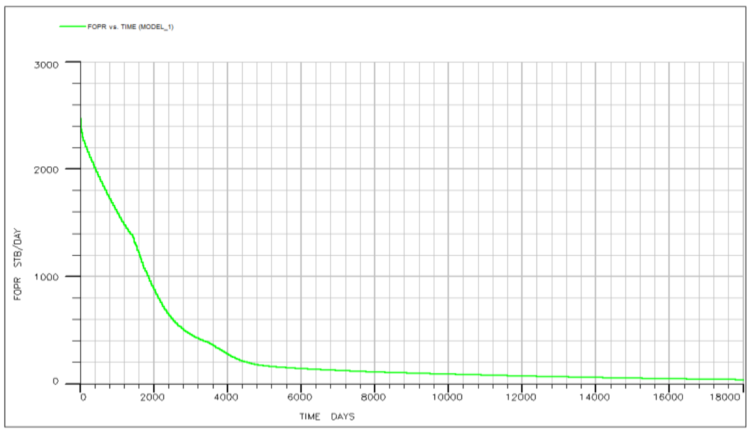

Figure 12: Oil production rate versus time (THP=450, TD = 2.5”)

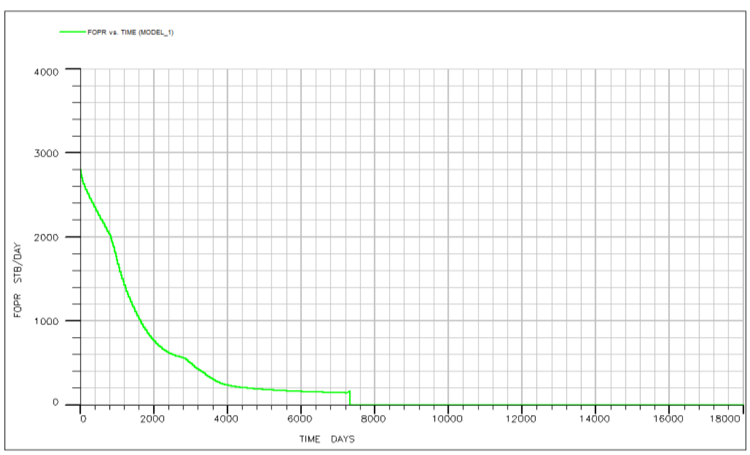

Figure 13. Oil production rate versus time (THP=450, TD = 3.5”)

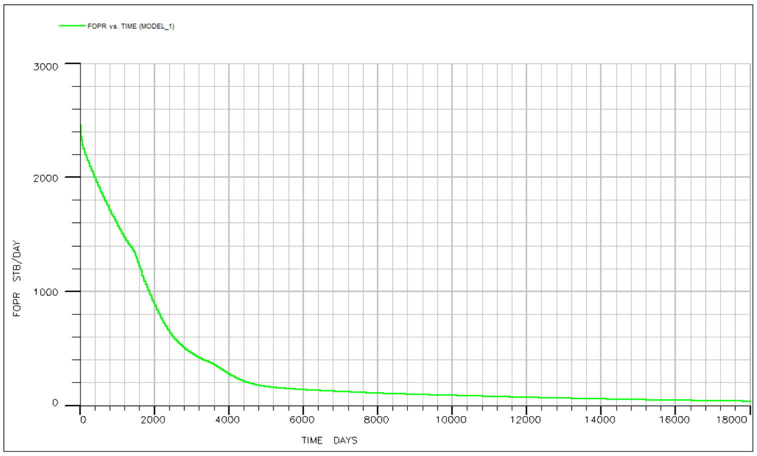

Figure 14. Oil production rate versus time (THP=500, TD = 3”)

The considerable point is the possibility of increase in the friction forces and more decrease in the well pressure due to the tube’s diameter decreasing. Simulation results show that the most production is occurred at the 3.5 inches of diameter. And in diameters less than 3 inches, recovery decreases. Figure 4-11 shows the recovery trend by changing in the tube diameter.

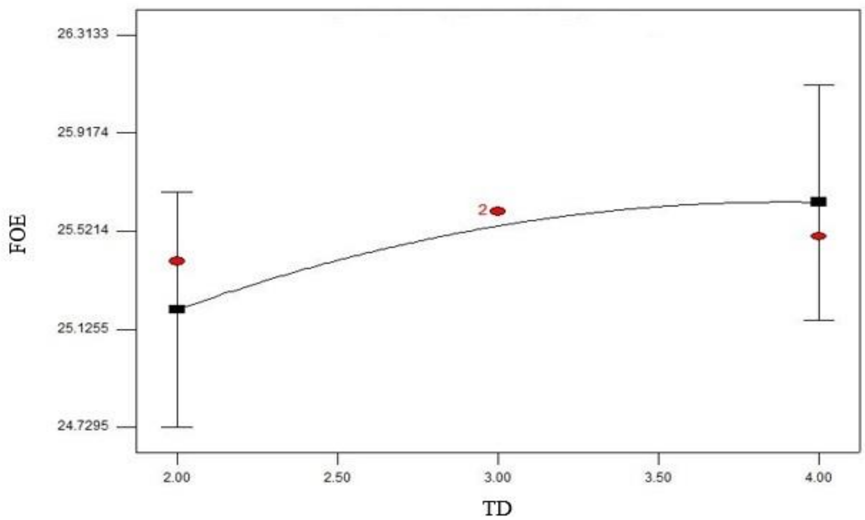

Figure 15. Oil recovery in different central tube diameters

The other important factor is the wellhead pressure. This parameter was studied in the simulation, and the result shows that the decrease in wellhead pressure leads to increase in oil recovery. In fact decrease in wellhead pressure leads to increase in the pressure difference and consequently increases the production from reservoir. The considerable point is that in the oil fields, wellhead pressure does not change in long ranges and usually in different areas, a single wellhead pressure is used for continues production from a reservoir. Therefore, in order to use of available relations and the results of the simulation, well conditions must be studied. Figure 16 shows the recovery trend in terms of wellhead pressure.

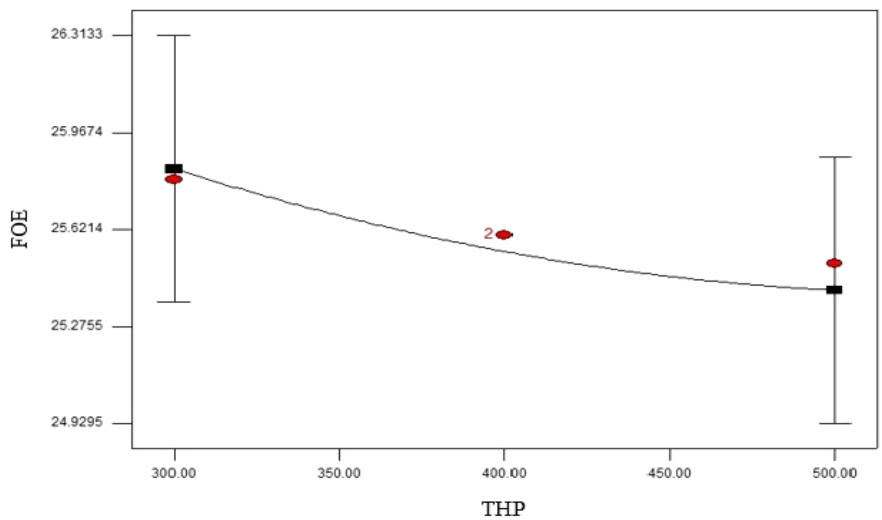

Figure 16. Recovery changes in terms of wellhead pressure

Also figure of oil recovery changes in terms of wellhead pressure and central tube diameter is showed below. As is evident in Figure 17, the most amount of oil recovery occurs at low pressures and high diameters.

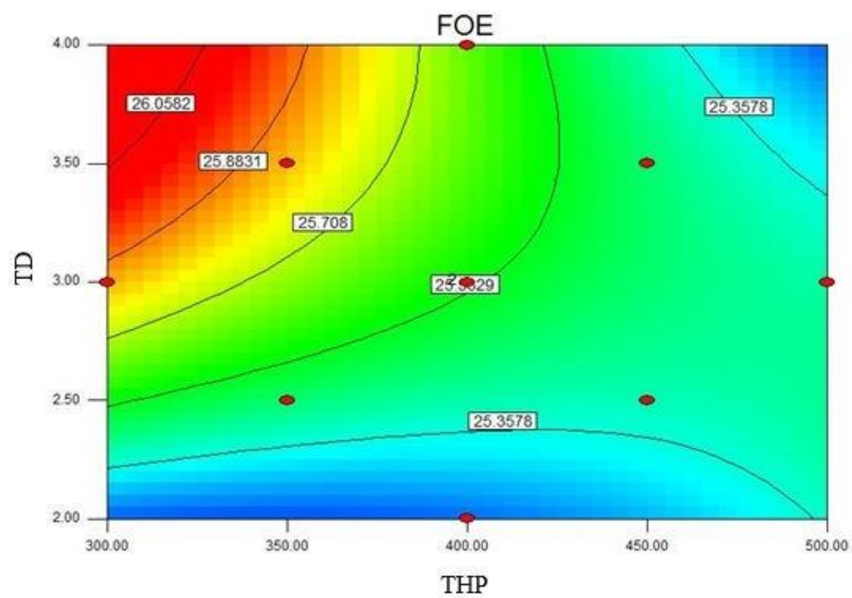

Figure 17. Effect of wellhead pressure and central tube diameter on the oil recovery

CONCLUSION

1) Oil recovery efficiency increases due to the decrease of the wellhead pressure.
2) Decrease in central tube diameter leads to increase in flow rate slightly,
3) Consequently leads to increase the liquid carrying capacity by gas.
4) At the diameters lower than 3 inches, production efficiency decreases.
5) According to the results, wellhead pressure of 350 psi and central tube diameter of 3.5 are the optimum values and the most efficiency occurs at these conditions.
6) Production rate decrease from beginning up to 5000 days and after that continues constantly.

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