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

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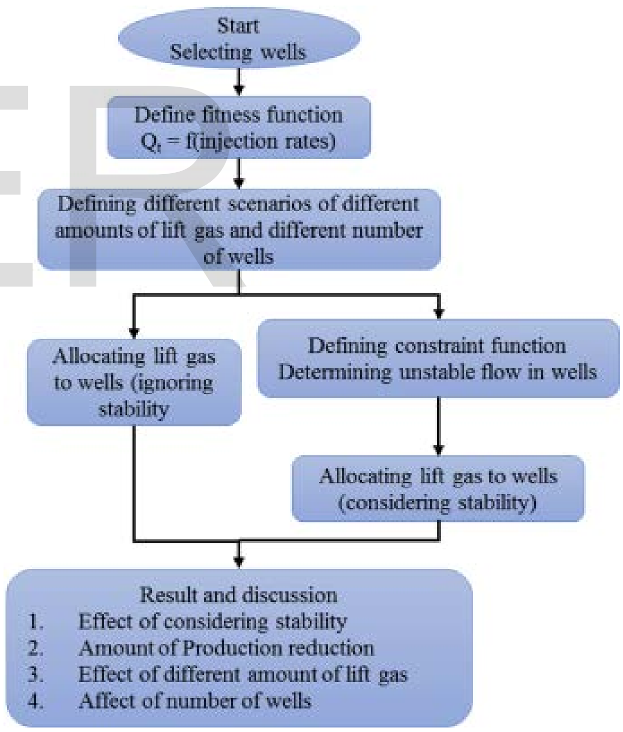
1.Introduction

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 (Jahanshahiet 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 (Bertuzziet al., 1953),introduced an equation to predict instability. Also in 1988, Blick (Blicket al., Novamber 19 88) pre-dicted the unstableflow using the Laplace transformation. In 2004,Fairuzov (Fairuzovet 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 (Poblanoet al., 2005) drew some maps to show the stable and unstable regions. In 2008,Eikrem (Eikremet al., 2008) introduced a dynamic model and using that plotted some stability maps. In 2011, Agiular (Aguilar andPoblano, 2011) studied the stability in the wells that are imposed to water conning. As well as in this year, Maijoni (Maijoniand 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.

2. 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 mathematicalmodel is required to predict the amount of total production, and later on the production of considering and ignoring stability willbe 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 theparameter 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 productionrate as output. The properties of the reservoir and wells are aboutthe range of the Iranian oilfields which can be seen in Table 1. In the fitness function, first the oil rate production of each wellshould be calculated. To calculate the oil rate of a well, nodalanalysis 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 correlationsforfluid andflow properties estimation. Here, forfluid properties, modeling the most accurate modelsbased on different literature (Brill and Beggs, 1991a) (Takacs, 1989)(Khamehchi, et al., 2009) have been used. For example, for critical pressure and temperature Standing (Vataniand Mokhatab, 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 respectivelyand solution gas oil ratio has been modeled by Laster (Lasater,1958a) equation. These equations are listed in Table 2. This tableshows the correlations for thefluid properties as well as a two phaseflow equation and a temperature estimation method. TheAnsari (Ansari et al., 1994) correlation is used for the two phaseflow and the Hasan-Kabir (Hasanand Kabir, Aug 1994) correlationis used for temperature estimation. This equation has very goodestimation and considers different parameters such as slippage andflow regime for theflow equation and the joule Thomson effect andheat balance in the temperature estimation equation. For moreinformation regarding these methods, refer to the references provided. In this calculation, different correlations were used. Theseare the most accurate ones based on different literature (Brill and Beggs, 1991b), (Takacs, 1989), (Pourafshary, 1979), (Bendakhliaand Aziz, 1989), (Renantoand Economides, 1998), (Patton et al.,Septamber 19 80). In order to apply the effect of gas lift, the gaslift effect is added by considering a different gas liquid ratio (GLR) inthe above injection point. It was previously mentioned that theinjected 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 wellas the effect of well in production, there is a need to involve theeffect of reservoir, and cross plot the results tofind 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 (GolanandWhitson, 1995). Its equation is shown inequation (1).



VSg=0.25VS + 0.333VSl

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

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

Fig. 1.Schematic of this paper's procedure.

	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

Table (1)
Well and Reservoir Data

It is assumed that the injection depth and the tubing size for each well during the gas lift operation is fixed and the only variableis the share of lift gas for each well. The result was the calculation of the production rate of a wellwith a determined lift gas injection rate. Now this procedure forother wells with their known gas injection rate is repeated and theoil rate production of each one is calculated. The production rates ofall the wells are added and the Q t (the sum of production rates asthe output of the ness function) is calculated. In summary, here thefitness 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

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

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

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

allocation was created. Inthe case of ignoring stability, using an optimizer algorithm like thegenetic 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).

Asheim introduced two factors F 1 and F 2 to distinguish thestable and unstable regions, and he said that theflow is stable if oneof F 1 or F 2 be higher than 1.

It is clear that in the Asheimequations 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 functionof 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 beforetesting the stability of theflow the units of parameters are changedto Asheim and then F 1 and F 2 are calculated.In this part, the wells are initially introduced, and then a modefor predicting the total oil production of a specific injection iscreated. Finally, another model for forecasting the instability ismade. In the next section, these models will be optimized and theeffect of considering stability will be discussed.

	Natural flow		Unlimited Available Gas		Equal Injection Rate		Production Weight Injection Rate		G. A.	
	qg (MM SCF	q_o (STB/D)	qg (MMSCF /D)	q_o (STB/D)	qg (MMSC F/D)	q_o (STB/D)	qg (MMSC F/D)	q_o (STB/D)	qg (MMS CF/D)	q_o (STB/D)

	/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
WELL5	0	2300	6	3215	1.6	2650	1.55	2645	0.2	2450
Total		**12460**	**23.5**	**18610**	**8**	**15730**	**8**	**15755**	**8**	**16465**

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

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

In this section, the effect of considering stability as a constraintin different cases of gas allocation optimization will be discussed.Thus, between the six assumed wells, the assumed available lift-gashas been allocated in an optimum way.It is clear that when we have a fixed amount of lift gas and wewant to allocate it between different wells, there are myriad waysfor this allocation. Two kinds of optimum allocation can be defined,one in which the net profit maximizes and the second in which thetotal produced oil maximizes (Alarc_on et al., 2002). In this study, as
the wells properties cannot be changed and the compressor is fixedand is working with constant power; the net profit corresponds tototal oil production. Hence, the problem of

this study is to allocate afixed amount of lift gas between some previously defined wells in away that the total oil production be maximized and have a stable flow.

The Genetic algorithm (GA) has been used as an optimizer andits parameters can be seen in Table 3. The Genetic algorithm is aheuristic optimization algorithm and works well in complexproblems (in which many parameters change simultaneously). Therefore, it has been selected to be used here. The chromosome orindividuals of the optimizer are combinations of the gas injectionrates of different wells. These individuals are initially created on arandom basis. Then, in every iteration, all the individuals areevaluated and if some of them violate the constraint, they are penalized. Afterwards the best four individuals (with higher accumulatedrates) go directly to the next generation (elite count) aswell as for the next generations, some other individuals aregenerated by cross over and mutation. Then, it is checked whetherthe 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 itsconvergence figure) the optimum point is found.

To add the stability constraint to the problem, first of all for eachwell the value of F1 and F2 for different amounts of available lift gas(starting from zero and gradually increasing it) have been calculatedand so the minimum value of lift gas to have the stable flowhas been found. These values are listed in Table 4. The last row ofTable 4 shows that the sum of all Qg is equal to 3.411, and it is clearthat the amount of lift gas should be at least this amount to makethe stable flow possible otherwise at least one well would producein 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 eachcase, the gas allocation optimization has been run two times. Atfirst, the stability has been considered and in the second case it hasbeen ignored. Finally, the results have been compared.

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 (3)
Physical Properties Correlations

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

4. Results and discussions:

For studying the effect of considering stability on the optimumpoint, different amounts of available lift gas have been assumed andtheir optimum points by considering and ignoring stability havebeen calculated and compared. In this problem we may

Sum of all injection rates 3.411

considerthe minimum amount of needed lift gas that make all wells produce in stable flow as 3.411 MMSCF/day. Thus there are three differentconditions for maximum available lift gas. Having less than 3.411MMSCF/day, equal to that and more than that.

4.1. Available lift gas less than 2 MMSCF/day

In the beginning, 2 MMSCF/DAYgas 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

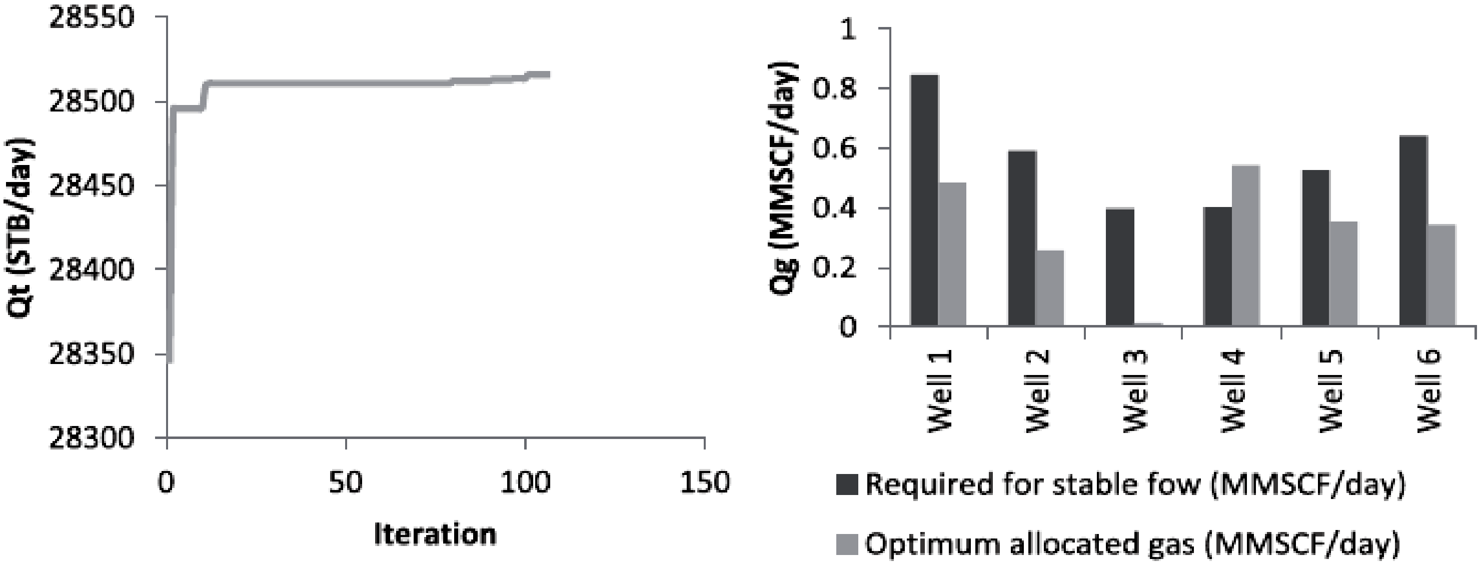
The next step is 3.411 MMSCF/DAY available lift gas, this valueis the sum of all minimum required lift gas for the stable flow ofeach well. Fig. 3 shows theconvergence of the optimum point inthe case of ignoring stability. It is similar to the previous cases ifstability be considered, there is just one point that the algorithmshould find, thus it is impossible or very hard for the algorithm tofind. so the algorithm for optimizing this case (considering stability)has not found any acceptable solution. In Fig. 3 only theconvergence of ignoring stability is shown. Fig. 3(b) shows theoptimum points, and in the case of ignoring stability 2 wells areunstable.

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 beseen in this figure, in ignoring stability, the algorithm has searcheda 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 algorithmis ignored, the difference of available lift gas with therequired lift gas for stable flow is small and most wells will be in anunstable region. But if the amount of available gas increases, thesituation is different. This is clear because considering stability addsa lower limit for injection rate. Fig. 5 shows the convergence ofconsidering and ignoring optimization for the amount of 4.5MMSCF/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 tosuppose 6 MMSCF/day for available gas. Fig. 6 shows the convergence of the optimum gas allocation by ignoring stability, and it canbe seen that it has searched a wide space to reach the optimumpoint and even ignoring the stability has led to a stable optimumpoint. The optimum point is shown in Fig. 6(b), and this figureshows that all wells are in stable region. It seems that a furtherincrease in the value of the available lift gas will cause the optimumpoint to fall in stable region (even if stability is ignored in optimization).To make sure, another point with 8 MMSCF/day availablelift 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 theavailable gas has made the optimum point farther than stablebound.

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

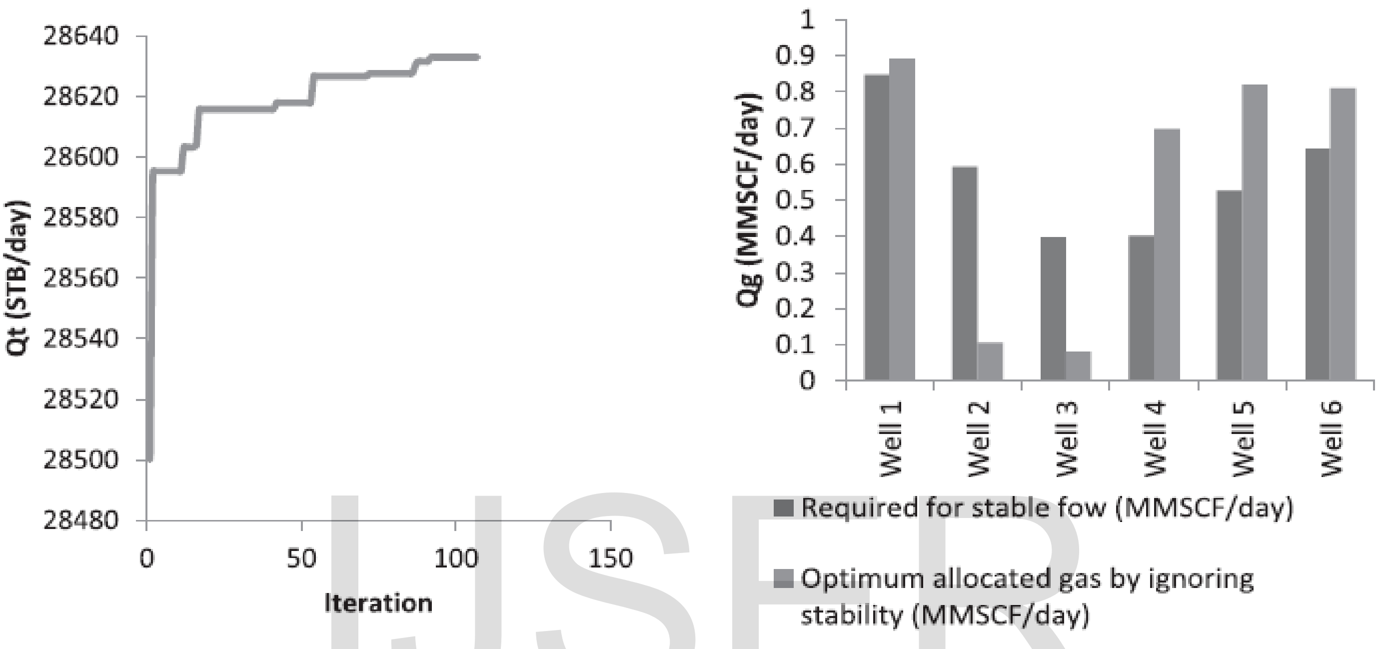
Fig. 8 shows the difference of the total oil production betweenconsidering and ignoring stability in optimization for differentamounts of available lift gas, this figure shows that if the amount ofavailable lift gas be less than a specific value (in this study 3.411MMSCF/day) there is no stable flow. Having maximum available liftgas between 3.411 and 5 MMSCF/day (in this study) causes theoptimum points of considering and ignoring stability to be differentand having more than 5 MMSCF/day lift gas makes both optimumpoints of considering and ignoring stabilities coincide. Thus itshould be considered that if the amount of available lift gas is neardouble (actually 1.6), the minimum amount of required gas forstable flow, considering and ignoring stability, will lead to differentsolutions.It should be mentioned that in all of the above cases, consideringand ignoring stability, the optimizer needs a similarnumberof iterations to find the optimum point. In the above figures, theeffect of considering and ignoring stability when we have adifferent amount of available lift gas is illustrated. Using them, theconvergence of the optimization algorithm in these cases can becompared. The effect of considering stability on optimum allocation can be seen and the influence of the amount of available liftgas on the stable and unstable optimum points can be observed. Itis clear that the value of the injected gas should be more than aspecific value to have a stable flow, but the question is that whether increasing the amount of lift gas to more than a specificvalue, in all cases would lead the optimum point of ignoring thestability to the stable region or not? to answer this question, somewells with the properties of the range of Table 1 are assumed.Then by the worst assumption, with an unlimited amount of liftgas, an attempt is made to find a well in which the amount ofrequired gas for its optimum point be less than the minimumrequired gas for stable flow. In this part, the meaning of the optimumpoint is a point that the injected gas maximizes its oilproduction and increasing or decreasing the amount of lift gasdecreases its production oil rate. If such a well exists in any groupof wells, its optimum gas share would be less or equal to its unlimitedoptimum point and would have an unstable flow. Fig. 9shows the optimum and required amount of lift gas for differentwells. It shows that after 2211 tests such a well is found. Its optimumrate of injection gas rate for unlimitedavailable gas was0.18 MMSCF/DAY but less than 0.42 MMSCF/DAY causes an unstableflow. Also before that point, in 7 cases the value of optimumpoint 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 tomore than a specific value, the probability of the optimum point(ignoring stability) to



(a) (b)

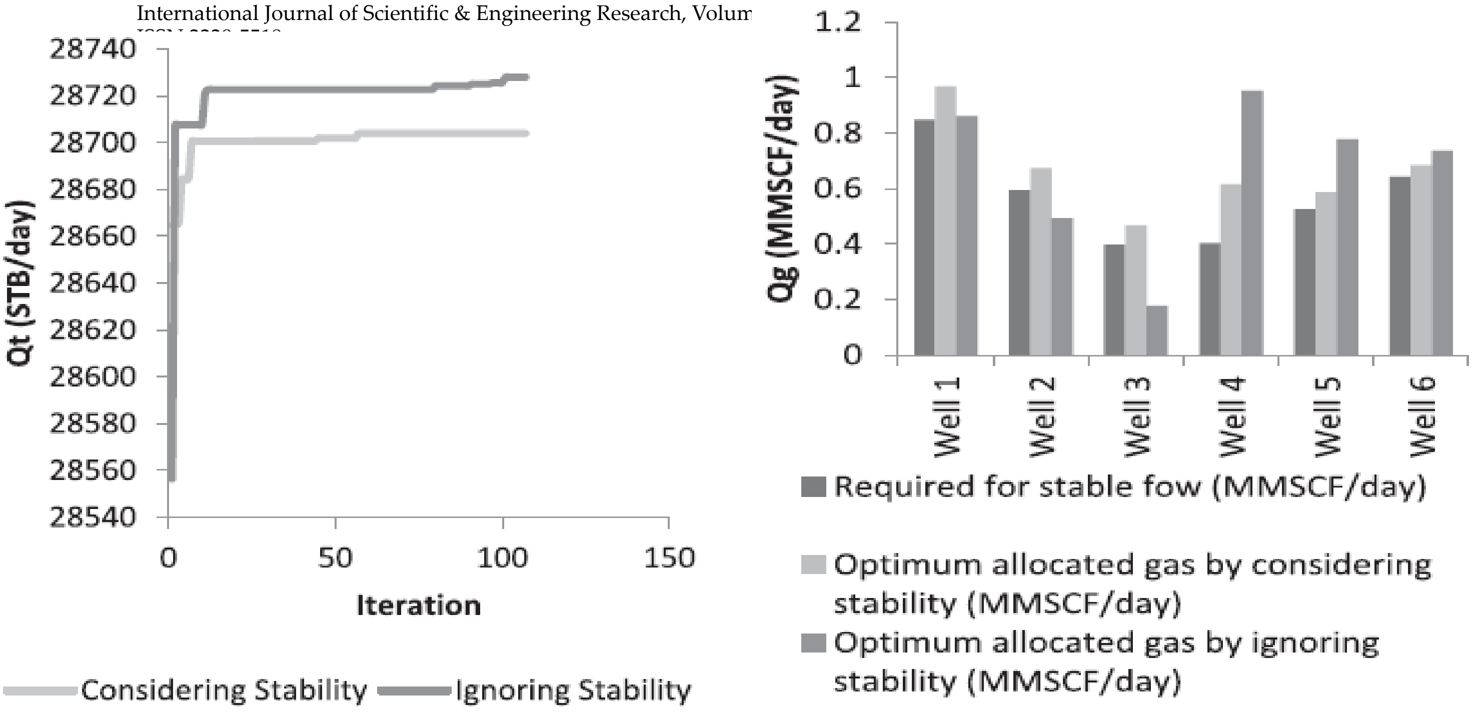
fall in an unstable region decreases, but asshown it is definitely not zero..

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



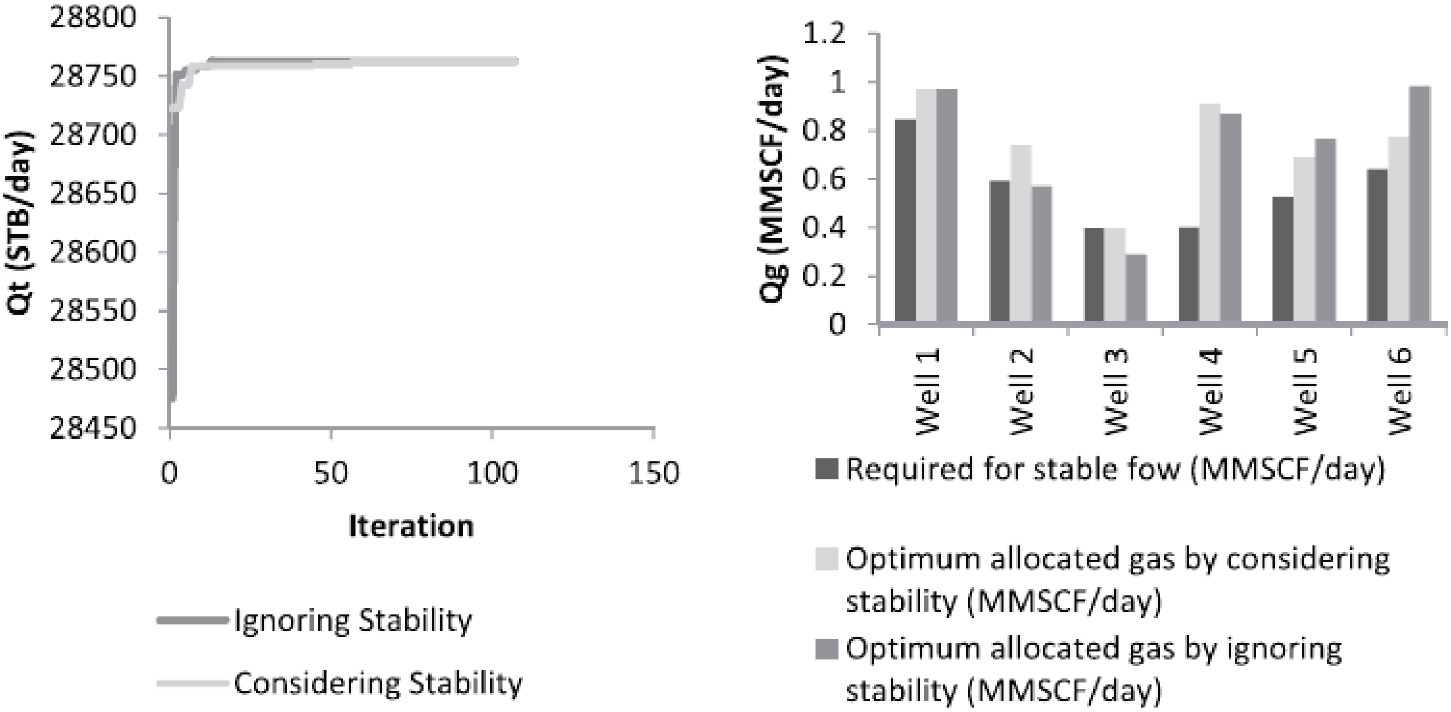
(a) (b)

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



(a) (b)

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



(a) (b)

Fig. 5. Gas allocation optimization of 4.5 MMSCF/day maximum available lift gas (a)

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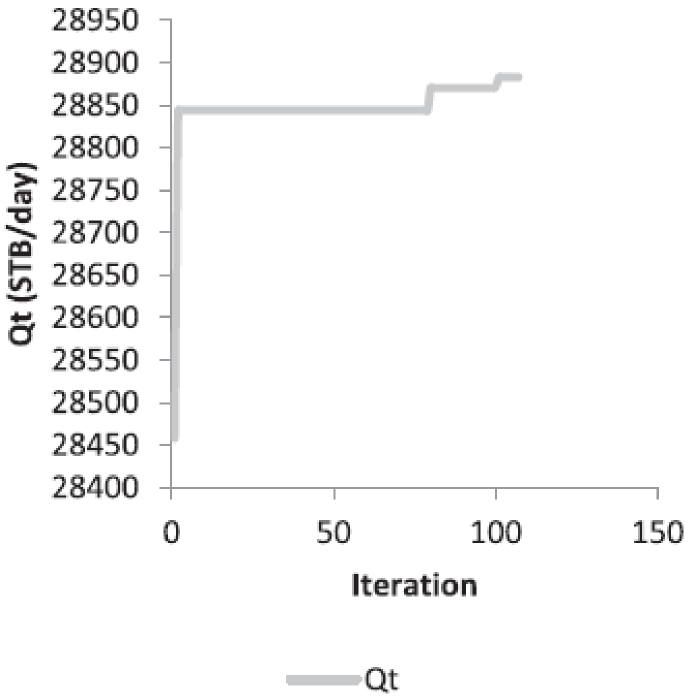
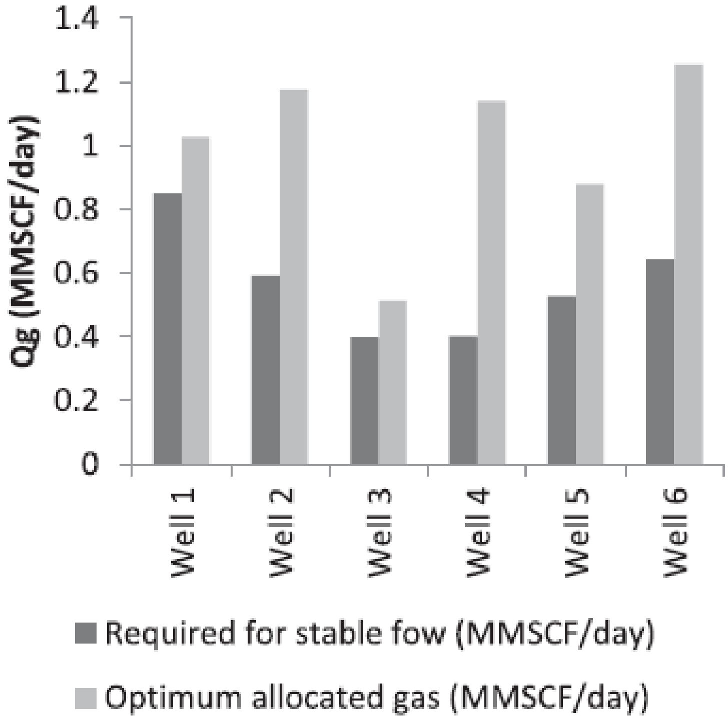
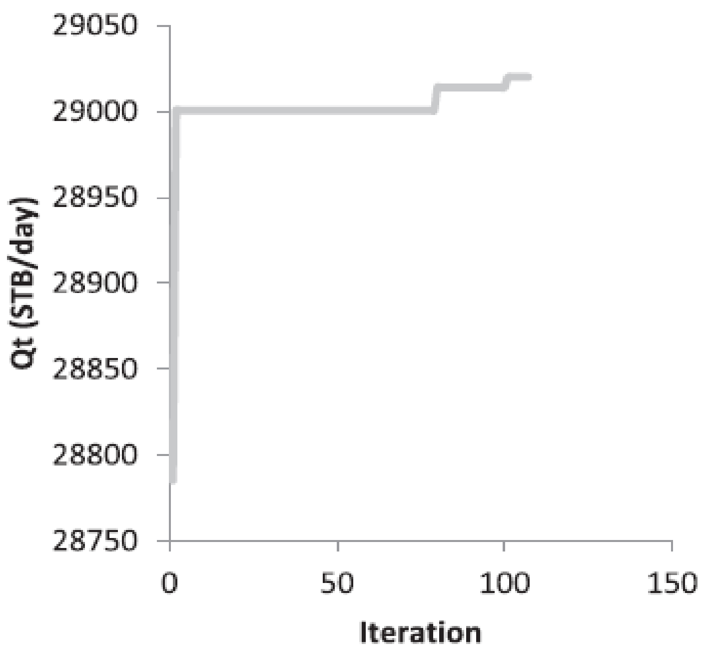


(a)

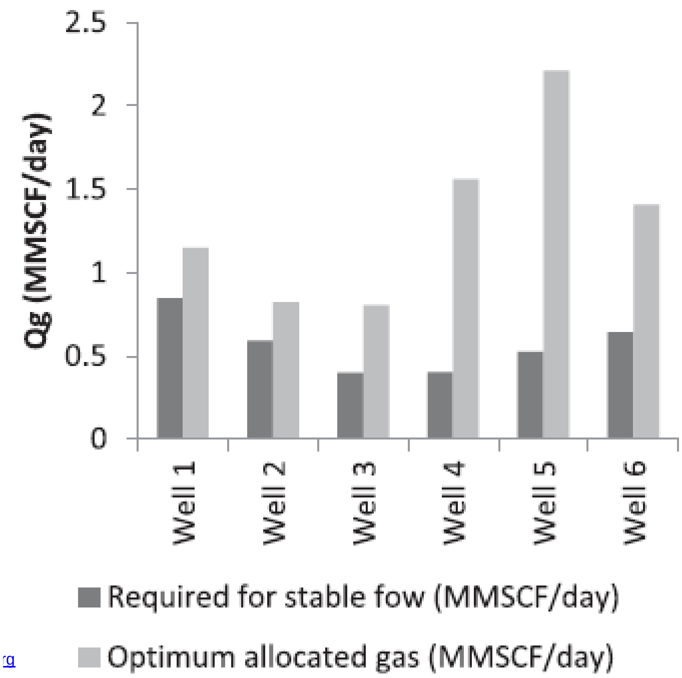


(b)

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



(a)



(b)

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

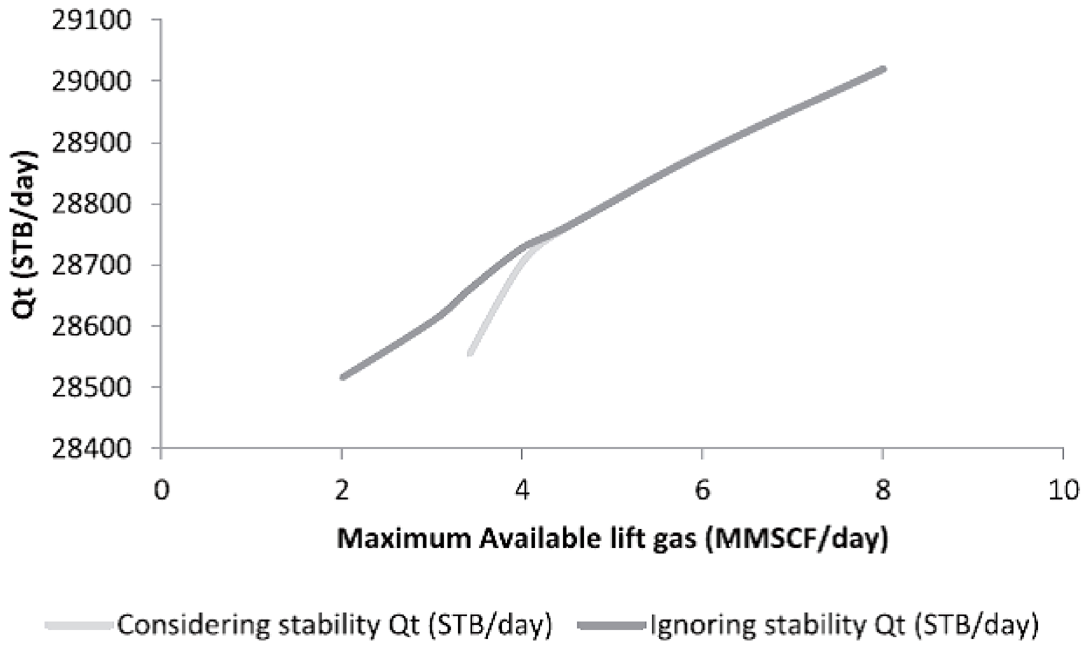


Fig. 8. Considering and ignoring stability in gas allocation optimization for different maximum available lift gas

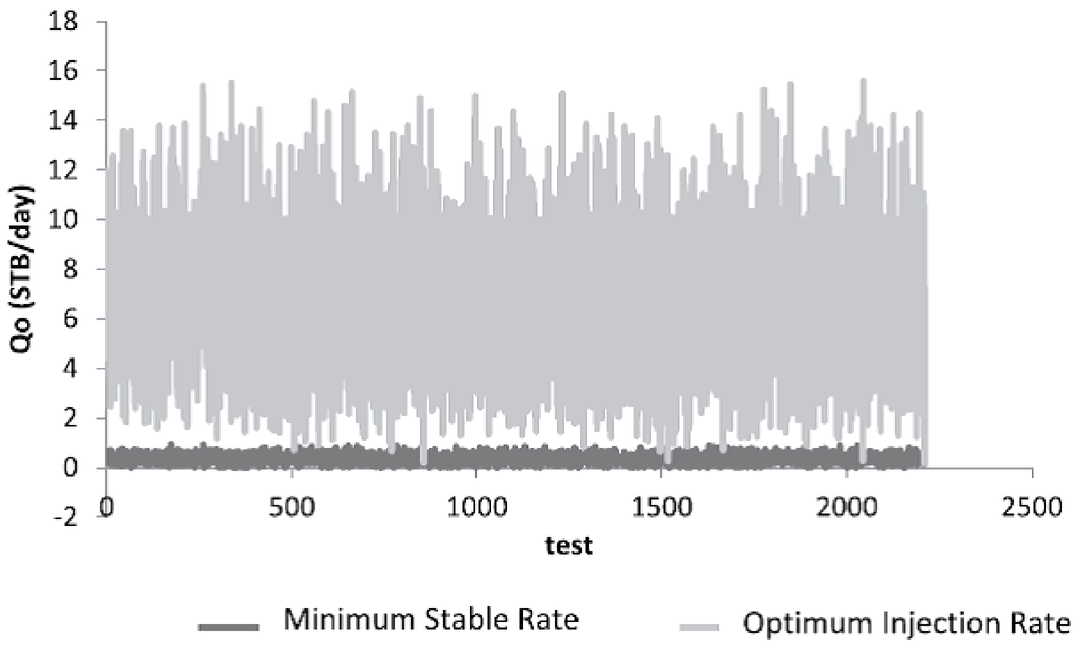


Fig. 9. Optimum and minimum injection rate required for stability in different tests.

5. Conclusion

1. The amount of production loss that considering stability causesis very small; thus considering the stability as a constraint forthe optimizer is a good way for escaping unstable flow.

2. Considering stability in gas allocation optimization with anyamount of available lift gas does not increase the number ofiterations of the optimizer to a great extent.

3. This study shows that even when the amount of available lift gasis near 1.6 times the minimum amount of required gas for stableflow, ignoring stability leads to an unstable point. Thus, it ishighly recommended that, until about two times the minimumneeded lift gas for stable flow, stability be considered inoptimization.

4. In most cases increasing the value of available lift-gas to morethan a specific value would make the optimum point stable. Butthis is not general and evenwhen the amount of available lift gasis unlimited; it is possible that ignoring stability leads to anunstable optimum point.

Nomenclature

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Ai injection port size, ft2

API oil gravity, API

BgFVF of gas at injection point

Di injection depth, ft

Dttubing depth, ft

Dwell well depth, ft

E Orifice efficiency factor, 0.9

F1, F2Asheim stability factors

gacceleration of gravity, ft/s2

GLR gas liquid ratio, SCF/STB

IDccasing 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

Pavaverage pressure, psi

Pc critical pressure, psi

Pr relative pressure, P/Pc

Pbbubble point pressure, psi

Pdown pressure at the down of the section, psi

PI productivity index, STB/day/psi

PR reservoir pressure, psi

ptitubing 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

qfiflow rate of reservoir fluids at injection point, ft3/s

Qg injected gas, MMSCF/day

qgiflow rate of lift gas at injection point, ft3/s

qlscflow rate of liquids at standard conditions, scf/s

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Qoproduced oil of each well, STB/day

Qt total produced oil, STB/day

T temperature, F

Tavaverage temperature, F

Tc critical temperature, R

Tdown temperature at the down of the section, F

Trrelative temperature T/Tc

TR reservoir temperature, F

Tup temperature at the up of the section, F

Twhwell head temperature, F

VC gas conduit volume, ft3

Vt tubing volume downstream of gas injection point, ft3

WC water cut, %

gggas gravity

gginjinjection gas gravity

gwwater gravity

mdodead oil viscosity, cp

mo oil viscosity, cp

roil gravity, api

rfi reservoir fluid density at injection point, lbm,ft3

rgi lift-gas density at the injection point, lbm/ft3

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 thismeans, first a fixed oil production rate is assumed, well head isconsidered as the top node and the well is divided into about 200 ftsections. Then an average pressure and temperature for the uppermost section are assumed and using the black oil correlationsthe fluid properties on the average pressure and temperature of theuppermost section are calculated. These correlationsestimate thePVT 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 andlisted in Table 2. Afterwards, using two phase flow correlations andtemperature 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 pressureto 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 runtime, and based on the problem a suitable one should be selected.Similarly, for temperature estimation there are differentcorrelations. Some consider the heat balance between fluid, pipeand earth, which represent an accurate estimation but huge runtime.In spite of that some equations are less accurate but faster andbased on the problem they can be selected. Then, using the newtemperature and pressure, average pressure and temperature andfluid properties at the average pressure and temperature arecalculated and using new properties the temperature and pressureat the bottom of the section are calculated. This procedure is repeated until the pressure at the bottom of the section isconverged to a fixed value. The pressure of the bottom of the uppermostsection is the top node pressure of the proceeding sectionand similar to the previous section, its bottom pressure is calculated.Calculating the pressure at the bottom of the sectionscontinued 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 correspondingbottom hole pressure was calculated. Thus, the production rateversus bottom hole pressure (TPR) was determined. Cross plottingwas done with the IPR equation (IPR). The resultwas the calculation of the production rate of a well with a determined gas lift injectionrate. Fig. 10 shows the flowchart of nodal analysis.

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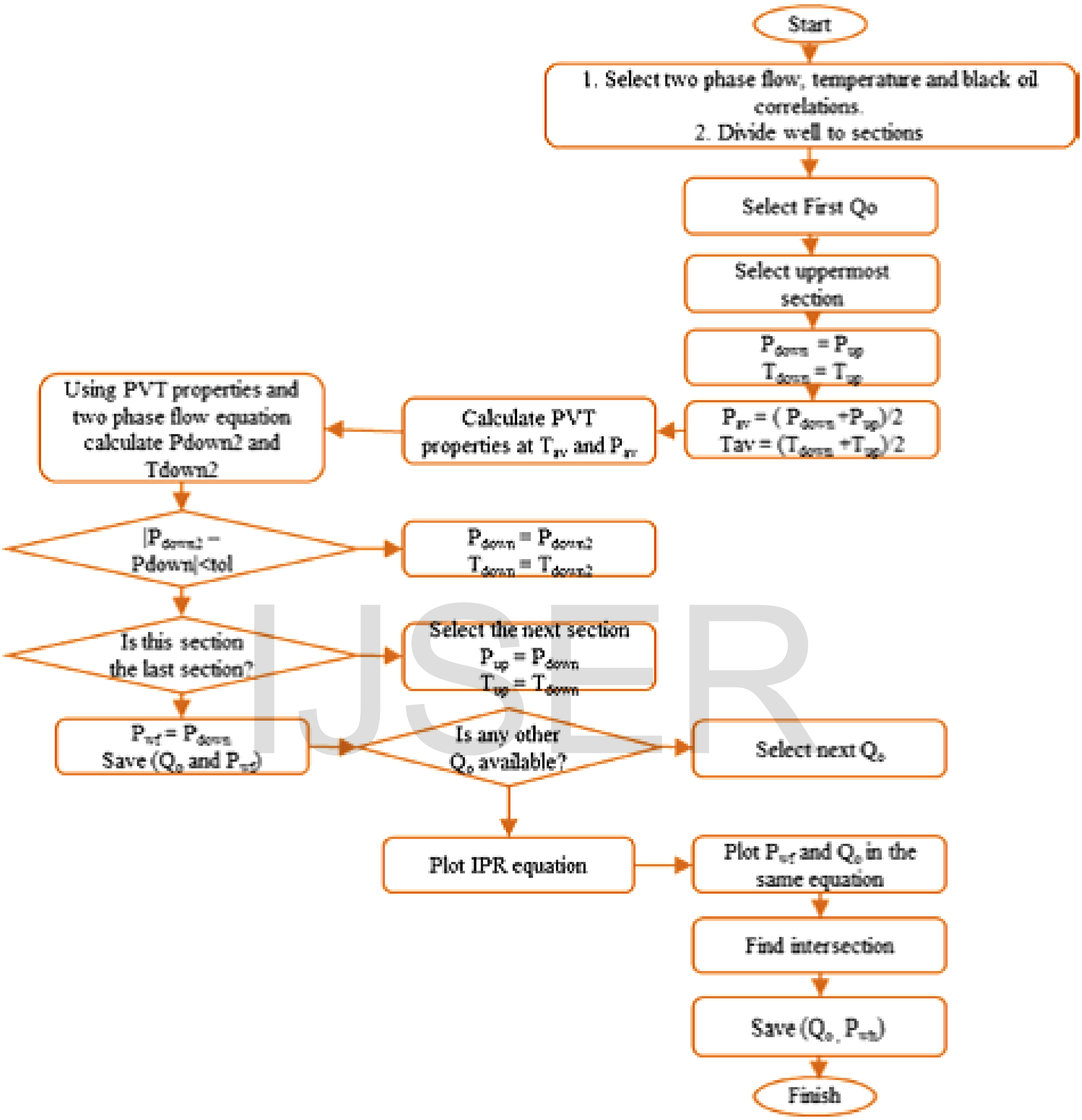

Fig. 10. Flowchart of nodal analysis in natural flow

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