Emulation and Control of Slugging Flows in a Gas-Lifted Offshore Oil Production Well Through a Lab-sized Facility

Kasper Jepsen¹, Leif Hansen¹, Christian Mai¹ and Zhenyu Yang¹

Abstract—In the oil and gas industry, the gas-lift assist approach is often used in the production wells when the reservoir pressure is insufficient to ensure cost-effective production. However the side-effect of this approach is the often occurrence of regular/irregular large oscillations of the production flow and pressures in the production well system, which is referred to as the slugging flow problem. This instability is mainly due to the casing-heading mechanism. This work investigates the possibility to use a feedback control for stabilizing the production operation without sacrificing the production capability. A lab-sized production well system is constructed in an economic manner. Afterwards, a simple nonlinear model is derived according to physical principles and then verified with the experimental facility. A observer-based state feedback control is designed to handle the potential slugging problem. The developed controller manipulates the openness degree of the production choke based on feedback a number of pressure measurements. The current simulation results showed satisfactory control performances by stabilizing the system operation at some relatively large production rate which is originally open-loop unstable.

1. INTRODUCTION

In the oil & gas production, an approach known as gas lift production well is often employed in order to cope with a low reservoir pressure. By following the gas-lift methods, an amount of gas is continuously injected into the reservoir or well to increase the reservoir pressure or lower the density of fluid inside the well, so as to keep a productive flow rate through the production system. The lift-gas normally consists of natural gas produced from the reservoirs themselves, and then it is pumped back down into the reservoir or well though the casing of the well, also known as the annulus, as illustrated in Fig.1.

The gas-lift approaches can maintain a reasonable production rate, however, some instability can be also easily caused due to the gas injection mechanism [2], [4]. This instability is reflected by largely and regularly oscillated pressure and flow measurements under static operating conditions. This unstable flow phenomenon is usually referred to as the slugging flow problem in the multiple phase flow dynamics [9]. This is also known as casing-heading instability problem in the oil & gas production processes [4], [6]. This problem is mainly due to the cyclic behavior of two sequential phases, as illustrated in Fig.2, i.e.,

- **Annulus build up phase**: As shown in Fig.1. When the pressure inside the annulus is lower then the pressure

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inside the tubing at the injection valve position, no gas will flow into the tubing, and the pressure inside the annulus will build up, until the pressure in the annulus becomes greater then the pressure inside the tubing, then the next phase starts.

- **Annulus blowout phase:** When the pressure of the annulus is greater than that inside the tubing, the gas starts to flow into the tubing. Due to the fact that the gas is less dense than oil, the density of the mixture in the vertical tubing becomes smaller as more gas squeezes into the tubing, and thereby the hydrostatic pressure inside the tubing is reduced. The pressure inside the annulus will also drop as the gas flows into the tubing. In most observed conditions the pressure inside the tubing increases faster than the pressure does in the annulus. Thereby at some point the gas from the annulus will stop flowing into the tubing, and the next phase starts again.

It has been discovered that casing-heading instability is not the only source of unstable well production, but it has been observed that it is the most significant factor for gas-lifted oil-wells [2], [10], some investigation about the gas-lift instability can be found in [3], [4], [5] and references therein, and the control of this instability can be found in [6], [7], [10]. In many practical situations at offshore platforms, the slugging problem is to handled in a manual control manner, which is definitely not cost-effective nor highly reliable.

This paper will investigate an automatic anti-slugging solution for unstable well production by using some advanced control mechanism, and some stable operation at a relatively large production rate (at least larger than the maximal production rate subject to a stable open-loop system) is expected by the end. The rest of the paper is organized in the following: Section II introduces the constructed lab facility, which is used to emulate a gas-lifted production well and serves for anti-slugging study; Section III illustrates the mathematical models for the considered system; Section IV discusses the anti-slugging control design and some simulation results; and finally we conclude in Section V.

II. LABORATORY FACILITY CONSTRUCTION

In the constructed lab facility, we use water to emulate crude oil flowing through the pipelines, and the air is used to emulate the lift gas. A schematic diagram of the entire system is illustrated in Fig.3.

A. Structure and components

In order to facilitate the emulation of a real-world well, the following main components are present.

1) **Production Well Emulation:** In the actual systems, the production well usually consists of a number of serially connected pipelines, and it can consist of both vertical and horizontal segments, both can be up to several kilometers in length. The layout depends heavily on the reservoir geometric configurations. In our lab facility, the production well tube is emulated by a three-meter-long PVC pipeline held vertical, connected with a horizontal PVC pipeline line through a turn junction. The horizontal pipeline is connected with a pump system which supplies water. All the PVC pipelines are transparent so that the flow regimes and changes at different locations can be visually observed.

2) **Reservoir Emulation:** A variable speed pump system is used to emulate the pressurized reservoir, which is what the well endpoint (down-hole) is connected to. The pump is controlled to produce proper pressure (referred to as reservoir pressure) at the outlet of the pump system. There is also an manual valve downstream of the pump system, which is used to emulate the difference pressure between the reservoir and the down-hole pressure. The flow rate out of the pump system is measured by a flow-meter (FT1 in Fig. 3).

3) **Gas-Injection Emulation:** The annulus is emulated by a air buffer tank, annulus in Fig.3. The annulus is connected with the horizontal pipeline at the junction point through a manual ball valve, the gas injection valve. The air is supplied and compressed into the annulus by an external compressor. There are two modes to control the gas-inlet to the annulus: 1) Mass Flow Controller (as MFC shown in Fig. 3); 2) Proportional Control Valve (PCV). The MFC mode is realized by a commercial flow controller.

4) **Production choke:** The choke valve used in the setup is a 1.5 inch stainless steel ball valve, and an electric actuator of the type UNIC-05 is used to control the openness degree of the choke valve. In order to measure the openness degree of the valve, a potentiometer is mounted on the valve motor shaft.

B. Sensors and Measurements

A number of pressure sensors and flow-meters are employed in the constructed facility. They are listed in the following Table 1.

C. Available control mechanisms

There are a number of possibilities to control the entire system’s operation, such as:

- Control of the pump speed so as to emulate different reservoir pressure conditions;
### III. Mathematical Modeling

The modeling method proposed in [1] is adopted to model the considered system operation. According to the mass balance of gas and liquid in the system volumes, there is

\[
\begin{align*}
\dot{x}_1 &= w_{G,in} - w_{G,inj} \\
\dot{x}_2 &= w_{G,inj} + w_{G,res} - w_{G,out} \\
\dot{x}_3 &= w_{L,res} - w_{L,out}
\end{align*}
\]

(1) (2) (3)

Where \( x_1 \) represents the amount of gas (air) in the annulus in kg, \( x_2 \) represents the amount of gas in the tubing and \( x_3 \) represents the amount of liquid (water) in the tubing. The mass flow rates used in (3) are listed in table II. All other variables used in the modeling procedure are listed in table III, and table IV list all relevant coefficients for this developed lab system model.

### TABLE II

**Model mass flow rates (kg/s)**

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( w_{G,inj} )</td>
<td>Gas into the tubing</td>
</tr>
<tr>
<td>( w_{G,out} )</td>
<td>Gas out of the production choke</td>
</tr>
<tr>
<td>( w_{G,res} )</td>
<td>Gas from the reservoir</td>
</tr>
<tr>
<td>( w_{L,res} )</td>
<td>Liquid from the reservoir</td>
</tr>
<tr>
<td>( w_{L,out} )</td>
<td>Liquid out of the production choke</td>
</tr>
<tr>
<td>( w_{out} )</td>
<td>Total mass flow out of the production choke</td>
</tr>
<tr>
<td>( w_{res} )</td>
<td>Gas and liquid from the reservoir</td>
</tr>
<tr>
<td>( w_{G,in} )</td>
<td>Gas into the annulus</td>
</tr>
</tbody>
</table>

### TABLE III

**Model variables**

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( \rho_{G,ab} )</td>
<td>Gas at the bottom of the annulus</td>
</tr>
<tr>
<td>( \rho_{G,at} )</td>
<td>Gas at the top of the annulus</td>
</tr>
<tr>
<td>( \rho_{G,tt} )</td>
<td>Gas at the top of the tubing</td>
</tr>
<tr>
<td>( \rho_{mix} )</td>
<td>Mixture in the tubing</td>
</tr>
<tr>
<td>( \theta_c )</td>
<td>Mechanical angle of choke valve</td>
</tr>
</tbody>
</table>

**Control variables**

- \( u_1 \): Relative signal to choke valve in the interval: \([-1, 1]\]
- \( u_2 \): Relative set-point to the MFC in the interval: \([0, 1]\]

### TABLE IV

**Model constants**

<table>
<thead>
<tr>
<th>Name</th>
<th>Description</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>( w_{gas,\text{max}} )</td>
<td>Maximum mass gas flow</td>
<td>( 1.739 \times 10^{-4} )</td>
<td>kg/s</td>
</tr>
<tr>
<td>( P_{gs} )</td>
<td>Gas source pressure</td>
<td>( 2.17 \times 10^5 )</td>
<td>Pa</td>
</tr>
<tr>
<td>( P_0 )</td>
<td>Back pressure in the system</td>
<td>( 1 \times 10^5 )</td>
<td>Pa</td>
</tr>
<tr>
<td>( P_{res} )</td>
<td>Reservoir pressure</td>
<td>( 1.24 \times 10^5 )</td>
<td>Pa</td>
</tr>
</tbody>
</table>

For the lab setup, there is a difference in the annulus structure from the real well. Instead of using a the annulus surrounding the oil carrying pipe, like on a well, the lab-setup uses an air tank, and therefore the height difference between the air inlet and outlet is almost zero.
A. Production choke valve - $w_{out}$

Regarding the choke valve, some mechanical dynamics need to be taken into account [8], even though the very fast dynamics of the electric motor and gear acceleration can be ignored. The valve part can be described as

$$\theta_v(u_1) = \int w_{valve} \cdot u_1(t) \, dt + \theta_{v,0}$$

$$w_{out} = K_{pv}(\theta_v(u_1)) \cdot \sqrt{\max(P_{ut} - P_0, 0) \cdot \rho_{mix}}$$

B. Lift-gas flow rate $w_{G,in}$

Because gas flow rate into the annulus is controlled by the MFC, which is relatively fast compared to the rest of the system, there is only the static model is used:

$$w_{G,in} = w_{G,in,\max} \cdot u_2 \quad \text{if} \quad P_{gs} \geq P_{mfc,\min}$$

Where $P_{mfc,\min}$ is the gas supply pressure required for the MFC to function properly at all flow-rates and $w_{G,in,\max}$ is the maximum mass flow rate chosen.

C. Gas injection rate - $w_{G,inj}$

For the gas injection valve, when the orifice coefficient $K$ of this valve is estimated based on measured data [8], the gas injection rate can be estimated by

$$w_{G,inj} = K \cdot \sqrt{\max(P_{ab} - P_{tb}, 0) \cdot \rho_{G,ab}}$$

D. Reservoir-well flow rate - $w_{L,\text{res}}$

The liquid fed from the reservoir to the tubing is determined according to a virtual well-reservoir valve. In this case an actual valve is used (V4 shown in Fig. 3) and so we determine this virtual valve’s functionality according to the actual valve characteristics, i.e.,

$$w_{L,\text{res}} = \frac{K_{v,\text{res}} \sqrt{\max((P_{res} - P_{bh}) \cdot 10^{-3}, 0)}}{36}$$

E. System Block Diagram and Validation

The entire system model is illustrated by a block diagram as shown in Fig. 5. The developed model is also checked with the experimental tests. One comparison result is shown in Fig. 6. It is clear that the mathematical model shows a similar trend as the experiment, but that a frequency deviation can be clearly observed as well.

We suspect this is mainly due to the neglecting of the static and dynamic friction modelings in the current model as well as the hysteresis feature of the gas injection valve. More systematic investigation of this part is ongoing under the current stage. For more details, we refer to [8] regarding to this modeling part.

F. Stability Analysis and Bifurcation Maps

The stability of system at various choke valve operating points is also checked, i.e. whether the system is open-loop stable. The result of this validation is shown in fig. 7. Again it is clear that the lab and mathematical models show a similar trend, with some observable deviations. These deviations could also partially be due to the imprecise model issue, as we discussed in the above.
The pole placement method is used to derive the control parameters as well as the estimator parameters.

A. Linearization and estimator design

The model is linearized at an operating point where both measurements and simulations show to be unstable. The linearized model is then evaluated by performing a simulation, by which it is found that the linear model has sufficient performance.

From the linear model a linear state-space estimator (observer) is designed using pole placement, and the resulting estimates are shown in fig. 11. This shows that the estimator performs as required and tracks the actual state-variables from the nonlinear well. From this, it is possible to use the estimated states for feedback control.

B. Full-state feedback design

Due to the fact that the linearization is done at the metastable point the system is to be stabilized at, no tracking capability is needed, and full-state feedback without any reference is utilized.

The stability of the system is the primary objective, the reason for this being, that once the closed loop system is running and has stabilized, no inputs other than disturbances are to be expected.

The closed-loop poles are therefore picked based on the open-loop poles and minimizing the amount of control effort required. Thereby the poles final positions of the poles are \(-226.64, -0.12 \pm 0.73i\) and \(-30\).

C. Simulated controller results

To validate the functionality of the controller, a simulation is performed. The simulations are based on the nonlinear model. The initial states for the simulation are chosen to be close to, but not exactly at, the equilibrium point. The results of the simulation can be seen in fig. 12.

It can be seen from the figure, that the nonlinear model can be stabilized using the designed controller. Thereby the pressures in the system will not oscillate, and a stable pressure, leads to a stable flow, and a stable flow will result in improved conditions for downstream equipment.

If one were to change the initial states further, the controller is unable to stabilize the system (the nonlinear...
Fig. 12. Example of simulated stabilization of unstable operating point red without controller, and blue is with the designed controller model), which also means that the controller can’t stabilize the system if the oscillations are allowed to reach larger amplitudes.

The stabilization of the system, also seems to have increased the production. The gain in production can be seen from fig. 13, since we know that a lower tubing-bottom pressure, will result in more flow from the reservoir. It is clear that between the cases, the lowest pressure at the bottom of the tubing is made possible when the choke valve is open to $40^\circ$, and with a stabilizing controller running.

![Graph](image1)

Fig. 12. Example of simulated stabilization of unstable operating point red without controller, and blue is with the designed controller model.

Fig. 13. Example bifurcation map with stable and unstable operating points

V. CONCLUSION AND FUTURE WORK

A small scaled gas-lifted production well system model is constructed, and it emulate the realistic system in a quite reasonable manner.

The lab-setup is also providing a opportunity the observe the slugs while they are occurs. The lab-setup can be even be used for other applications, eg. riser based slugging.

A simple mathematical model is developed according to the physical principles, and this model is further validated through experimental tests. The comparison with experiments shows that the model could be further enriched if we intend to have good data matching instead of trend matching, for example, by adding the dead-zone model to the air injection valve, the mismatching illustrated in Fig. 4 can be significantly reduced. Even though the addition of this extra non-linearity into the current system model won’t improve the current control performance, which is developed based on the linearized model, the enriched model could serve as a more precise platform for some advanced control design, e.g., some direct nonlinear control solutions.

The controller made in this investigation works well is only working in simulation, and the implementation and experimental testing are under going.

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