

Optimization of Gas Allocation in an Iraqi Oilfield (East of Baghdad) in the Gas Lifts Process

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ABSTRACT

Gas lift operation is one of the most common artificial lift methods that may be applied to obtain maximum production rate with minimum flowing – bottom hole pressure. The goal of this project is achieved by injecting gas to the wellbore in order to move oil to the surface. We chose gas lift in three wells in East of Baghdad field. In this study, a program has been developed using basic programming language to calculate the flowing – bottom hole pressure by using two correlations which are : modified Beggs – Brill and Aziz. The results showed that the gas injection rate for wells No.(10,11) are (15 MMSCF/DAY) to give maximum production rate of (3430 STB/DAY) , (2970 STB/DAY) with minimum flowing – bottom hole pressure (4287 psi) , (4105 psi) , respectively. Also the maximum injection rate for the well No.(19) is of (7 MMSCF/DAY) with flow rate (3512 STB/DAY) and flowing – bottom hole pressure (4187 psi). current production rate for wells (10,11,19) are (2450,2100,3100) STB/DAY respectively.

Keywords : Optimization, Gas Lift, Artificial Lift, Maximum Available Lift-Gas

I. INTRODUCTION

Usually by continuing oil production, reservoir pressure de-creases and causes the oil rate to fall below the economical rate. In this situation, different artificial lift methods such as gas lift are used. In the gas lift, gas is injected to a well via the annulus. It is dissolved in oil and thus decreases the density of the oil column. This causes the reservoir pressure to be enough to produce the oil (Jahan shahi et al., 2008). Now if the lift gas injection rate is less than a threshold, it cannot produce a continuous oil flow. In fact, it ac- cumulates in the annulus to increase its pressure, and after its pressure increased it suddenly flows to the tubing and causes the oil flow. This causes the pressure reduction of the annulus and thus gas cannot move to the tubing until its pressure increases and also oil production stops. In addition to the reduction of the oil pro-duction, this periodical shutdown causes huge vibrations which damage down hole facilities. Different aspects of this problem have been studied in different literature. For the first time in 1945, Gilbert (Gilbert, 1954) studied. instability, and suggested using some kinds of packer to eliminate its vibrations. After him in 1953, Bertuzzi

(Bertuzzi et al., 1953), introduced an equation to predict instability. Also in 1988, Blick (Blick et al., November 19 88) pre-dicted the unstable flow using the Laplace transformation. In 2004, Fairuzov (Fairuzov et al., 2004) plotted some maps to show the stable and unstable regions; in addition to that he considered some operating limits in his maps. In 2005, Poblano (Poblano et al., 2005) drew some maps to show the stable and unstable regions. In 2008, Eikrem (Eikrem et al., 2008) introduced a dynamic model and using that plotted some stability maps. In 2011, Aguiar (Aguilar and Poblano, 2011) studied the stability in the wells that are imposed to water conning. As well as in this year, Maijoni (Maijoni and Hamouda, 2011) studied the effect of the injection gas composi-tion on gas lift stability. In 2013, Guerrero-Sarabia (Guerrero-Sarabia and Fairuzov, 2013) analyzed the instability by linear and nonlinear methods. He investigated the effect of the heading severity on the amount of production loss.

II. METHODS AND MATERIAL

Problem Modeling

The question that is answered in this part is what we want to measure, what we need and how it will be done. We need to see whether considering stability as a constraint in gas allocation optimization will be an efficient way to escape the problems of instability or not. Here, in some case studies this claim will be tested. In the case studies, some wells are needed. Then a fixed amount of lift gas is allocated between them. This allocation is optimized by the genetic algorithm and the amount of oil production (in considering or ignoring stability) is measured and compared. (Fig. 1) shows a schematic of the works carried out in this paper. As mentioned earlier, first of all, some wells are needed to test the new approach on them. For this purpose, some wells of the Iraqi oilfields (different number of wells for different scenarios) are considered. All of these wells were drilled in East of Baghdad sandstone formations. These wells were produced by natural forces at the beginning of the well completion. But by continuing the oil production, the reservoir pressure declined and thus the oil production rate fell below the economical rate. As the wells are near each other and have sand production (because of sandy formation), the best artificial lift method for them is gas lift. For this means, a central compressor is used and the total compressed gas is constant, but it can be divided with different fractions among the wells. The injected gas is gained from the same field. Thus, in this study, the produced gas and injected gas are highly similar. The wells of this study are completed with a packer, and continuous gas lift is applied in which gas is injected through annulus and oil is produced through tubing and tubing and annulus are separated by a packer. Gas is injected through only one point in the well and the range of injection depth of different wells is shown in Table 1. The optimization problem consists of determining the specific amounts of gas for each well such that the total oil production reaches a maximum and the total injection gas should not exceed a limit. Now the wells are introduced, and their properties in addition to the properties of the formation and reservoir are illustrated. Now the lift gas can be allocated among them. But a mathematical model is required to predict the amount of total production, and later on the production of considering and ignoring stability will be compared. We call this model the fitness function. Fitness function is a function which takes the variables that can be changed through the problem as input, and calculates the parameter that we want to

maximize or minimize using these variables. In this study, this function should take the gas injection rates of the wells as input and calculate the total oil production rate as output. The properties of the reservoir and wells are about the range of the Iranian oilfields which can be seen in Table 1. In the fitness function, first the oil rate production of each well should be calculated. To calculate the oil rate of a well, nodal analysis is used. Usually nodal analysis is used for natural flow and analysis is similar to that. At the beginning there is a need for some empirical correlations for fluid and flow properties estimation. Here, for fluid properties, modeling the most accurate models based on different literature (Brill and Beggs, 1991a) (Takacs, 1989) (Khomehchi, et al., 2009) have been used. For example, for critical pressure and temperature Standing (Vatani and Mokhtab, 2004a), for gas compressibility factor Standing and Katz (Standing and Katz, 1942) and Papay (Papay, 1968) and for viscosity of gas and oil Lee (Takacs, 2005) and Beal (Beal, 1946) have been used respectively and solution gas oil ratio has been modeled by Laster (Lasater, 1958a) equation. These equations are listed in Table 2. This table shows the correlations for the fluid properties as well as a two phase flow equation and a temperature estimation method. The Ansari (Ansari et al., 1994) correlation is used for the two phase flow and the Hasan-Kabir (Hasan and Kabir, Aug 1994) correlation is used for temperature estimation. This equation has very good estimation and considers different parameters such as slippage and flow regime for the flow equation and the joule Thomson effect and heat balance in the temperature estimation equation. For more information regarding these methods, refer to the references provided. In this calculation, different correlations were used. These are the most accurate ones based on different literature (Brill and Beggs, 1991b), (Takacs, 1989), (Pourafshary, 1979), (Bendakhlia and Aziz, 1989), (Renanto and Economides, 1998), (Patton et al., September 19 80). In order to apply the effect of gas lift, the gas lift effect is added by considering a different gas liquid ratio (GLR) in the above injection point. It was previously mentioned that the injected gas is recovered from the solution gas of the same reservoir, and thus its composition is similar to the produced gas and can be considered just as a higher GLR above the injection point. As well as the effect of well in production, there is a need to involve the effect of reservoir, and cross plot the results to find the oil rate of

wells. The effect of reservoir is summarized in the IPR concept. The IPR model used in this study is the Vogel (Vogel, Janury, 1968) equation (IPR). Most of the gas lift wells are unsaturated, and hence the Vogel method is selected based on different references. Vogel is one of the most suitable algorithms for these kinds of reservoirs (Golan and Whitson, 1995). Its equation is shown in equation (1).

$$VSg=0.25VS + 0.333VS1$$

Where VS is the slip or bubble – rise velocity given by :

$$VS=1.53 \left(\frac{g\sigma 1 (\rho 1 - \rho g)}{\rho 1 2} \right)^{1/4}$$

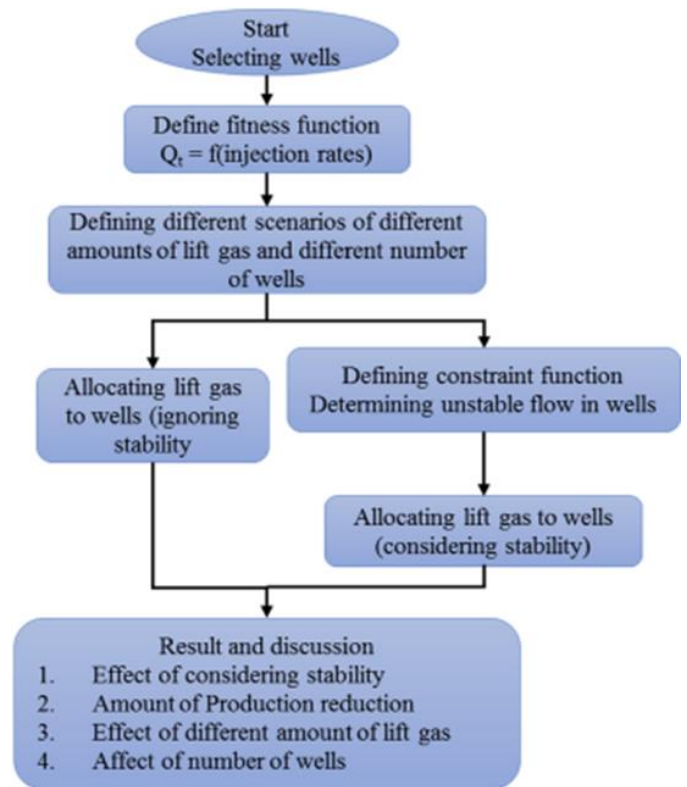


Figure 1. Schematic of this paper's procedure

Table (1) Well and Reservoir Data

	Well 1	Well 2	Well 3	Well 4	Well 5
Well Depth, m	3160	3200	3130	3070	3150
Reservoir Pressure, Psi	5260	5400	5020	5100	4970
Reservoir Temperature, c	101.7	102.3	101	101.7	102.1
Bubble Point Pressure, Psi	1184	1180	1210	1160	1193
Water Cut, %	0	0	0	0	0
Tubing Size, inch	3.5	31.2	3.5	31.2	31.2
Casing Size, inch	95.8	95.8	95.8	95.8	95.5
Oil Gravity, API	26.25	26.6	25.5	26.4	26.1
Well Head Pressure, Psi	317	317	317	317	317
Well Head Temperature, c	75	75	75	75	75
Bottom Head Pressure, Psi	4700	4750	4640	4790	4750
Surface Injection Gas Pressure, Psi	1500	1500	1500	1500	1500
Well Completion	Vertical	Vertical	Vertical	Vertical	Vertical

It is assumed that the injection depth and the tubing size for each well during the gas lift operation is fixed and the only variable is the share of lift gas for each well. The result was the calculation of the production rate of a well with a determined lift gas injection rate. Now this procedure for other wells with their known gas injection rate is repeated and the oil rate production of each one is calculated. The production rates of all the wells are added and the Q_t (the sum of production rates as the output of the ness function) is calculated. In summary, here the fitness function input is the injection rate of all wells and its output is the sum of the production rates of those wells .Until now, the wells were introduced and a model for predicting the total oil production for a specific gas allocation was created. In the case of ignoring stability, using an optimizer algorithm like the genetic algorithm, the optimum gas allocation can be easily found .But if stability is needed to be involved, another model for fore-casting it is necessary. To consider the constraint (instability) for the optimizer, the Asheim equation is used. Its relation is shown in equations (1)e(3).

$$F_1 = \rho_{gsc} B_g q_{gsc}^2 / q_{Lsc} \times J / (EA_i) \quad (2)$$

$$F_2 = CV_t / V_C \times 1 / g D_i \times p_{ti} / (\rho_{fi} - \rho_{gi}) \times (q_{fi} + q_{gi}) / q_{fi} (1 - F_1) \quad (3)$$

$$C \sim 1 \quad (4)$$

Asheim introduced two factors F 1 and F 2 to distinguish the stable and unstable regions, and he said that the flow is stable if one of F 1 or F 2 be higher than 1.

It is clear that in the Asheim equations for each well, all parameters except the injection rate (q_{gsc} or lift gas rate at injection point q_{gi}) are constant. Thus, in this study, stability is just a function of the gas injection rate. It should be mentioned that all the units used in the paper (except those used in F 1 and F 2) are field units, but to save the original forms of Asheim equations, the units of parameters used for calculating F 1 and F 2 are not fields, since before testing the stability of the flow the units of parameters are changed to Asheim and then F 1 and F 2 are calculated. In this part, the wells are initially introduced, and then a mode for predicting the total oil production of a specific injection is created. Finally, another model for forecasting the instability is made. In the next section, these models will be optimized and the effect of considering stability will be discussed.

Table (2) Gas Injection Rate and Oil Production Rate for a Set of 5 Wells (Initial Pr and W.C = 0%)

	Natural flow		Unlimited Available Gas		Equal Injection Rate		Production Weight Injection Rate		G. A.	
	qg (MMS CF/D)	q _o (STB/D)	qg (MMSCF/ D)	q _o (STB/D)	qg (MMSCF /D)	q _o (STB/D)	qg (MMSCF /D)	q _o (STB/D)	qg (MMS CF/D)	q _o (STB/D)
WELL 1	0	q _o (STB/D)	5	4015	1.6	3565	1.67	3605	2.1	3765
WELL 2	0	2600	4.5	4050	1.6	3425	1.57	3405	2.2	3775
WELL 3	0	2450	3	3435	1.6	3105	1.73	3130	0.9	2930
WELL 4	0	2700	5	3895	1.6	2985	1.48	2970	2.6	3545
WELLS	0	2300	6	3215	1.6	2650	1.55	2645	0.2	2450
Total		12460	23.5	18610	8	15730	8	15755	8	16465

3. Preventing instability by considering it as a constraint in gas allocation optimization:

In this section, the effect of considering stability as a constraint in different cases of gas allocation optimization will be discussed. Thus, between the six assumed wells, the assumed available lift-gas has been allocated in an optimum way. It is clear that when we have a fixed amount of lift gas and we want to allocate it between different wells, there are myriad ways for this allocation. Two kinds of optimum allocation can be defined, one in which the net profit maximizes and the second in which the total produced oil maximizes (Alarcón et al., 2002). In this study, as

the wells properties cannot be changed and the compressor is fixed and is working with constant power; the net profit corresponds to total oil production. Hence, the problem of this study is to allocate a fixed amount of lift gas between some previously defined wells in a way that the total oil production be maximized and have a stable flow.

The Genetic algorithm (GA) has been used as an optimizer and its parameters can be seen in Table 3. The Genetic algorithm is a heuristic optimization algorithm and works well in complex problems (in which many parameters change simultaneously).

Therefore, it has been selected to be used here. The chromosome or individuals of the optimizer are combinations of the gas injection rates of different wells. These individuals are initially created on a random basis. Then, in every iteration, all the individuals are evaluated and if some of them violate the constraint, they are penalized. Afterwards the best four individuals (with higher accumulated rates) go directly to the next generation (elite count) as well as for the next generations, some other individuals are generated by cross over and mutation. Then, it is checked whether the tolerance in the last 100 generations (if available) is less than $1e-6$ or not. If it is, the stopping criteria is met and algorithm finishes. After some generations (which are shown for each case in its convergence figure) the optimum point is found.

To add the stability constraint to the problem, first of all for each well the value of F1 and F2 for different

amounts of available lift gas (starting from zero and gradually increasing it) have been calculated and so the minimum value of lift gas to have the stable flow has been found. These values are listed in Table 4. The last row of Table 4 shows that the sum of all Q_g is equal to 3.411, and it is clear that the amount of lift gas should be at least this amount to make the stable flow possible otherwise at least one well would produce in unstable region. Based on the amount of maximum available gas, the problem can be categorized in three categories; less than 3.411

MMSCF/day, equal to 3.411 MMSCF/day and more than that. In each case, the gas allocation optimization has been run two times. At first, the stability has been considered and in the second case it has been ignored. Finally, the results have been compared.

Table (3) Physical Properties Correlations

Properties	Correlation
Solution gas oil ratio	Glaso
Oil formation volume factor	Glaso
Oil viscosity	Beal et al.
Gas viscosity	Lee et al.
Gas compressibility factor	Katz et al.

Table (4) Minimum amount of injection gas for stable flow for each well

Well no	Q_g (MMSCF/day)
Well 1	0.848
Well 2	0.593
Well 3	0.398
Well 4	0.402
Well 5	0.527
Sum of all injection rates	3.411

III. RESULTS AND DISCUSSION

For studying the effect of considering stability on the optimum point, different amounts of available lift gas have been assumed and their optimum points by considering and ignoring stability have been calculated and compared. In this problem we may consider the minimum amount of needed lift gas that make all wells produce in stable flow as 3.411 MMSCF/day. Thus there are three different conditions for maximum available lift gas. Having less than 3.411 MMSCF/day, equal to that and more than that.

4.1. Available lift gas less than 2 MMSCF/day

In the beginning, 2 MMSCF/DAY gas were assumed and allocated between the six previously mentioned wells, in a way that maximized the production. Fig. 2(a) shows the convergence of the algorithm. With this amount of available gas, stable allocation is not possible, so there is just one curve. The convergence of this curve starts from 25350 STB/day production to little more than 28500 STB/day, and it should be noted that the start point of the graph (point 28350) does not mean that at this point no gas lift operation is run; In this point only the gas allocation between the wells is different from the point 28500. And this graph shows the effect of optimization algorithm, not the effect of the gas lift. The amount of injected gas in all points is similar. This explanation is applicable for the convergence graph of other cases. Fig. 2(b) shows the lift gas share of each well and compares its value with the minimum required gas for the stable flow. As this figure shows, just in well 4 the amount of allocated gas is more than the minimum required gas for stable flow but in the other 5 wells its less and thus they are flowing in unstable region.

4.2. Available lift gas equal to 3.411 MMSCF/day lift gas

The next step is 3.411 MMSCF/DAY available lift gas, this value is the sum of all minimum required lift gas for the stable flow of each well. Fig. 3 shows the convergence of the optimum point in the case of ignoring stability. It is similar to the previous cases if stability be considered, there is just one point that the algorithm should find, thus it is impossible or very hard for the algorithm to find. so the algorithm for optimizing

this case (considering stability) has not found any acceptable solution. In Fig. 3 only the convergence of ignoring stability is shown. Fig. 3(b) shows the optimum points, and in the case of ignoring stability 2 wells are unstable.

4.3. Available lift gas of more than 3.411 MMSCF/day

The next step supposes a lift gas of 4 MMSCF/DAY. In this value, both optimization of considering and ignoring stability is possible. Fig. 4(a) shows the convergence of this two optimizations. As can be seen in this figure, in ignoring stability, the algorithm has searched a wider space and of course its optimum point has a higher production. Fig. 4(b) shows the optimum points of both optimizations. This figure shows that if the stability in an optimization algorithm is ignored, the difference of available lift gas with the required lift gas for stable flow is small and most wells will be in an unstable region. But if the amount of available gas increases, the situation is different. This is clear because considering stability adds a lower limit for injection rate. Fig. 5 shows the convergence of considering and ignoring optimization for the amount of 4.5 MMSCF/day available gas, and it can be seen in this figure that the convergence and optimum production of both cases are very close (despite Fig. 4). Fig. 5(b) shows the optimum points of both optimizations. As this figure shows, in ignoring stability, just 2 wells (well 2 and well 3) are in the unstable region. The next step is to suppose 6 MMSCF/day for available gas. Fig. 6 shows the convergence of the optimum gas allocation by ignoring stability, and it can be seen that it has searched a wide space to reach the optimum point and even ignoring the stability has led to a stable optimum point. The optimum point is shown in Fig. 6(b), and this figure shows that all wells are in stable region. It seems that a further increase in the value of the available lift gas will cause the optimum point to fall in stable region (even if stability is ignored in optimization). To make sure, another point with 8 MMSCF/day available lift gas has been supposed and its optimum point has been calculated. Fig. 7(a) shows the convergence of the optimizer and Fig. 7(b) shows the optimum point's value. It can be seen that increasing the available gas has made the optimum point farther than stable bound.

4.4. The effect of different amounts of lift gas on stable optimization

Fig. 8 shows the difference of the total oil production between considering and ignoring stability in optimization for different amounts of available lift gas, this figure shows that if the amount of available lift gas be less than a specific value (in this study 3.411 MMSCF/day) there is no stable flow. Having maximum available lift gas between 3.411 and 5 MMSCF/day (in this study) causes the optimum points of considering and ignoring stability to be different and having more than 5 MMSCF/day lift gas makes both optimum points of considering and ignoring stabilities coincide. Thus it should be considered that if the amount of available lift gas is near double (actually 1.6), the minimum amount of required gas for stable flow, considering and ignoring stability, will lead to different solutions. It should be mentioned that in all of the above cases, considering and ignoring stability, the optimizer needs a similar number of iterations to find the optimum point. In the above figures, the effect of considering and ignoring stability when we have a different amount of available lift gas is illustrated. Using them, the convergence of the optimization algorithm in these cases can be compared. The effect of considering stability on optimum allocation can be seen and the influence of the amount of available lift gas on the stable and unstable optimum points can be observed. It is clear that the value of the injected gas should be more than a specific value to have a stable flow, but the question is that whether increasing the amount of lift gas to more than a specific value, in all cases would lead the optimum point of ignoring the stability to the stable region or not? to answer this question, some wells with the properties of the range of Table 1 are assumed. Then by the worst assumption, with an unlimited amount of lift gas, an attempt is made to find a well in which the amount of required gas for its optimum point be less than the minimum required gas for stable flow. In this part, the meaning of the optimum point is a point that the injected gas maximizes its oil production and increasing or decreasing the amount of lift gas decreases its production oil rate. If such a well exists in any group of wells, its optimum gas share would be less or equal to its unlimited optimum point and would have an unstable flow. Fig. 9 shows the optimum and required amount of lift gas for different wells. It shows that after 2211 tests such a well is found.

Its optimum rate of injection gas rate for unlimited available gas was 0.18 MMSCF/DAY but less than 0.42 MMSCF/DAY causes an unstable flow. Also before that point, in 7 cases the value of optimum point and stable bound were very close (as can be seen in Fig. 9). So although in most cases by increasing the value of lift gas to more than a specific value, the probability of the optimum point (ignoring stability) to fall in an unstable region decreases, but as shown it is definitely not zero..

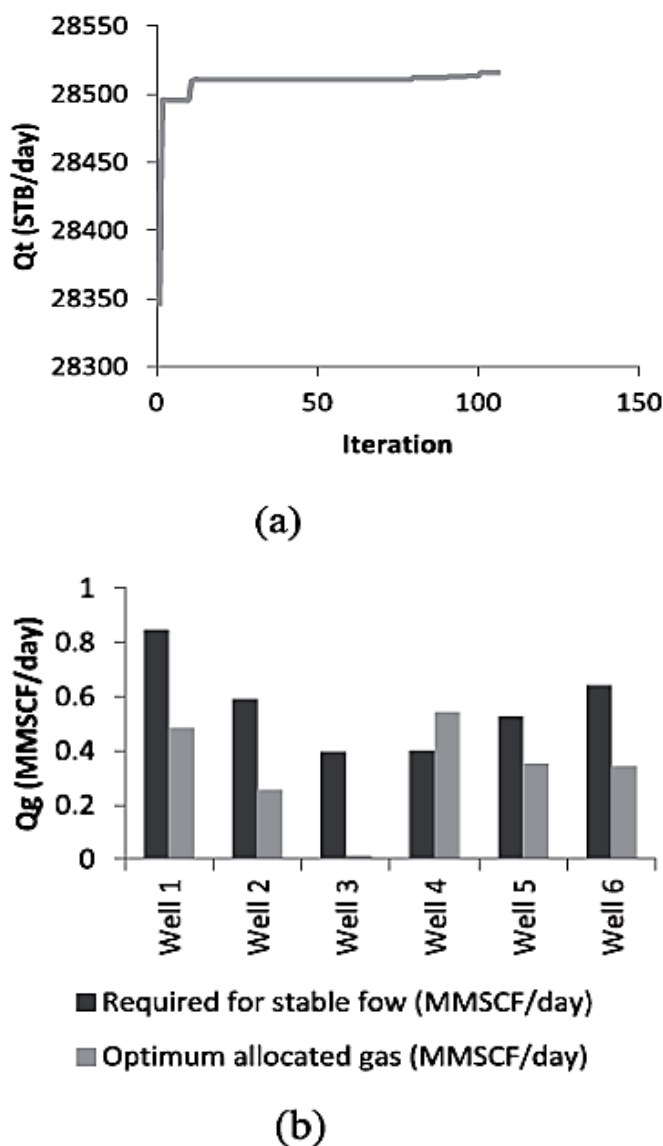
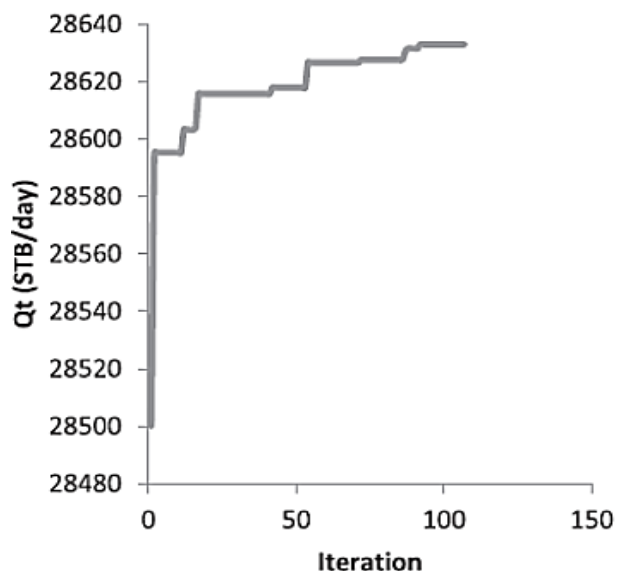
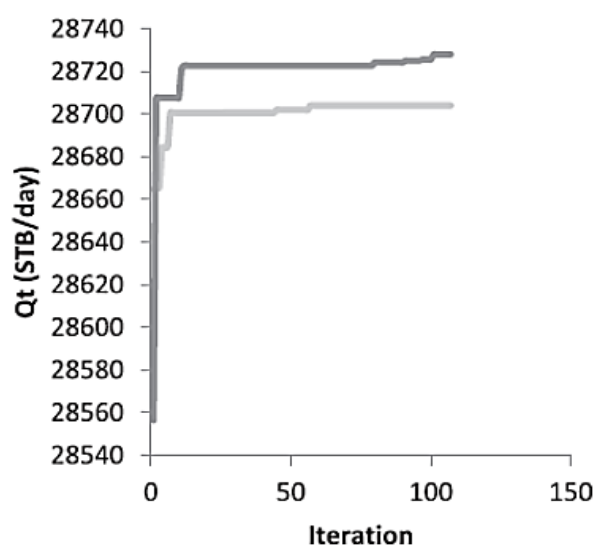


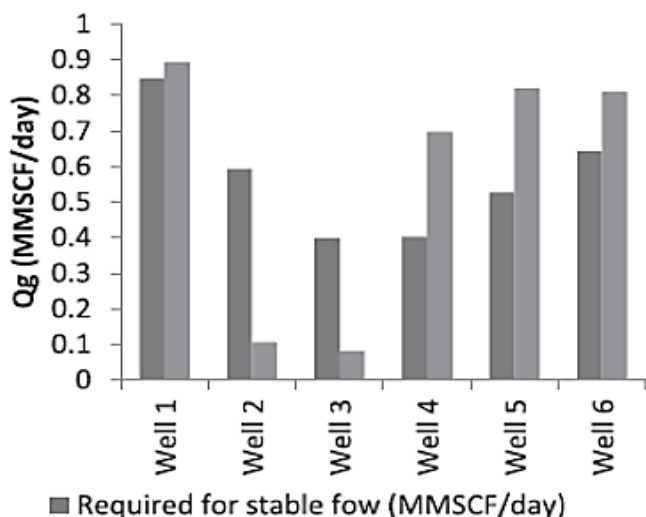
Figure 2. Gas allocation optimization of 2 MMSCF/day maximum available lift gas (a) convergence to optimum points (b) gas allocated optimum point



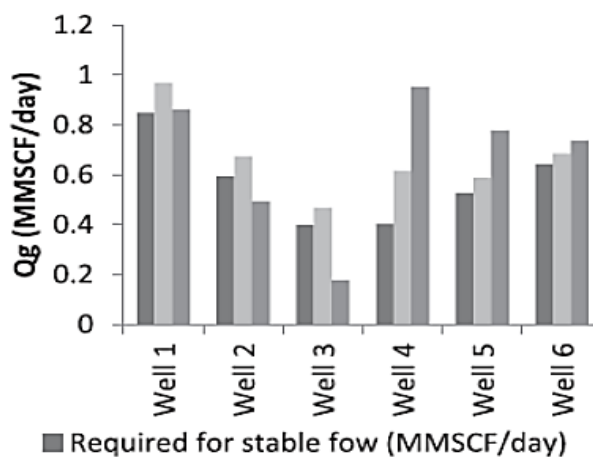
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(a)



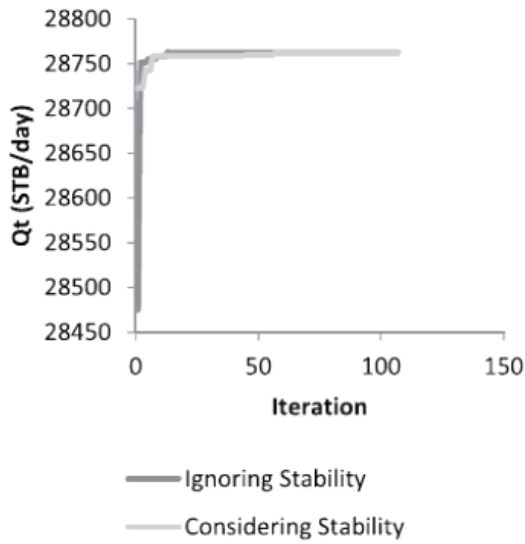
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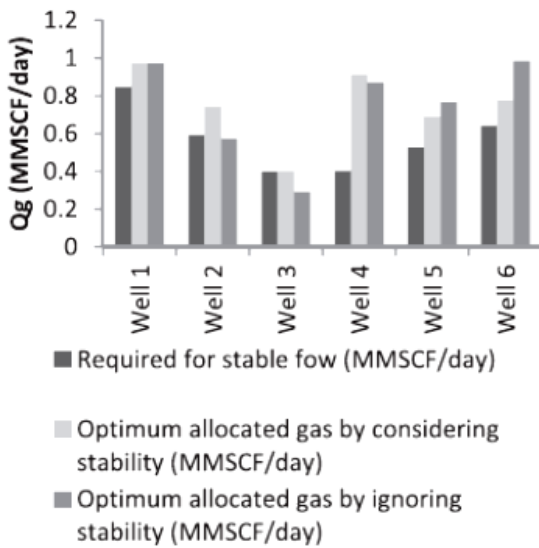
(b)

Figure 3. Gas allocation optimization of 3.411 MMSCF/day available lift gas (a) convergence to optimum points (b) gas allocated optimum point.

Figure 4. Gas allocation optimization of 4 MMSCF/day maximum available lift gas (a) convergence to optimum points (b) gas allocated optimum point

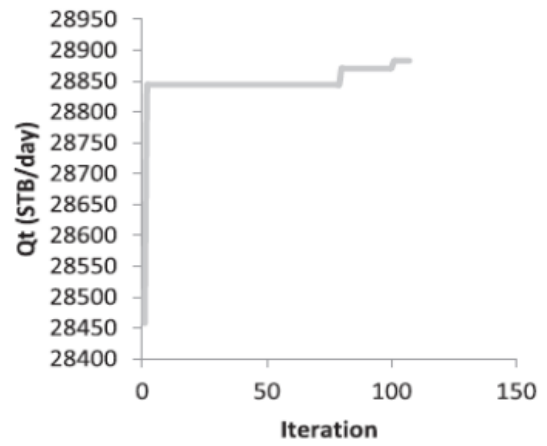


(a)

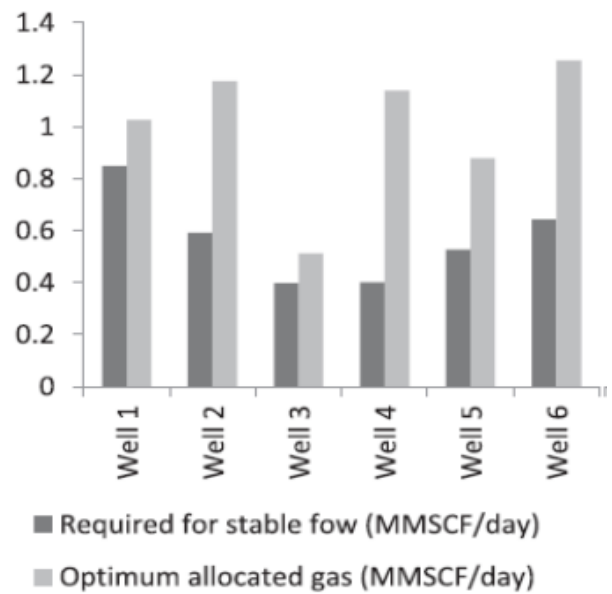


(b)

Figure 5. Gas allocation optimization of 4.5 MMSCF/day maximum available lift gas (a) convergence to optimum points (b) gas allocated optimum point.

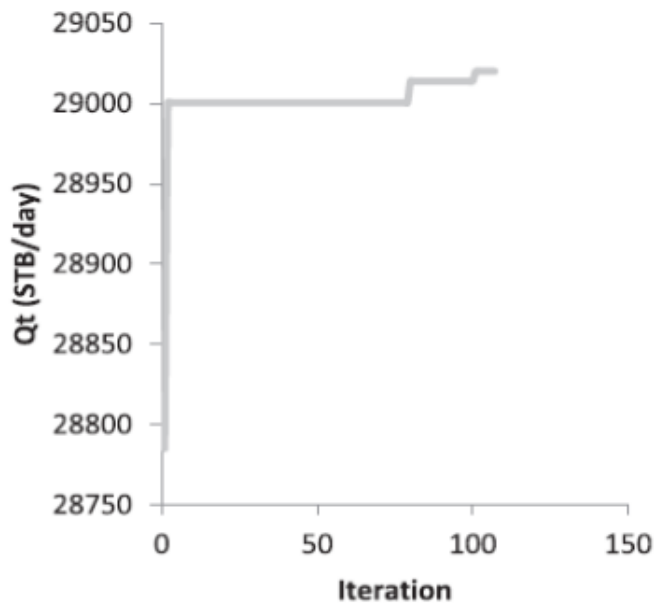


(a)

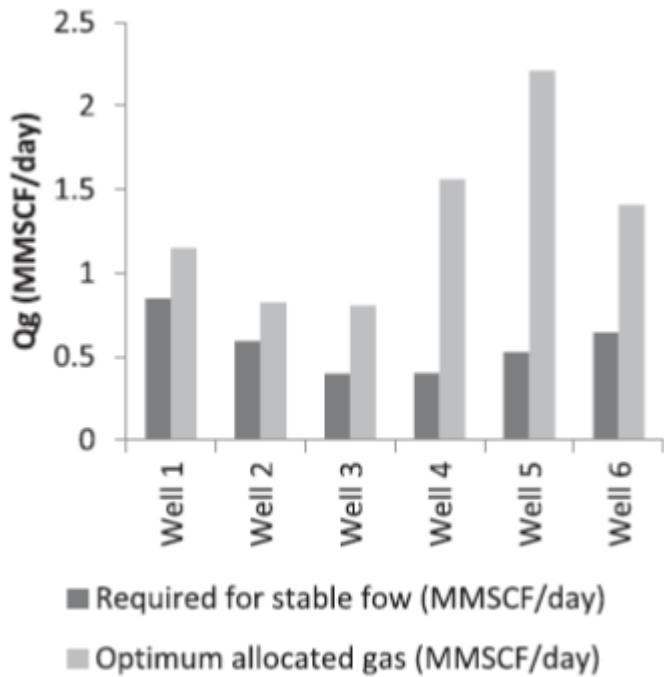


(b)

Figure 6. Gas allocation optimization of 6 MMSCF/day maximum available lift gas (a) convergence to optimum points (b) gas allocated optimum point.



(a)



(b)

Figure 7. Gas allocation optimization of 8 MMSCF/day maximum available lift gas (a) convergence to optimum points (b) gas allocated optimum point

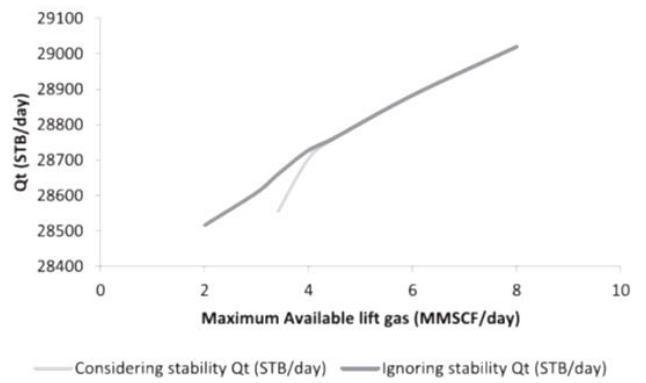


Figure 8. Considering and ignoring stability in gas allocation optimization for different maximum available lift gas

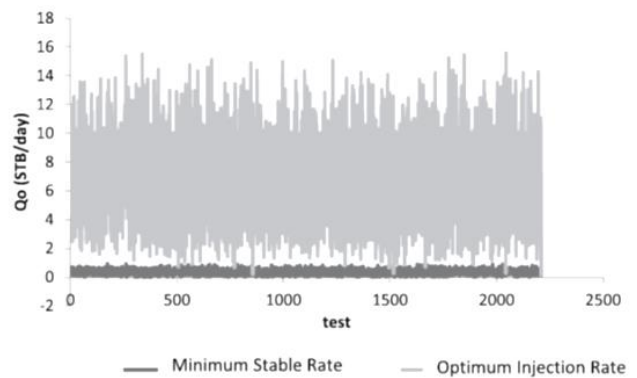


Figure 9. Optimum and minimum injection rate required for stability in different tests.

IV. CONCLUSION

1. The amount of production loss that considering stability causes is very small; thus considering the stability as a constraint for the optimizer is a good way for escaping unstable flow.
2. Considering stability in gas allocation optimization with any amount of available lift gas does not increase the number of iterations of the optimizer to a great extent.
3. This study shows that even when the amount of available lift gas is near 1.6 times the minimum amount of required gas for stable flow, ignoring stability leads to an unstable point. Thus, it is highly recommended that, until about two times the minimum needed lift gas for stable flow, stability be considered in optimization.

4. In most cases increasing the value of available lift-gas to more than a specific value would make the optimum point stable. But this is not general and even when the amount of available lift gas is unlimited; it is possible that ignoring stability leads to an unstable optimum point.

Nomenclature

Ai	injection port size, ft2
API	oil gravity, API
Bg	FVF of gas at injection point
Di	injection depth, ft
Dt	tubing depth, ft
Dwell	well depth, ft
E	Orifice efficiency factor, 0.9
F1, F2	Asheim stability factors
g	acceleration of gravity, ft/s ²
GLR	gas liquid ratio, SCF/STB
IDc	casing inner diameter, in
IDt	tubing inner diameter, in
IFT	surface tension, dyne/cm
J	productivity index, scf/s.psi
ODt	tubing outer diameter, in
Orifice size	orifice size, 1/64 in
P	pressure, psi
Pav	average pressure, psi
Pc	critical pressure, psi
Pr	relative pressure, P/Pc
Pb	bubble point pressure, psi
Pdown	pressure at the down of the section, psi
PI	productivity index, STB/day/psi
PR	reservoir pressure, psi
pti	tubing flow pressure at
Pup	pressure at the up of the section, psi
Pwf	bottom well pressure in flowing condition, psi
Pwh	well head pressure, psi
qfi	flow rate of reservoir fluids at injection point, ft ³ /s
Qg	injected gas, MMSCF/day
qgi	flow rate of lift gas at injection point, ft ³ /s
qlsc	flow rate of liquids at standard conditions, scf/s
Qo	produced oil of each well, STB/day
Qt	total produced oil, STB/day
T	temperature, F

Tav	average temperature, F
Tc	critical temperature, R
Tdown	temperature at the down of the section, F
Tr	relative temperature T/Tc
TR	reservoir temperature, F
Tup	temperature at the up of the section, F
Twh	well head temperature, F
VC	gas conduit volume, ft ³
Vt	tubing volume downstream of gas injection point, ft ³
WC	water cut, %
gg	gas gravity
gginj	injection gas gravity
gw	water gravity
m _{do}	dead oil viscosity, cp
m _o	oil viscosity, cp
r _{oi}	l gravity, api
r _{fi}	reservoir fluid density at injection point, lbm/ft ³
rgi	lift-gas density at the injection point, lbm/ft ³
rgsc	lift-gas density at standard surface conditions, lbm/scf

Appendix. Nodal analysis in natural flow

To calculate the oil rate of a well, nodal analysis is used. For this means, first a fixed oil production rate is assumed, well head is considered as the top node and the well is divided into about 200 ft sections. Then an average pressure and temperature for the uppermost section are assumed and using the black oil correlations the fluid properties on the average pressure and temperature of the uppermost section are calculated. These correlations estimate the PVT properties of the fluid by some properties such as pressure, C temperature and its specific weight but not its composition. An C example of them are the equations which are used in this paper and listed in Table 2. Afterwards, using two phase flow correlations and temperature estimation methods, the temperature and pressure at the bottom of that section are calculated. There are different correlations (experimental and analytical) that can relate the pressure to rate in two phase flow pipes such as Ansari, Hagedorn-Brown, etc. for different problems (vertical flow, horizontal flow, different

gas liquid ratio). These correlations have different accuracy and run time, and based on the problem a suitable one should be selected. Similarly, for temperature estimation there are different correlations. Some consider the heat balance between fluid, pipe and earth, which represent an accurate estimation but huge runtime. In spite of that some equations are less accurate but faster and based on the problem they can be selected. Then, using the new temperature and pressure, average pressure and temperature and fluid properties at the average pressure and temperature are calculated and using new properties the temperature and pressure at the bottom of the section are calculated. This procedure is repeated until the pressure at the bottom of the section is converged to a fixed value. The pressure of the bottom

of the uppermost section is the top node pressure of the proceeding section and similar to the previous section, its bottom pressure is calculated. Calculating the pressure at the bottom of the sections continued until the bottom hole pressure of the well was calculated. After calculating the bottom hole pressure for a fixed rate, other production rates were assumed and their corresponding bottom hole pressure was calculated. Thus, the production rate versus bottom hole pressure (TPR) was determined. Cross plotting was done with the IPR equation (IPR). The result was the calculation of the production rate of a well with a determined gas lift injection rate. Fig. 10 shows the flowchart of nodal analysis.

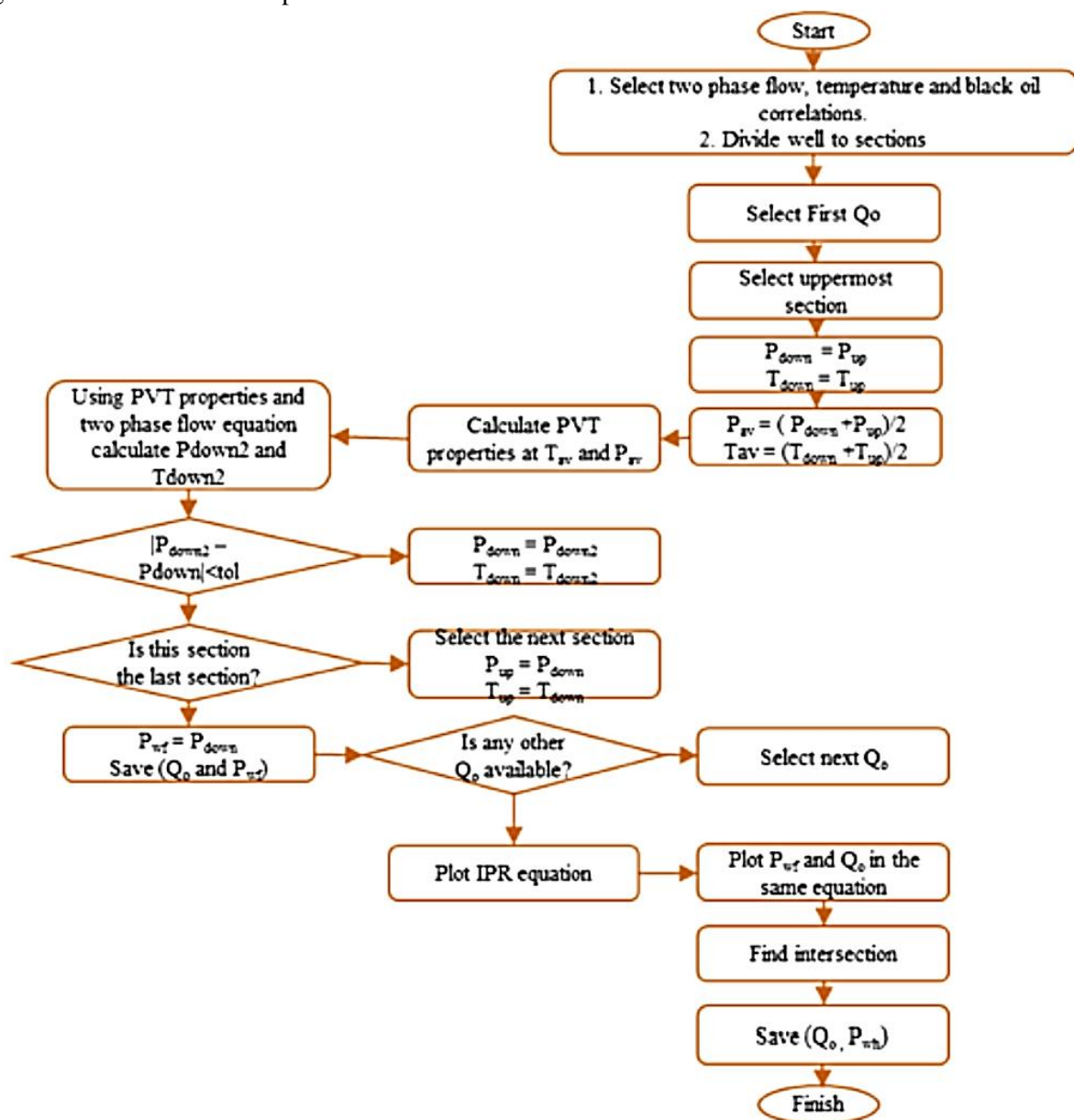


Figure 10. Flowchart of nodal analysis in natural flow

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