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STABILIZATION OF GAS LIFTED WELLS

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Abstract: Oil wells with an oscillating production rate have a lower production compared to oil wells producing at a constant rate. This study looks at instability caused by the casing-heading phenomenon. Control is applied to achieve stable production rate. Two realistic gas lifted systems for oil and gas production are investigated, using the multiphase flow simulator OLGA2000. Different control structures are evaluated, and linear stability analysis is used to substantiate open loop simulation results. The study shows that substantial production improvement can be achieved by applying control to the above mentioned system. *Copyright ©2002 IFAC*

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1. INTRODUCTION

Hydrocarbons are produced from wells that penetrate geological formations rich on oil and gas. The wells are perforated in the oil and gas bearing zones. The hydrocarbons can flow to the surface provided the reservoir pressure is high enough to overcome the back pressure from the flowing fluid column in the well and the surface facilities. Detailed information on wells and well completion can be found in Golan and Whitson (1991).

Gas lift is a technology to produce oil and gas from wells with low reservoir pressure by reducing the hydrostatic pressure in the tubing. Gas is injected into the tubing close to the bottom of the well and mixes with the fluid from the reservoir, see Figure 2. The gas lifts oil out of the tubing and reduces the density of the fluid in the tubing. The lift gas is routed from the surface and into the annular conduit (annulus) between the casing and the tubing. The gas enters the tubing through a valve, an injection orifice, at the wellbore.

Gas lift can result in highly oscillating well flow when the pressure drop in the tubing is gravity dominated and there is a large annulus volume filled with compressible gas. In this case the pressure buildup inside the tubing under no-flow or low-flow conditions is faster than the pressure buildup in the annulus. If the pressure in the annulus is able to overcome the pressure in the tubing at a later point, the gas will flow into the tubing and the oil and gas will be lifted out of the tubing. After the fluid is removed from the tubing a new pressure buildup period starts. This type of oscillations is described as casing-heading instability and is shown in the first part of Figure 3. More information can be found in Xu and Golan (1989).

Figure 1 shows an example of a gas lift production curve. The produced oil and gas rates, assuming stable flow conditions, is a function of gas injected into the well at steady state. The curve also shows in which areas the well exhibits stable and highly oscillating flow, respectively. The region of optimum lift gas utilization may lie in the unstable region. Figure 1 is not valid for zero gas injection.

A requirement for casing-heading instability is pressure communication between the tubing and the casing, i.e. the pressure in both the tubing and the casing will influence the flow rate through the injection orifice. There are in principle three ways to eliminate highly oscillating well flow. First,

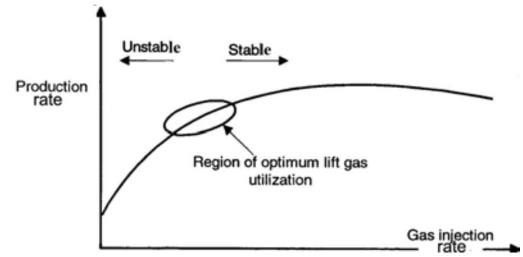

Fig. 1. The gaslift curve with the region of optimum lift gas utilization.

operating conditions can change to achieve stable condition. This can be done by increasing the gas flow rate and/or by reducing the opening of the production choke downstream the well. Both remedies reduces well efficiency. Second, the injection orifice may be a valve with critical flow, meaning that the flow through the injection orifice is constant. This is a solution that has achieved industrial interest. Third, the use of control is a method to stabilize well flow. This is the scope of the present study.

Large oscillations in the flow rate causes poor oil/water separation downstream, limits the production capacity and causes flaring. Hence, a reduction of the oscillations will result in increased processing capacity because of the reduced need for buffer capacity in the process equipment.

Control has to a limited degree been studied for single well systems. Some earlier work has been reported, (Jansen *et al.*, 1999) and (Kinderen, 1998). This earlier work looked only at single well systems, while this study also considers a realistic two-well system where one gas source supplies two gas lifted wells.

We will use the transient multiphase flow simulator OLGA®2000 (Scandpower, 2000), commonly used in the petroleum industry. This simulator has been used to study a set of realistic wells. The controllers are implemented in Matlab (The MathWorks, 2000).

A detailed well system model is prepared in OLGA. It includes the geometry of the well system, initial conditions and boundary conditions. OLGA is based on a modified two-fluid two-phase flow model. It uses semi-implicit time integration, which allow relatively long time steps. OLGA contains specific parametrized models for the production chokes.

The scope of the paper is to develop and assess a control strategy for the above problem and investigate alternative solutions depending on the availability of downhole online measurements. We believe that the paper introduces a new field for process control technology with a substantial potential.

2. SYSTEM DESCRIPTION

2.1 *Single well system*

The basis for this study is a realistic gas lifted well model, see well 1 in Figure 2. The parameters of this vertical well are given as:

- Well parameters:
  - · 2048 m vertical well
  - · 5 inch tubing
  - · 2.75 inch production choke
  - · 0.5 inch injection orifice
- Reservoir parameters
  - · P_R = 160 bara
  - · T_R = 108 ^{o}C
  - · PI = 2.47E-6 kg/s/Pa
- Separator inlet pressure
  - · 15 bara
- Gas injection into annulus
  - · 0.6 kg/s
  - · 120 bara
  - · 60 ^{o}C

The productivity index, PI, is defined by:

$$PI = \frac{\dot{m}}{\Delta P} \tag{1}$$

Where $\dot{m}$ is the total mass flow rate from the reservoir to the well and ΔP is the pressure difference between the reservoir and the well. This index relates the mass flow from the reservoir and into the well to the corresponding pressure drop. The PI is assumed constant.

We assume that there is no water in the produced fluids, only oil and gas. The gas/oil ratio, GOR, is 80 Sm^3/Sm^3. GOR is defined by:

$$GOR = \frac{\dot{q}_{gas}}{\dot{q}_{oil}} \tag{2}$$

Hence the gas-oil-ratio, GOR, is defined as the ratio between the volumetric gas rate and the volumetric oil rate at standard temperature and pressure.

2.2 *Two well system*

This study advances compared to earlier studies by focusing on a two well system with a common gas supply source. The two-well system in this study is shown in Figure 2. Well 1 is defined above, and well 2 is identical to well 1 except that it has a higher productivity index, PI = 3.00E-6 kg/s/Pa. The two wells produce the same reservoir fluid and connect to the same downstream separator. It is assumed that the separator is located close to the wellheads.

The two wells share the same gas source. The total gas injection rate is 1.1 kg/s. This study reflects the case when there is a shortage of gas supply for gas lift operation.

Since there is a limited gas supply, the question becomes how to use this limited lift gas to maximize the oil production. Oil has a much higher

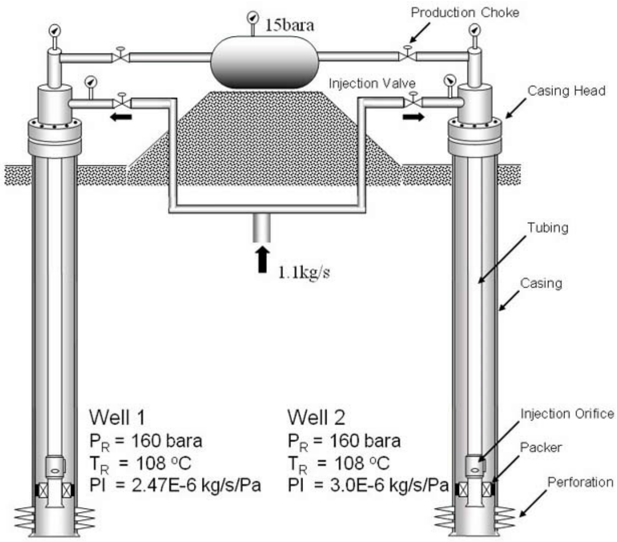

Fig. 2. Two-well system with common gas supply source.

sales value compared to gas, hence maximizing oil production is the vital point. Steady state analysis of the system (i.e. optimization on a static model) shows that the total oil production is maximized if the gas injection rate equals 0.5 kg/s to well 1 and 0.6 kg/s to well 2.

2.3 *OLGA and Matlab*

For this study the multiphase flow simulator OLGA is used for the well and gas supply simulations, while Matlab is used for controller development and implementation. Matlab will read the process outputs from OLGA, calculate new process inputs and return them to OLGA. The connection between OLGA and Matlab is managed by the OSI (OLGA Server Interface) toolbox for Matlab (ABB, 1998).

3. CONTROL OF SINGLE WELL SYSTEM

The measurements which are assumed available in this study are pressure at the wellhead, downhole and at the casing head, and mass flow through the production chokes and the injection chokes. The pressure measurement downhole is often not reliable and hence it can be disadvantageous to make the control structure dependent on this measurement.

The process inputs which can be used to control the one-well system are the production choke and the injection choke. The single well system is defined by well 1, with a gas lift supply rate of 0.6 kg/s.

3.1 *Control structure*

Two available control structures are studied. The first structure controls the downhole pressure, using the production choke. This control structure is the same as for well 1 in Figure 6. The second structure controls the pressure in the annulus, this control structure is the same as for well 1 in Figure 7. A PI-controller is used in both cases to control the pressure. The controllers are tuned using a combination of process knowledge and iterative simulations. The valve models include saturation and limitations on the valve opening/closing rate. The sampling time for the controller is 30 seconds.

3.2 *Simulation results*

The results from the simulations of the one-well system are given in Figure 3. These simulations are noise free. The system was run in open loop for about 4 hours before the controller was activated. The valve opening of the production choke in this period was 80 %. The simulation study shows that control stabilizes the system and increases the amount of produced oil by 10-15%. The valve settles at 55 % at the end of this simulation.

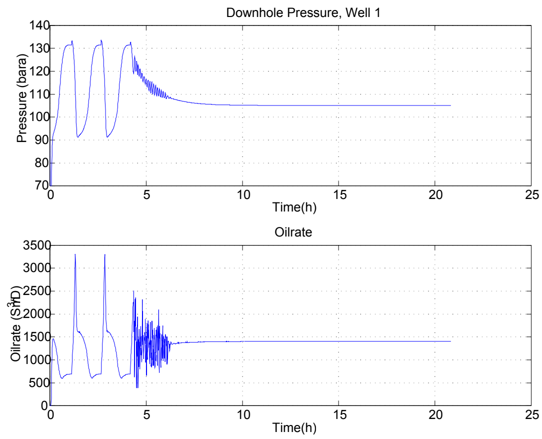

Fig. 3. Simulation results of single well system using pressure in annulus as controlled variable.

The oscillations during the open loop part of the simulations result from the casing-heading instability.

3.3 *Stability analysis*

As mentioned earlier an oscillating well can be stabilized by reducing the opening of the production choke. With low opening of the choke the pressure drop of the flow is dominated by friction. The fluid flow of well 1 in Figure 2 is stable at a high downhole pressure, for instance 122 bara, which corresponds to an opening of the production choke of 16 %. This means that it is no prerequisite to use control, because the low valve opening makes it possible to run the system in an open loop stable condition. This observation is supported by linear stability analysis. The Nyquist plot of the loop transfer function in Figure 4 is computed on the basis of the downhole pressure mentioned above (122 bara). The system is stable in closed loop, which is showed by the Nyquist curve, the curve is not encircling the critical point (-1,0).

At high openings of the production choke the system becomes unstable. This is seen in Figure

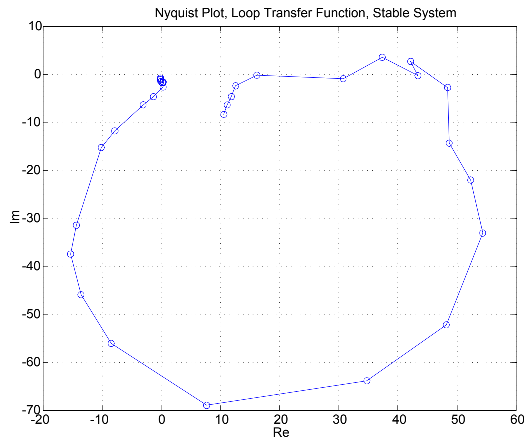

Fig. 4. Nyquist plot of loop transfer function for a stable system. The downhole pressure is 122 bara and the production choke opening is 16 %.

3 where the valve opening is 80 % in open loop. The pressure drop in the flow is now not friction dominated, but gravity dominated. This unstable behavior can also be seen from the Nyquist plot in Figure 5, here is the downhole pressure 105 bara and the production choke is 55 % open. The curve will encircle the critical point (-1,0) twice if the frequency runs from -∞ to ∞. This indicates that the open loop system has two poles in the right half plane.

The Nyquist plots have been generated from simulations of the closed loop well system. The reason why the identification has to be run in closed loop is that the well system is unstable for high choke openings. The setpoint for the closed loop system is a sinusoidal signal, and simulations with different frequencies for this sinusoidal signal have been run.

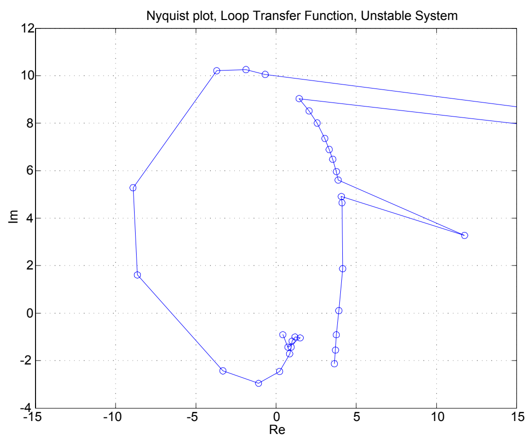

Fig. 5. Nyquist plot of loop transfer function for an unstable system. The downhole pressure is 105 bara and the production choke opening is 55 %.

4. CONTROL OF TWO-WELL SYSTEM

The oil flow rate from the two wells should be maximized, and at the same time be stable to prevent downstream handling problems. A means to achieve this is to keep the downhole pressure constant at the lowest possible level. This will result in stable inflow of gas from the annulus and high inflow of oil from the reservoir.

4.1 *Control of downhole pressure by choking production*

To be able to use the above mentioned production strategy the pressure in the well has to be controlled and the lift gas distributed with an optimal ratio between the two wells. To achieve these optimal gas rates it is necessary to include a control structure on the distribution system of the gas. The control structure in Figure 6 is proposed to achieve this.

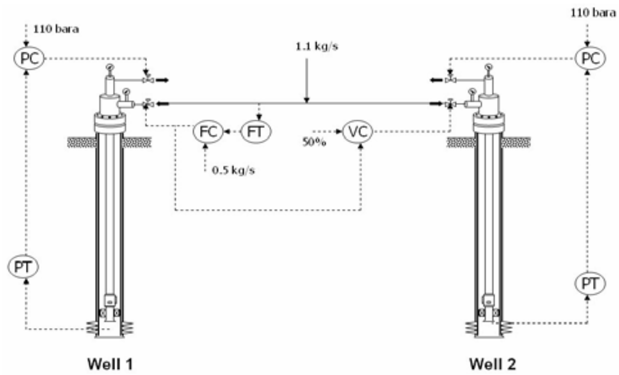

Fig. 6. Control stucture for stabilizing downhole pressure with use of production chokes.

This control structure focuses on controlling the downhole pressure. The pressure transmitters are located downhole in the wells. A stable pressure at this location is a requirement for a constant inflow of hydrocarbons from the reservoir to the well.

The downhole pressure is influenced by changes in the opening of the production choke. An opening of the valve results in a reduced pressure drop over the valve and this gives a reduced back pressure for the well. The well is hence able to increase its production. With a reduction in the opening of the production choke, the pressure drop over the valve is increased. This results in a lower mass flow from the well because of higher back pressure.

Since the supply of gas is constant at 1.1 kg/s, it is sufficient to control the gas flow rate to one of the wells. The mass flow rate to well 1 is controlled with the use of one PID-controller. To avoid saturation of injection choke 1, a controller is connected to injection choke 2. This valve is connected to a PD controller and is adjusted until the opening of injection choke 1 is about 50%. This second control loop is significantly slower than the flow rate control loop. This is a variant of a parallel control structure as found in e.g. Balchen and Mummé (1988).

4.2 *Control of pressure in annulus by choking production*

The advantage of using the pressure in the top of the annulus is the easier access to measurements.

Downhole pressure measurements are more rare and generally not regarded reliable by the industry. The proposed control structure for this setup is given in Figure 7.

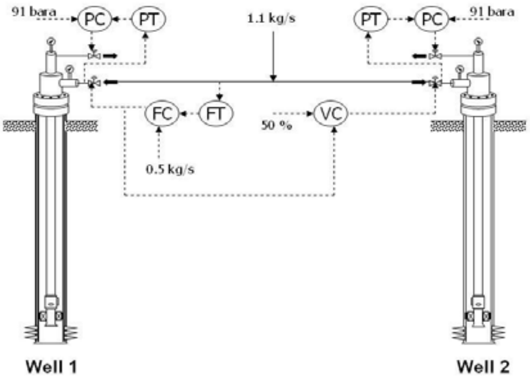

Fig. 7. Control of pressure in annulus with use of production chokes.

This control structure controls the two-well system by measuring the pressure at the top of the annulus. When the rates of injection gas to each well is constant, a constant pressure in the top of the annulus means a constant mass flow of gas from the annulus into the tubing. Since it can be argued that the instability is caused by compressibility of the gas in the annulus, the idea is that controlling the pressure in the annulus will stabilize the system.

4.3 *Controller development*

To control the two-well system, it was decided to use conventional PI controllers to control the downhole pressure and the pressure in the annulus. The controllers have been tuned in an iterative way, and the valve models includes saturation and limitations on the valve opening/closing rate. The sampling time for the controllers is 30 seconds.

4.4 *Simulations and measurements*

The simulations run in open loop for 4 hours before the loop is closed. The initial values equal steady-state conditions.

4.5 *Results from control of downhole pressure*

The results from the simulations with the control structure in Figure 6 are given in Figure 8.

The results from the open-loop simulations show that the downhole pressure in well 1 is stabilized at 96 bara while well 2 is stabilized at 132 bara. This is because all the injection gas is routed to well 1. The gas flows to the well with the lowest counter pressure, which is well 1, because this well has the lowest productivity index, PI. The productivity index is the only difference between the two wells. The well with the highest PI therefore gets the highest liquid level in the tubing and thereby the highest hydrostatic pressure. Well 2 produces at a low rate because of lack of lift gas, while

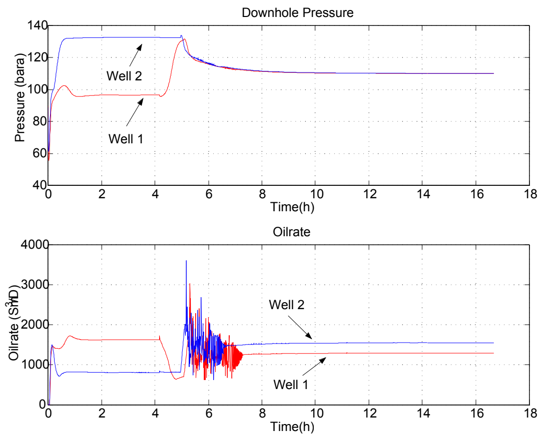

Fig. 8. Simulation results from control of downhole pressure in well.

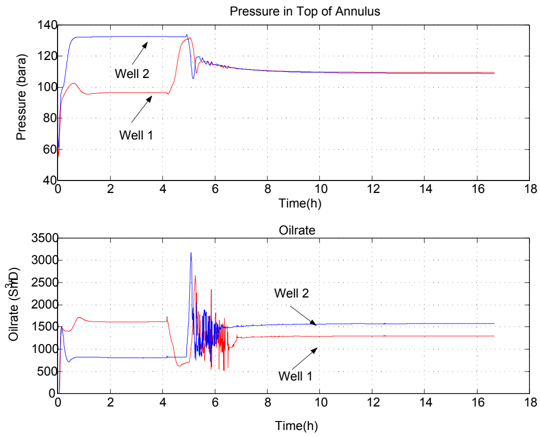

Fig. 9. Simulation results from control of pressure in top of annulus.

well 1 produces at a high rate because of the low downhole pressure. This shows the need for a control structure for the allocation of injection gas. Note that the gas lift flow rate to well 1 is 1.1 kg/s in open-loop, as opposed to 0.6 kg/s in section 3. This is why well 1 exhibits stable flow condition in open-loop; the pressure drop becomes friction dominant.

After the control loops have been closed, it takes almost 2 hours before the system is stabilized at the desired setpoints. This is roughly the time it is takes to build up the pressure in the annulus. There is a significant increase in production of oil from the two wells when the injection of gas is allocated between the two wells in an optimal ratio. The production is increased by 20%, see Figure 8. The choke openings at the end of the simulation are 40 % for well 1 and 60 % for well 2.

4.6 *Results from control of pressure in annulus*

The results from the simulations using the pressure in the annulus as the controlled variable, see Figure 7, show that this control structure also is able to stabilize the two-well system, see Figure 9.

5. DISCUSSION

A high rate of injection gas will stabilize the well, as seen in the simulations, but not at an optimal operating point. A fixed choke opening will also stabilize the well, provided the opening of the choke is reduced until the flow from the well is stable. The reason why an increased amount of lift gas and/or a reduced choke opening gives stable flow is that the flow in the tubing changes from gravitational dominant to friction dominant flow. An improved solution is to stabilize the well system in the unstable region with feedback control.

The reason why the system behaves differently in open loop for the one-well gas lifted system and the two-well gas lifted system, is the rate of the injected lift gas. The one-well system has a lift gas rate (0.6 kg/s) which results in an oscillating system because the pressure drop is gravity dominant, while the two-well system is stable because one well receives all the lift gas (1.1 kg/s) and thereby the pressure drop of the flow becomes friction dominant. The other well is stable due to the complete lack of lift gas.

The control structure which is applied to the distribution system for the lift gas between the wells in the two-well system can be seen as decoupling the two wells. This means that the operation of one well will not affect the other, they act as independent systems. The control structure for allocation of lift gas is required for the two-well system to be able to reach its setpoints. If all lift gas is going to one well, control of the pressure alone will not be able to redistribute the lift gas.

This study describes two possible control structures for stabilizing the two-well system. Both these structures have advantages and disadvantages. The structure which uses measurements of the pressure downhole has a shorter dynamic lag between the control input and output, compared to the measurement in the top of the annulus. However, the pressure measurement downhole in the well is not always reliable, because of the harsh conditions in a well. The second control structure used the pressure in the top of the annulus as measurement, this measurement is easy available and reliable.

The difference between the two control structures regarding stabilization of the well systems is small. The reason is that the pressure waves move so quickly that the dynamic lag through the casing is small for this type of system.

To elaborate on the controller tuning, this was done iteratively based upon process understanding. The setpoints for the two wells were reduced as much as possible, while maintaining a reasonable operating range for the production chokes, 40-60% opening. A high choke opening implies loss of controllability, since changes in the opening in the area 70-100% hardly affect the pressure drop across the valve. It shall be notified that it was not necessary to resort to nonlinear control, for instance gain scheduling. Linear controllers could handle the operating range in question.

6. CONCLUSION

This paper shows how control can improve the performance of gas lifted wells by stabilizing the well flow. Different control structures are available for this well stabilization. Finally, the study substantiates that there is a substantial economical benefit from controlling the pressure in the well, and thereby stabilizing production.

7. ACKNOWLEDGEMENT

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