Automatic Control of Unstable Gas Lifted Wells
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Abstract
Oil production wells on gas lift are sometimes unstable at low gas lift rates, even though steady-state flow analysis gives most efficient production at these gas lift rates. Unstable production, often called heading, may lead to periods of reduced or even no liquid production followed by large peaks of liquid and gas. This results in average oil production less than expected, and oil and gas production less than the systems design capacity to allow for the production peaks without causing shutdowns.

To solve the problem the amount of lift gas is normally increased beyond the most optimum rate. When the lift gas supply is limited, other gas lifted wells must then be shut in.

This paper describes one field proven sequence based automation for oil production, plus a new model-based automatic controller. Both technologies solve the problem of unstable production from gas lifted wells through manipulation of the production and/or the gas-injection chokes. The sequence-based automation and the model-based controller stabilize the production at operating points that would be unstable under standard operation. Field measurements such as wellhead pressure, annulus pressure etc. are inputs to the controllers (or are used by the controller).

Examples are given of the model-based controller working together with realistic transient flow models of gas lift wells. Testing of the model-based controller on real unstable wells is planned.

Introduction
In production systems with gas lifted and naturally flowing wells, the problem of lift-gas allocation is well known. Many companies still use the traditional gradient method in order to allocate the lift gas between wells optimally so that the total average oil production is optimized when the available amount of lift gas is limited. However, this approach has several disadvantages. First it does not account for the fact that the wellhead pressures and flow rates are mutually dependent due to the pressure drop in the gathering system. Secondly, and sometimes more important, it does not account for heading problems. Last but not least, the problem of proper and safe unloading is also not addressed. Thus, an automation system that handles oil production should take all these factors into account.

Currently, there is an increasing interest within the oil industry for addressing oil production optimization using control system technologies and optimization techniques. There are several reasons for this:
1. Reduced oil prize gives an increased focus on costs and production efficiency.
2. Many reservoirs are today depleting. This means that the total oil production is dependent of the well performance rather than capacity limitations of the processing plant.
3. Taxes and pressure on energy utilization has increased in a number of areas recently. For example, the Norwegian CO\textsubscript{2}-tax for the offshore industry is 50USD/metric ton CO\textsubscript{2} produced. This gives an enormous incentive to reduce energy consumption on the installations.

Looking at other industries, such as Ethylene cracking and polymerization, the possibility for increasing throughput through a systematic approach in order to avoid downtime, debottleneck the process and continuously monitor the performance is in these industries crucial to their profitability. It is obvious that the oil industry has much to learn regarding these matters.

Possible benefits by increasing the level of automation in the oil industry are:
1. Increased safety due to smooth behavior during continuous production and start up, and shut in of wells.
2. Increased production due to less downtime, faster startup and continuously optimized production.
3. More efficient use of manpower through simplification of the well handling, and stable behavior of the wells.
Statement of the problem

Typical gas lifted wells have a stable behavior at elevated gas injection rates and unstable behavior at low gas injection rates. This means that a gas lifted well is not producing the maximum possible amount of oil at low gas injection rates in spite of the fact that these wells are operated most efficiently at these injection rates. Unstable operational conditions are the most important reason for this.

Operating a gas lifted well under unstable conditions has several disadvantages. First, the full lift potential in the gas is not properly used, resulting in a very inefficient operation. Second, surges in the production facilities may be so huge that severe operational conditions are likely to occur. Third, production control and allocation becomes very difficult.

Stability Problems

Unstable operational conditions may occur in a gas lift well because the characteristics of the system are such that small perturbations can degenerate into huge oscillations in the flow parameters. Unstable production, often called heading, may lead to periods of reduced or even no liquid production. To understand why heading occurs consider Fig. 1 that illustrates the stability region for a typical lift gas performance curve. A similar curve was first presented in Ref. 1. A typical gas lifted well configuration is shown in Fig. 2.

At the highest gas injection rates, the pressure drop in the tubing is dominated by friction. If the GOR (Gas Oil Ratio) rises, the tubing pressure will increase which will reduce the gas injection rate. This region therefore ensures stable production and explains why well stabilization by increased gas injection can be successful.

At low gas injection rates however, the hydrostatic pressure gradient dominates the pressure drop in the tubing. A small increase in GOR results then in a lower tubing pressure, which leads to a higher gas injection rate from the annulus into the tubing through the down-hole gas lift valve. Since the gas rate is restricted by a gas injection choke at wellhead, the gas pressure in the annulus will be reduced. After a time the gas rate into the production tubing will therefor be reduced, with resulting lower oil production rates. At low gas injection rates the well is therefore intrinsically unstable in spite of the fact that wells are operated most efficiently on the upward slope of the LPR curve; cf. Ref. 1.

To further illustrate the stability problem, a stepwise description of a heading cycle is given below:

1. Starting with an annulus pressure down-hole that is lower than the bottom-hole pressure, there is no gas flow through the down-hole gas lift valve into the tubing. Production rate and gas/liquid ratio is low. Gas is injected through the gas injection choke and annulus pressure builds up.
2. After some time, the annulus pressure exceeds bottom-hole pressure, and gas is injected into the tubing through the down-hole gas lift valve.
3. The injected gas lightens the tubing gradient so that bottom-hole pressure begins to decrease. Simultaneously, the production rate and wellhead tubing pressure begin to increase.
4. Gas now flows from the annulus into the tubing at an increasing rate. Because insufficient gas can be supplied through the gas injection choke, annulus pressure decrease rapidly.
5. Oil and gas are produced through the production choke at a high rate. Wellhead tubing pressure passes through a maximum and bottom-hole pressure passes through a minimum.
6. With decreasing annulus pressure, gas flow through down-hole gas-lift valve decreases. The gradient in the tubing becomes heavier and bottom-hole pressure increases. The production rate and wellhead tubing pressure decreases again.
7. When bottom-hole pressure exceeds annulus pressure, gas injection into the tubing stops. With continued gas injection rate at the wellhead, annulus pressure starts to build again.

Typical unstable gas lift well production is shown in Fig. 3 and Fig. 4 for a typical North Sea well at two different gas injection rates. The simulations were generated using the dynamic multi-phase flow simulator OLGA (see e.g. Ref. 2), which also was used to calculate the resulting lift performance relationship curves shown in Fig. 5. Here the average oil production rates are shown for different gas lift rates. As seen, the loss in average production is high for unstable production.

Unstable production of gas lifted wells cause many drawbacks, surge is not in agreement with smooth operation and it implies safety aspects and shutdown risks. The total oil and gas production must usually be less than the systems design capacity to allow for the peak production. Unstable mode often decreases sharply the lift gas efficiency. In addition, difficulties with gas lift allocation computation due to instabilities are also common. Well instabilities also induce other drawbacks on facilities and well operations on equipment.

Since heading can be caused by a large variety of factors, such as incorrect gas lift string design, improper valve setting, wrongly sized injection valve port, variation in supply pressure, or valve leaking or plugging, it is often difficult to find the origin of the heading. As a result, a pragmatic approach is often used to solve the problem in short term. For example, if a well is heading the operator often increases the amount of lift gas or increases the back-pressure by adjusting the wellhead production choke to a smaller opening (choking). Although these methods can be effective in reducing heading, production is still sub-optimal as either too much lift gas is used (high cost and limited availability of lift gas) or the well is produced against a high back-pressure (at low rate). In most cases, too much gas is injected into the gas lifted wells or the production rate is not maximized.
Reducing the size of the down-hole gas lift valve orifice may also reduce or solve the heading problem, but the resulting higher annulus pressure and gas injection pressure lead to higher costs.

**Proven technology**
In 1990 Elf Exploration Production developed a system for automatic handling of single wells and complete field sections. Some of the results were reported in Ref. 3 and in Ref. 4. The name for these technologies are “Full control of wells” or FCW. FCW consists of two main parts:

1. **An individual well management level**, referred to here as Monowell
2. **A collective well management level** referred to here as Multiwell, which controls a series of wells in relation to the oil and gas facilities.

The system is the first and still the unique field-applied dynamic control that uses both the oil production choke and the lift gas control valve of each well under continuous gas-lift, see Fig. 6. The control schemes account continuously for simple surface measurements on the wells and on the facilities.

**Control concepts**
Well production is optimized on the basis of technical constraints and economical and strategic objectives, while taking into account safety and production rules, reservoir extraction policy, (max. flow rate per well, production quotas etc.), well bore-formation interface (sand control, max. dP etc.) and capacity of the installations (upstream & downstream). The system is based on universal sequences and fuzzy logic without any computation. It is a sequence-based control dynamically adjusting lift gas and oil choke.

The technology features individual well management including effective but gentle and controlled unloading of the well that overcomes the energy threshold of the well. The system is able to automatically reduce the injection gas flow rate until a desired level or the instability region, and thereafter continuously adjust the gas flow to assure stability of the flow and pressure in the well. The control stabilizes operating points that are unstable under standard operation through an enhanced path during unloading and transition. The instability is field proven to be path dependent.

In case of substantial variations in flow rate, the adjustments on the well are modified immediately to bring the well back to its normal regime.

The Multiwell control module ensures collective management of wells by sequential start and restart of a group of wells, for example all wells at an offshore platform. The wells are started up in pre-determined sequence. Optimization of the gas lift network is based on selective load shedding of the wells. Based upon measurements e.g. separator level, export pressure or lift gas supply pressure, the system automatically observes bottlenecks that might lead to process shutdown. In such cases the system automatically either reduces the flow from the wells in a pre-specified order or shutting in a number of wells.

Fig. 7 gives a real example from Grondin field that shows how FCW can influence the behavior of a well; more production with less lift gas.

**General Architecture**
The system includes the following major elements (see Fig. 8): well equipment (with gauges and actuators), gas lift and oil networks (with gauges), a local control system, and one or more operator stations.

The well equipment required for each well includes an actuated production choke and a gas lift injection control valve plus transmitters to measure wellhead and casing pressure, injection gas flow rate and optionally liquid flow rate, production choke position and oil production choke pressure drop.

The casing and tubing valves used for shut down are managed only by the PSD and ESD systems. Only information about shut down is given by the PSD and ESD systems to the automation system. Fig. 9 shows a topology drawing of the instrumentation.

The local control system commands the wells, receives measurements from the various sensors installed in the wells and in the gas and oil networks, controls gas injection flow rate and liquid production. Program logic is implemented here. The operator station is used in order to monitor the various measurements, perform commands like well start, well stop and selection of operating mode, consult the well history, diagnose system operation and update parameters.

**Experience**
Today these technologies have been used for nearly ten years on more than 200 wells. The experience shows that the described concepts for automation increase the average oil production from 5 to 20%, and a decrease in gas lift usage from 5 to 20%.

In this article we would like to elaborate how these benefits occurs.

**Increased Process Uptime**
Automatic control of the wells means both smooth and efficient start-up. Thus, the start-up surge is dampened, and the well is stable after the start-up phase. Especially there is no more heading production mode. The major need of operation for the oil production chokes and the lift gas injection control valves is during the restart-up phase. In case of instability, the control program achieves quickly corrective actions including a choke back which dampers the surges.

The total production throughput is often limited by the capacity in the separators. This means that the separator train is heavily loaded. A fluctuation in flow or composition from the wells leads to disturbances in the separation process. This gives sometimes high-high alarms of level or pressure in the
A New Model-Based Automatic Control Approach

In this section we will present a new model-based automatic control approach for gas lifted wells. This method heavily relies on dynamic (transient) gas lifted well models, and can partly be viewed as further development of the method presented in the previous section. It is another approach for the automatic stabilization of gas lifted oil wells and thus maximizing the lift gas efficiency, which captures the well and process knowledge in a dynamic model.

The main ingredient in the model-based gas lifted well controller concept is a dynamic (transient) model of a gas lifted well from which a model-based stabilizing gas lifted well controller can be designed. By using such a model-based concept it is possible to stabilize the pressures, temperatures and flow rates of a gas lifted well in an operating point that is unstable in open-loop (i.e., when no active control is used). The model-based stabilizing gas lifted well controller makes sure that the control error, the difference between the (externally given) optimal reference operating point and the real operating point, at any time is kept at a minimum. An appealing feature of the model-based stabilizing gas lifted well controller concept is that it is able to stabilize gas lifted wells with different measurement devices (sensors) available for control purposes.

Fig. 10 shows a schematic of the new model-based stabilizing gas lift controller structure. The model-based gas lift controller uses an externally given optimal reference point and one or more process measurements (or a model-based estimate of these) to calculate the opening of the production choke and/or the gas injection choke. The preferred mode for the externally given optimal reference point is the specification of the optimal LGR (gas rate through the down-hole gas injection valve).

Consider again Fig. 5 that shows a lift performance relationship curve for a North Sea gas lifted well generated using the dynamic multi-phase flow simulator OLGA. The shape of the lift performance curve is typical for gas lifted wells. The solid curve corresponds to injecting lift gas directly through the lowest gas injection valve at constant rate. Obviously, this is not possible, and the dotted curve shows the resulting average production when the lift gas is injected at constant rate through the gas injection choke. In both cases the resulting oil production rate are shown as a function of the amount of injected lift gas. Due to unstable production at low gas injection rates when injection the lift gas through the gas injection choke, it is seen from Fig. 5 that the typical loss in average production is high for unstable production conditions (dotted curve) as compared to stable operating conditions (solid curve). The results in Fig. 5 agree very well with what was reported in Ref. 1 where a transient simulator was used to remedy gas lift problems. However, a transient simulator alone may only help you to figure out how to improve your gas lift design, whereas capturing the dynamic model in an active control algorithm solves the stability problems without changing the design. Indeed, experiments have shown that with the new model-based stabilizing active controller the well in Fig. 5 may be operated on or in infinitesimal distance from the stable solid curve.
In Fig. 5, it is seen that there is no production when the lift gas injection is zero. Note that this figure is not universally valid. In fact:

1) For high PI wells, the solid curve (stable flow) gives production with no injection but the dotted line (unstable) gives no production for no injection.

2) For low PI wells, the dotted curve has also no production for no injection but the solid curve crosses the dotted curve. Below a minimum lift gas, no stable flow is possible whatever the control is. Below the cross point, it is more economical to produce unstable (intermittent gas-lift).

**A Simple Dynamic Model Structure**

The idea behind the new model-based concept is to analyze and design stabilizing controllers, and, if applicable, estimators based on a dynamic model of the system. For this purpose we have developed a structure for a simplified dynamic non-linear model based on physical principles of gas lifted wells suitable for controller and estimator design. The main purpose with this dynamic model is to describe the interactions between the annular space and tubing which leads to the unstable behavior (heading limit cycles) at low and intermediate gas injection rates. In addition it is necessary that the model becomes stable at high gas injection rates. The idea is to use a simple model basically relying on three differential equations conserving mass in the tubing and casing, and a couple of algebraic equations (of state) for approximating energy and impulse balances. At the cost of a more complicated, yet accurate, model, differential equations describing energy balances and impulse balances may also be included. To sum up, the nonlinear dynamic gas lifted well model consists of:

- Model of the pipes (casing and tubing):
  1. Three ordinary differential equations conserving masses in casing and tubing.
  2. Algebraic equations (of state) relating pressure, temperature, and liquid and gas holdup to each other in casing and tubing.
  3. Algebraic equations for pressure head.

- Model of gas injection choke: An algebraic equation describing the relation between the pressure upstream and downstream the gas injection choke and the mass flow rate through the choke.

- Model of the gas injection valve: An algebraic equation describing the relation between the pressure upstream and downstream the gas injection valve and the mass flow rate through the valve. The equation will vary depending on the type of gas injection valve used.

- Model of the production choke: An algebraic equation describing the relation between the pressure upstream and downstream the production choke and the mass flow rate of gas and liquid through the choke.

The advantages with this simple dynamic model structure are many. Compactness is one appealing feature (only a set of ordinary differential equations and algebraic equations). Secondly, it is able to capture the main dynamic behavior of gas lifted well both at low, medium (unstable operating conditions) and high (stable operating conditions) gas injection rates. Even so important, the model may easily be linearized, meaning that it is suitable for linear controller and estimator design. In addition, the parameters in the model can be tuned so that the model fits measured real time-series of pressures, temperatures, and flow rates from a gas lifted well.

**Linear Models For Controller Design**

A nonlinear dynamic gas lifted well model in accordance with the proposed structure may be used directly as part of the model-based stabilizing gas lift controller shown in Fig. 10. However, it is sometimes difficult to design a model-based controller based on a nonlinear model. The preferred way for utilizing the derived nonlinear model will therefore be linearization. To locally capture the dynamic behavior of an unstable operating point of a gas lifted oil well, the nonlinear model in accordance with the structure described above may be linearized in the current operating point of interest. Representing the local dynamics of a gas lifted well using a linear state-space model or, equivalently, a transfer function model then locally captures the dynamic behavior in the neighborhood of an unstable operating point. Several authors have previously used transfer function models for locally representing the dynamics of gas lift wells in order to derive stability criteria (see Refs. 4, 7 and 8).

We have developed two efficient ways of generating these kind of linear gas lifted well models. One way is, as already alluded to, by (numerical or analytical) linearization of a nonlinear dynamic gas lifted well model in accordance with our invented structure described above. Another way of doing it is by closed-loop identification experiments on a gas lifted oil well modeled in OLGA where the closed-loop system is stable in the operating point in question.

Used in combination with advanced techniques from control theory (see e.g. Ref. 9) the linear local gas lifted well models (as described above) can be used to design model-
based linear locally stabilizing gas lift controllers. In this way, an (optimal) operating point that is unstable in open-loop (i.e., without active control), becomes locally stable in closed-loop (i.e., when the stabilizing gas lift controller is actively used).

In order to generate globally model-based stabilizing gas lifted well controllers, we combine the model-based linear locally stabilizing gas lifted well controllers described above. Each model-based gas lifted well controller will then consist of a family of model-based linear stabilizing controllers, each of which will be valid in a predefined neighborhood of an open-loop unstable operating point, and switching between the controllers will occur based on predefined logical rules. An illustration of this concept is shown in Fig. 12.

Possibilities for Different Control Structures
A nice feature of the model-based controller concept is its flexibility concerning the selection of the particular controller structure to use, i.e., which measurements to use for control and estimator purposes and which chokes to use for active manipulation. The pairing of measurements and manipulation chokes may vary from well to well, and therefore it is important to develop a concept for control that is robust enough to tackle such differences. Several control structures, in line with our general concept shown in Fig. 12, have been simulated based on a software link between MATLAB and OLGA. The gas lifted well is then modeled in the multiphase simulator OLGA and the model-based gas lift controller is implemented in MATLAB, and the experiment itself is run in the MATLAB environment. What is observed in all the simulations of the various model-based controller concepts is that the heading phenomena is eliminated through the active and continuous manipulation of the opening of the production choke and/or the opening of the gas injection choke. Surprisingly, even rather simple control structures are able to cope with the instability. The reason for this is the model-based feature of the controller concept, making the controller able to estimate what is not measured. Indeed, using e.g. only measurements of pressure in the production tubing as input to a model-based gas lift controller, the gas lifted well may be stabilized only through dynamic manipulation of the gas injection choke. Pressure in production tubing may be measured anywhere between the bottom of the well to the wellhead. Fig. 13 shows a model-based controller structure using measurements of wellhead pressure to manipulate the gas injection choke, and Fig. 14 shows a corresponding simulation result for the well in Fig. 5 using the MATLAB/OLGA -link. What is easily seen from Fig. 14 is the efficient way of removing the heading as soon as the controller starts.

Similarly, using only measurements of pressure in casing as input to a model-based gas lift controller, the gas lifted well may be stabilized only through dynamic manipulation of the production choke. A controller structure using this measurement is shown in Fig. 15, and Fig. 16 shows a corresponding simulation result for the well in Fig. 5 using the MATLAB/OLGA -link.

Conclusions
Field experience and simulations demonstrate that more oil can be produced with less lift gas provided that automatic control is applied for stabilization. The production increase is particularly prominent on high PI wells or when having high-pressure lift gas. Stabilisation with enhanced control avoids using lift gas in an inefficient way or introducing continuously a high back-pressure.

Enhanced control of gas lifted wells also gives other benefits. It allows avoiding gas-lifted wells instability under low lift gas injection thus making it feasible to reduce the gas injection rate below the point where instability usually occurs, and it reduces the effect of disturbances.

The sequenced-based automation is widely field proven to stabilise production and is extended for other applications such as ESP and deep offshore risers.

The model based controller described in this article has a potential for improving the control method developed and proved by Elf, in that it on-line accounts for well characteristics and might stabilise more unstable operating points.

References
Fig. 1—Typical lift performance relationship curve for a gas lifted well.

Fig. 2—A schematic of a gas lifted oil well including the most common measurements.

Fig. 3—Unstable production for a gas lifted well – constant gas lift rate = 0.6 kg/s.

Fig. 4—Unstable production for a gas lifted well – constant gas lift rate = 1.2 kg/s.

Fig. 5—Lift performance relationship for a typical gas lifted well. The solid curve corresponds to injecting lift gas directly through the lowest gas injection valve at constant rate, and the dotted curve shows the resulting average production when the lift gas is injected at constant rate through the gas injection choke.
Fig. 6—System overview.

Fig. 7—Example of how the automation concepts influence well behavior.

Fig. 8—System architecture

Fig. 9: Instrumentation overview

Fig. 10—A schematic of the new model-based stabilizing gas lift controller structure.
Fig. 11—An open loop (no active control) transient simulation for an experimental gas lifted well based on a simple nonlinear gas lifted well model.

Fig. 12—A model-based stabilizing gas lift controller consisting of several linear locally stabilizing gas lifted well controllers.

Fig. 13—Control structure for stabilization of a gas lifted well using measurements of wellhead pressure and a model-based controller for manipulation of the gas injection choke. The numbers in brackets refer to Fig. 2.

Fig. 14—Stabilization of wellhead pressure (left) and stabilization of the oil production rate (right) using the control structure in Fig. 13.

Fig. 15—Control structure for stabilization of a gas lifted well using measurements of casing pressure and a model-based controller for manipulation of the production choke. The numbers in brackets refer to Fig. 2.

Fig. 16—Stabilization of casing pressure (left) and stabilization of the oil production rate (right) using the control structure in Fig. 15.