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Improved Stable, Optimal Production in Gas Lift Wells: Exploiting Additional Degrees of Freedom

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Abstract: Typical production objectives in lift gas assisted oil wells include stable and optimal production. These objectives are normally daunted by the presence of unstable dynamic behavior resulting from interplay between the energies in the casing head and tubing head of the wells. Moreover, realistic constraints on compressor power and sufficient lift gas availability need to be considered to determine the optimal production from the wells. This paper proposes an alternate optimization formulation to reflect these realistic constraints and exploit the additional degree of freedom associated with the production choke opening. It is demonstrated that a co-ordinated functioning of the choke with the lift gas flow can result in improved and stable production. To overcome the limitations of corrupt measurements in the uncertain downhole environment, we propose the use of a statistical estimator. Validation results involving the simulation model of Jahanshahi *et al.*, (2012) point to the efficacy of the proposed optimization model as well as the soft-sensing approach for estimating downhole pressures.

Keywords: Optimization, Lift Gas Assisted Oil Wells, Soft sensing, Projection to Latent Structures

1. INTRODUCTION

With declining reservoir pressures, mature oil fields lack the ability to produce oil naturally, and hence artificial lift techniques are applied to enhance production. Gas lift is one such mechanism. In such an assist mechanism, gas is injected deep into the tubing of the associated gas wells to reduce the density of fluid in the tubing. This reduces the downhole pressure, thereby creating favourable pressure distributions across the flow path, and results in enhancing production. Favourable pressure distributions and drive mechanisms can also be facilitated upstream of the wells through the water flooding approach. The overall functioning of the wells using such assist mechanisms is daunted by significant uncertainties related to production parameters, lack of robust sensors, and relatively limited understanding of the cause-effect relationships. Process systems engineering tools such as modeling, optimization, and control can help to address some of these challenges, and an excellent overview can be found in Chen *et al.*, (2011) and Foss, (2011).

Allocation of limited lift gas to multiple wells, and the control of instability phenomena in the wells are problems of increasing research interest. Alacrón *et al.*, (2002), Buitrago *et al.*, (1996), Kanu *et al.*, (1981), and Nishikiori *et al.*, (1989) worked on the problem of optimally allocating a limited quantity of lift gas to a system of wells on a well pad to maximize production. The optimization was based on a steady state characterization, i.e. the Gas Lift Performance Curves (GLPCs), of wells which are empirical non-linear curves unique to a well that relate the production rate from wells to the lift gas injection rate at fixed production choke opening (see Figure 1).

Gas lifted wells are prone to instabilities in the oil flow that result from a dynamic interplay between gas in the casing and multiphase fluid in the tubing. Eikrem *et al.*, (2008) modelled the casing heading instability present in lift gas assisted wells. It is characterized by severe oscillations in production from the well with a time period of a few hours. They implemented control strategies using the production choke as a manipulated variable and the downhole pressure as a controlled variable (see Figure 1). The control task could be challenging due to lack of robust sensors for the downhole pressures, which could affect control performance. Aamo *et al.*, (2004), Eikrem *et al.*, (2004), and Scibilia *et al.*, (2008) therefore proposed the need for online state estimation of downhole pressure values since the harsh environments near the bottom-hole make sensor readings highly unreliable. Each of the above approaches has used model-based online state estimation schemes. However, in the presence of significant uncertainties in the well behaviour, the fidelity of the model could play a crucial role in generating accurate estimates.

Jahanshahi *et al.*, (2012), proposed a more realistic well model which accounted for pressure losses due to friction; they also explored the possibility of using the gas choke opening in addition to production choke opening for control purposes to eliminate the casing heading instability. They concluded that no significant advantage in control was achieved on using the additional variable. The advantage of using the gas choke opening, however, under conditions of limited gas availability needs to be more carefully analysed.

The aforementioned approaches towards control for stable production function on relatively shorter time scales. In contrast, the GLPC based approach uses steady state characterization of the lift gas to production flow rates, and is relatively focused on a large time scale. Two aspects may compel the need to consider optimality at time scales that are intermediate. The first is the availability of lift gas, which may be limited due to fiscal constraints, limitations on compressor power or the need to supply lift-gas to several wells on a well pad. The second aspect is related to the initiation of instabilities which can jointly be addressed by bringing the choke opening as an additional degree of freedom along with the lift gas flow in a dynamic fashion.

This paper addresses the above mentioned issues through the formulation of an optimization problem that integrates across the aforementioned time scales, and addresses the variability encountered at each of them. We show that under constraints of limited lift gas availability, the production choke opening indeed provides additional flexibility to achieve optimal production targets while eliminating casing heading instability. The casing heading instability is represented in the optimization formulation in terms of an instability index (appropriately defined over a horizon) on which a threshold is specified, and included in the set of constraints. Furthermore, considering the availability of additional pressure measurements at different points along the well (potentially correlated), the paper explores the use of the statistical Projection to Latent Structures (PLS) based estimator instead of the model based approach. The former approach could leverage developments in Errors-in-Variables (EIV) formulations to generate relatively robust estimates in the presence of significant noise / uncertainty for use in closed loop control. Simulation results involving the dynamic model proposed in Jahanshahi *et al.*, (2012) demonstrate the potential and utility of the proposed optimization approach to achieve higher production while alleviating the casing head instabilities.

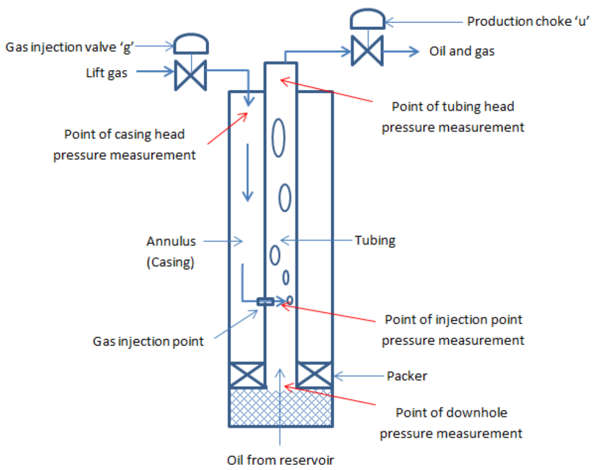

Figure 1: Schematic of a lift gas assisted oil well

The rest of the paper is structured as follows. In Section 2, we introduce the optimization problem by motivating the need to consider both gas valve opening and production choke opening as degrees of freedom. We then formulate the optimization problem with constraints. We introduce an index to quantify the casing head instability. In Section 3, we discuss the development of a statistics based sensor for the estimation of the downhole pressure, using the method of Projection to Latent Structures and we discuss the Error in Variables formulation. A case study is presented in Section 4 that highlights the utility of the optimization formulation, followed by conclusions in Section 5.

2. THE OPTIMIZATION PROBLEM

The problems of optimal allocation of lift gas to wells and the elimination of instabilities in them have often been dealt with in a time-wise hierarchical fashion (Nikolau *et al.*, 2006), and hence have been studied as dissociated problems in literature. The base layer control (with a time frame of seconds) to stabilize the well is viewed as a lower layer of decision making, while the optimization of gas allocation (on a relatively longer time frame, like weeks or months) is a relatively higher layer. This hierarchical approach to decision making could potentially miss out on some dynamic degrees of freedom that can provide improved performance at the lower levels of decision making. Here we explore an alternate approach with a view to providing additional flexibility to enhance production while limiting the casing heading instability.

2.1 Motivating example for integrating time scales

Optimization of lift gas flow allocation based on GLPC curves is generally performed using steady state considerations, and could have associated limitations. The GLPC of a well is traditionally generated assuming a fixed (generally full) production choke opening. However, it is important to note that the production choke also plays a major role in stabilizing the well, and hence its values are manipulated to alleviate casing heading instabilities. These manipulations shift the operation of the well to a different GLPC. Therefore, the onset of instabilities and subsequent manipulation of production choke will render the allocation of gas lift flow based on a former GLPC to be sub-optimal with respect to the production objectives. To illustrate this, Figure 2 shows the results generated from simulations performed using the model proposed by Jahanshahi *et al.*, (2012) generated at three different production choke openings u. It can be seen that the peak in production shifts to the left with a decrease in production choke opening. Therefore, if the incumbent operation at a production choke opening of 0.4 exhibits instabilities, and is alleviated by reducing the choke opening to 0.3, the well will now shift to a different GLPC and the gas allocation vis-a-vis the production is no longer optimal.

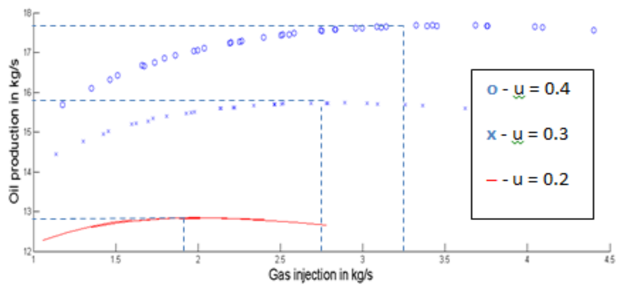

Figure 2: GLPCs at different choke openings

In order to overcome this potential loss of optimality, in this paper, we propose to merge these two problems spread across different time scales by formulating an optimization problem with the objective of increasing production while simultaneously alleviating the casing heading instability. It is, therefore, essential to study the combined effect of manipulating the values of production choke opening (u) and gas injection valve opening (g) on the production of oil from the well. Simulations using the well model were used to create the 3D plot in Figure 3 of production w_{po} vs. gas injection valve opening and production choke opening. For each gas valve opening value, the production falls steeply at a certain value of choke opening. This is indicative of the lack of gas to maintain stable flow at that production choke opening, and a resultant transition of the well from stable to unstable flow regime, as a result of which a loss in average production is observed.

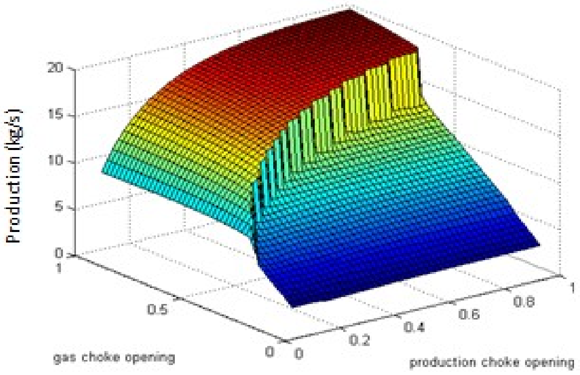

Figure 3: 3D plot of oil production rate vs. gas choke opening and production choke opening

2.2 Problem formulation

Considering that the usual objective pertaining to oil fields is to maximize the net production of oil, the optimization problem can be formulated as:

$$\max_{u,g}\left(\sum_{k=1}^{N} w_{k,po}\right) \tag{1}$$

where, $w_{k,po}$ is the production from the k^{th} well (in kg/s, or barrels per day in traditional practice), and u and g are the production choke opening and the gas injection valve opening (with values between 0 and 1), respectively. N is the number of wells on the pad. The decision space chosen for this optimization problem consists of u and g, since an optimal combination of these variables can determine both stability and optimality of the production.

This optimization, however, must respect certain constraints, which can be written for each individual well (and hence dropping the index k). The constraints can be written as follows:

a. The first principles model for each well must be satisfied:

$$\frac{dx_1}{dt} = w_{gc} - w_{iv} \tag{2}$$

$$\frac{dx_2}{dt} = w_{iv} + w_{rg} - w_{pg} \tag{3}$$

$$\frac{dx_3}{dt} = w_{ro} - w_{po} \tag{4}$$

In the above governing equations for the well behaviour, x_1, x_2 and x_3 are the states of the model, which are respectively the mass of gas in the casing, the mass of gas in the tubing and the mass of oil in the tubing. w_{gc} is the flow rate of gas entering the well, w_{iv} is the flow rate of gas entering the tubing from the casing, w_{rg} and w_{ro} are the flow rates of gas and oil respectively exiting the reservoir and entering the well tubing, w_{pg} and w_{po} are the flow rates of gas and oil exiting the well through the production choke respectively. The decisions u and g affect the pressure profiles across the production choke and along the well tubing, and thereby influence the production rates and the onset of instability. In this formulation, we use the relationships described in Jahanshahi *et al.*, (2012) to represent these influences; these relationships are not reproduced here for brevity and the reader is directed to the paper by Jahanshahi *et al.*, (2012) for further details. In the event of multiple wells present, this constraint will apply to each of the wells.

b. As discussed earlier, we are limited by the amount of gas we can use for artificial lift purposes, and hence we must place a constraint on the quantity of injected gas (in kg/s) as follows:

$$w_{gc} \le w_{gas,available} \tag{5}$$

where, $w_{gas,available}$ is the amount of lift gas available. For a particular well the injected gas is related to the gas injection valve opening g by,

$$w_{gc} = K_{gs} g \sqrt{\rho_{G,in} \max\left(P_{GS} - P_{AT}, 0\right)} \tag{6}$$

where, K_{gs} is the gas lift choke constant, g is the gas lift choke opening, $\rho_{G,in}$ is the density of gas entering the casing, P_{GS} is the gas source (compressor) pressure, P_{AT} is the pressure at the top of the annulus. Hence we can write:

$$K_{gs} g \sqrt{\rho_{G,in} \max\left(P_{GS} - P_{AT}, 0\right)} \le w_{gas,available} \tag{7}$$

In the event of multiple wells, the sum of all the N values of gas injection rates (for N wells) would have to be limited by the maximum availability, i.e.

$$\sum_{k=1}^{N} K_{k,gs} g_k \sqrt{\rho_{k,G,in} \max\left(P_{k,GS} - P_{k,AT}, 0\right)} \le w_{gas,available} \tag{8}$$

c. Since a non-negative quantity of lift gas is allocated to each well,

$$w_{gc} \ge 0 \tag{9}$$

$$K_{gs} g \sqrt{\rho_{G,in}} \max(P_{GS} - P_{AT}, 0) \geq 0 \quad (10)$$

$$g > 0 \; (if \; P_{GS} - P_{AT} > 0) \quad (11)$$

d. In keeping with a long term strategy for depleting oil and gas reservoirs (defined at a much higher level of decision making), there could be constraints on maximum allowable production from a particular well at any time. If this production is termed $w_{po,MAX}$ for the well, then the constraint becomes:

$$w_{po} \leq w_{po,MAX} \quad (12)$$

e. Usually, the oil and gas being produced from the well is accompanied by sand. The presence of sand is detrimental to the system in multiple ways, ranging from reduced production to severe damage to equipment, and hence the fraction of extracted sand must not exceed a certain value. One traditional way to ensure this is by limiting the production choke opening value to a certain maximum value u_{max}. However, to ensure a non-zero production, the choke opening must be a positive (non-zero) value. From an operational standpoint, u_{min} is generally not zero (although it may have to shut for strategic reasons). Aamo *et al.*,(2004) also assume a lower limit to the choke opening. Hence, our constraint on the production choke becomes

$$0 < u_{min} \leq u \leq u_{max} < 1 \quad (13)$$

f. To ensure that the well operates in a stable regime, we need a constraint on the instability in the well that we may tolerate. To achieve this formulation, we need an index that can quantify the instability. We discuss this in the next sub-section.

2.3 Characterizing the Instability

The instability is characterized by severe oscillations in production, implying deviations from the mean production over a given horizon. We consider the mean squared error of oil-production values as a suitable index. We ignore the transient phases such as well start-up while calculating this index. The index is calculated as:

$$I = \frac{1}{n}\sum_{j=1}^{n}(w_{j,po} - \overline{w_{po}})^2 \quad (14)$$

where, $w_{j,po}$ is the production at the j^{th} instant, $\overline{w_{po}}$ is the production over the time horizon for which this index is defined, and *n* is the number of data points for the production rates. Typically, the time period of the oscillations ranges from ~1 hour to ~3 hours. Hence, the time span for the horizon can be chosen to be of 1 day for the calculation of the index *I*. Preliminary results of calculating the index by running simulations on the well model (proposed by Jahanshahi *et al.*, (2012)) are as indicated in Table 1. In this work, the initial transient state of the well was neglected by beginning the calculation from the instant three hours after start-up. The instability index *I* is seen to be 2-3 orders of magnitude lower in the case of stable operation of the well, as compared to its values in the unstable regime. A 3 dimensional plot depicting the values of the index over a range of production choke opening values and gas injection valve opening values for the same set of simulations is also shown in Figure 4. This figure highlights the stable and unstable regimes based on the instability index. A suitable tolerance value for the index I_{tol} can be chosen to reflect the constraint on the casing heading instability and can be written as:

$$I \leq I_{tol} \quad (15)$$

A discussion of the implementation of the formulation along with results has been presented in Mukhtyar, (2013).

Table 1: Instability Index *I* values for different gas and production choke opening pairs

g \ u	0.1	0.5	1
0.1	8.61	21.58	32.36
0.5	0.03	58.12	83.28
1	0.01	0.03	0.03

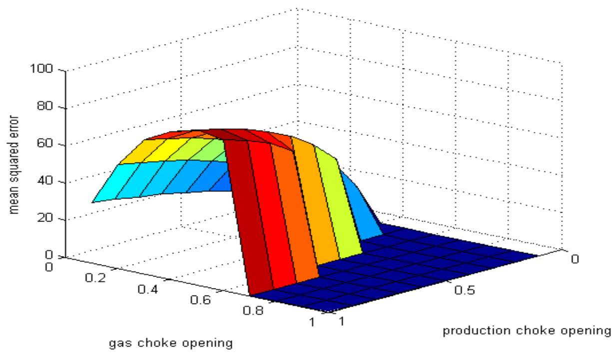

Figure 4: Index of stability vs. both choke openings

3. ESTIMATING THE DOWNHOLE PRESSURE

As mentioned earlier, regulating the well production rates to be stable at optimal values requires a fairly accurate characterization of the pressure profiles including the downhole flowing pressure. In the presence of significant noise and the harsh environment in the subsurface, an accurate sensing of the pressures is usually difficult. Earlier research efforts in this direction to estimate the downhole flowing pressure (Aamo *et al.*, (2004), Eikrem *et al.*, (2004), and Scibilia *et al.*, (2008)) have focused on the use of state estimation approaches which are model based and need a fairly accurate model to represent the relationships. Here, we explore an alternate approach that relies on the use of statistical data based estimation schemes. Given that the measurements would be both noisy and strongly correlated, we propose to use an approach based on the multivariate PLS algorithm suitably formulated in an errors-in-variables (EIV) framework (Vijaysai *et al.* (2005)).

In a typical well environment, the well head pressure values such as the tubing head and casing head pressures are reliably measured using pressure gages. There could be additional measurements from pressure gages at the lift-gas injection point (inside the tubing). Given that these could be strongly correlated with the bottom hole flowing pressure and also amongst themselves, we propose the development of a data-based soft sensor to estimate the bottom hole flowing pressure $\widehat{P_{DH}}$, as per the schematic diagram in Figure 5:

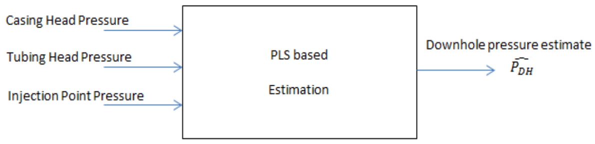

Figure 5: Schematic representation of estimator for $\widehat{P_{DH}}$

Let X be the regressor block containing noisy time samples of the pressure values at the well casing head, tubing head and the lift gas injection point. Further, let Y be the vector of noisy measurements of the bottom hole flowing pressures. The EIV based formulation of the PLS algorithm first constructs an augmented matrix Z = [Y X], and performs a singular value analysis of this block to estimate the noise variances in the presence of collinearity in the X block. These noise variance estimates are used in a subsequent data cleansing step to generate a clean matrix of measurements Z_c = [Y_c X_c]. The PLS based regression coefficients are then directly estimated from this matrix Z_c using the generalized principal components algorithm. For brevity, we have not included the individual steps associated with the EIV based formulation but would refer the reader to the original publication by Vijaysai *et al.* (2005) for further details. Since pressure transients are relatively on much shorter time scales even in the presence of instabilities in the well, we use the same static version of the EIV-PLS and evaluate its performance during transient behaviour in the well.

4. RESULTS

In this section, we present validation results using the proposed optimization formulation as described in Section 2. We also evaluate the EIV-PLS based soft sensor for generating robust estimates of the downhole pressure. For simulation purpose, we use the model proposed in Jahanshahi *et al.*, (2012), and impose additional constraints relating to gas availability and production from the well. For the purpose of soft sensor evaluation, we consider that pressure measurements are corrupted to the extent of ±5% for the downhole pressure and ±2% for the pressures in the X block.

4.1 Soft sensor for downhole pressure

A total of 5050 samples comprising both stable and unstable region of operation were considered for soft sensor evaluation. Of these, 2525 samples were used as training data and 2525 were used for validation. It was observed that 2 latent variables used up 93.2% of the variance in X to explain 99.8% of the variance in the Y block. Figures 6 and 7 show the cross validation results for the prediction of the downhole pressure during steady as well as unstable production, respectively. It can be seen from the figures that the PLS based soft sensor generates reliable estimates of the downhole pressure even in the presence of noise in both the X and the Y block.

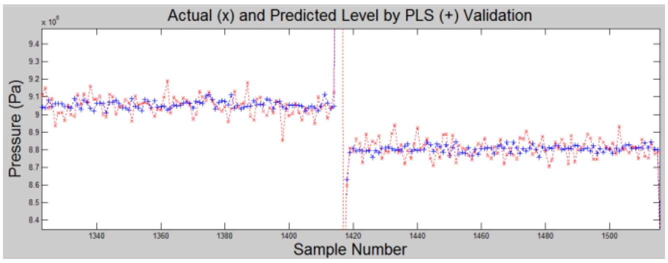

Figure 6: PLS Estimates of downhole pressure in the stable regime; MSE (divided by mean pressure value) = 0.005

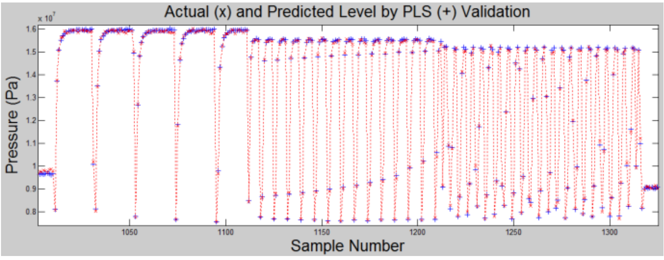

Figure 7: PLS Estimates of downhole pressure in the unstable regime; MSE (divided by mean pressure value) = 0.06

4.2 Case study on optimization formulation

We discuss the case study of a single well utilizing the optimization formulation proposed in Section 2 with constraints. Additional constraints that we impose are:

The constraint on maximum production from the well is:

$$w_{po} \leq 15 \text{ kg/s} \tag{16}$$

Further, the sand production could restrict the production choke opening to be less than 80% of its maximum value, while the constraint on the minimum valve opening is 20%.

$$0.2 \leq u \leq 0.8 \tag{17}$$

To reflect compressor power constraints and/or limited compressed lift gas availability, we impose the additional constraint on the gas injection flow rate as

$$w_{gc} \leq 1 \text{ kg/s} \tag{18}$$

The upper limit on Instability Index (I) for stable production:

$$I \leq 0.2 \tag{19}$$

Table 2 shows the results of the optimization. The stable optimal production of 14.76 kg/s is realised at a value of production choke opening u = 0.36, and gas choke opening g = 0.5. A gas injection flow rate 0.98 kg/s satisfying the constraint on gas availability resulted from the optimization. It is important to note that if the production choke was open at a relatively higher value of 0.38, the well behaviour would have transitioned into an unstable mode, resulting in reduced average production of 9.78 kg/s.

Table 2: Oil production flow rates (kg/s) near optimum

g\u	0.34	0.36	0.38
0.48	9.39	9.25	9.20
0.5	14.54	**14.76**	9.78
0.52	14.66	14.89	15.09

Table 3 shows that the gas injection flow rate is within the specified limit of 1 kg/s. Table 4 shows that the instability index is well within the specified threshold of 0.2.

Table 3: Gas injection flow rates (kg/s) near optimum

g\u	0.34	0.36	0.38
0.48	0.77	0.77	0.77
0.5	0.97	**0.98**	0.81
0.52	1.01	1.02	1.02

Table 4: Index values near optimum

g\u	0.34	0.36	0.38
0.48	41.23	43.95	46.63
0.50	0.10	**0.11**	44.4
0.52	0.09	0.10	0.10

We further examined the effect of relaxing the constraint on gas availability from a value of 1 kg/s to 0.8 kg/s. It was observed that stable optimal production of 9.12 kg/s was realised at a changed production choke opening of 0.12 and a gas flow rate of 0.79 kg/s. The advantage of using the additional degree of freedom can be seen in Table 5. For the same flow rate of gas (italicized in the table), the choke opening corresponding to greater oil production was chosen (written in brackets below the gas flow rate readings).

Table 5: Gas injection flow rates (kg/s) near optimum

g\u	0.1	0.11	0.12
0.1	0.75	0.77	*0.79* $(w_{po} = 9.12\ kg/s)$
0.11	0.76	0.79	0.81
0.12	0.78	0.80	0.82
0.13	*0.79* $(w_{po} = 8.16\ kg/s)$	0.81	0.83

This exercise highlights the importance of considering both gas valve opening and production choke opening as degrees of freedom to maximize and stabilize oil production.

5. CONCLUSIONS

In this paper we proposed an alternate optimization formulation that integrated the problem of lift gas allocation and elimination of casing heading instability under more realistic constraints to achieve stable and optimal production from a well. We also proposed an index to quantify the casing heading instability of a well which was included as a constraint in the optimization formulation. Simulation results using this formulation on a single well showed that a coordinated manipulation of the production choke and the gas injection valve is necessary in the presence of constraints to achieve stable and optimal production. We further showed that the difficulty of lacking accurate measurements of downhole pressure for the purpose of feedback control can be alleviated through the use of EIV-PLS based statistical estimators. Further studies on integrating this optimization approach with the lower level closed loop control problem layer and its extension to the multiple wells case (including modeling the pressure distributions in the manifold, where the confluence of oil production from different wells occurs) would be undertaken subsequently as part of this research.

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