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Gas Coning Control for Smart Wells Using a Dynamic Coupled Well-Reservoir Simulator

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Abstract
A strong increase in gas inflow due to gas coning and the resulting bean-back because of Gas to Oil Ratio (GOR) constraints can severely limit oil production and reservoir drive energy. In this paper we will use a coupled reservoir-well model to demonstrate that oil production can be increased by using controlled inflow from a gas cone as a natural lift. This model was developed in the knowledge centre Integrated System Approach Petroleum Production (ISAPP) of TNO, TU Delft and Shell, and is based on a commercially available dynamic multiphase well simulation tool (OLGA) and a dynamic multi-phase reservoir simulator (MoReS).

In order to give a proof of principle we have implemented a PID feedback controller, which controls the gas fraction in a well by changing its wellhead choke or inflow control valve (ICV) settings, on a realistic test case. We introduce a strategy to find an optimal production set point for this controller and the benefits of using downhole ICVs in comparison to the wellhead choke are investigated.

Simulation experiments show that a PID controller is an effective means to prevent a full gas breakthrough and, moreover, can be used to increase the produced oil rate by tuning ICV settings to achieve an optimal well gas fraction. Results show that the coupled simulations could be significantly more accurate in comparison to stand-alone well or reservoir simulations.

In current operations ICVs are mostly used to completely shut down well segments that experience gas coning. We show that by keeping these ICVs open in a controlled way the - otherwise undesirable - phenomenon of gas coning can be used to increase oil production.

Introduction: Gas Coning Control
Gas coning is a phenomenon where the gas-oil-contact (GOC) of a reservoir slowly moves towards a well as a result of oil drawdown. In case of horizontal or deviated wells this is often a zonal phenomenon, which occurs at a limited amount of perforations, and is referred to as 'cresting' (Figure 1).

At a certain moment in the production life of a gas coning well the gas-oil-contact will reach the well and a gas breakthrough will occur. Upon breakthrough the well will experience a high gas inflow. Largely for three reasons this is an undesired phenomenon. Firstly because the gas phase may start to dominate production, which will deem the well to be uneconomical. Secondly, the inflow of gas may damage topside equipment that is not designed to process large quantities of this phase. Thirdly, after breakthrough the gas cap of the oil reservoir will be depleted fast, taking away its drive energy.

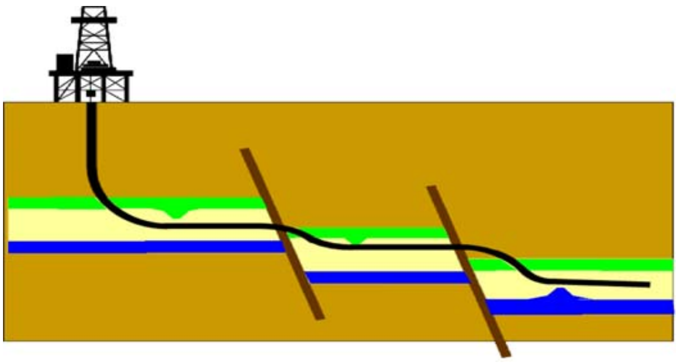

Figure 1: Multizone completion of a horizontal well

The difficulty of containing these three negative consequences lies in the relative speed of a gas breakthrough - typically expressed in hours. Unfortunately the industry is increasingly faced with these hard to contain consequences because many mature fields experience gas coning. Also, oil is increasingly produced from reservoirs like thin oil rims that tend to cone easily.

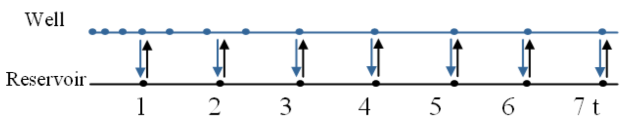

Figure 2: Explicit scheme used to couple a well model and reservoir model: bottom hole pressures from the well simulator and bottom hole flows from the reservoir simulator are exchanged at discrete time intervals

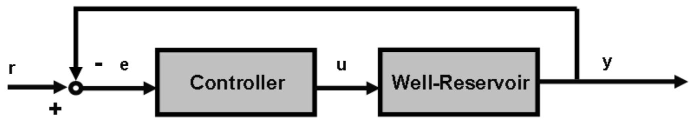

Figure 3: Feedback control applied to output of MoReS model

The most obvious way to prevent a gas breakthrough is to limit the drawdown of a well in such a way that the gas-oil-contact will not reach the well. In this respect the production rate where gas breakthrough will not occur is defined as the 'critical rate'. Many studies have been dedicated to predict the critical rate, gas breakthrough time, and the associated optimal well design, both for horizontal and vertical wells.[1]

Unfortunately production below the critical rate is rarely an economically attractive alternative – this holds especially for thin oil rims. Another disadvantage of production below the critical rate is the fact that the problem of a gas breakthrough is not eliminated; the gas-oil-contact will unavoidably reach the well at some point upon depletion of the reservoir. Most commonly the zones that are experiencing breakthrough are then shut-in. In the absence of drawdown the gas-oil-contact will move away from the well as a result of gravity forces. After recovery, production is resumed until breakthrough occurs again. For reservoirs that experience water breakthrough next to gas coning, or reservoirs that have a low permeability, this is rarely a full recovery however; a high gas inflow can be expected soon after production is resumed.

In this paper we present a different approach to gas coning control than the procedure that was just outlined. We will not restrict production to a predetermined critical rate, nor necessarily terminate production after breakthrough occurs (in this respect an interesting alternative is offered by Jansen et al. (2002) and Eken (2007). Instead the effect of a gas breakthrough is contained by means of a feedback controller. This feedback controller continuously changes the inflow through the ICVs or the wellhead choke of a smart well.[2]

To evaluate the use of this gas coning controller a simulation environment has been built. This software environment allows one to couple the output of a reservoir simulator to external models, like for example a well simulator or a feedback control that is used for gas coning control. We will use this environment to couple a steady-state well model to a dynamic reservoir model (MoReS) in order to:

- Show that the proposed gas coning control strategy can be used to control the gas fraction in a well to a wide range of predetermined set point levels

- Show that the proposed gas coning control strategy can be used to increase oil production by taking the effects of natural gas lift and choking of the production flow into account.

When a dynamic reservoir model is coupled to a well model, the bottom hole pressures from the well model and bottom hole flows from the reservoir simulator are exchanged at discrete time intervals in an explicit scheme – we can think of such an explicit dynamic coupled model as a changing boundary condition for the stand-alone simulators (see Figure 2).

Next to the evaluation that is based on a steady-state well model we will discuss the benefits of using a dynamic multi-phase well model (OLGA) in the coupled simulator. We are motivated to do so because Nennie et al. (2008) have shown that by coupling a dynamic well model to a reservoir model a more accurate description of the characteristic behavior of a gas cone can given: the combination of these two dynamic models can guarantee that both the large time and spatial scales, which are associated with the slow movement of the GOC towards the well (expressed in weeks to months), as well as the transient dynamics of a gas breakthrough (expressed in minutes-seconds), are accurately predicted.

PID Control

In this paper we will consider the use feedback control to contain the effect of a gas breakthrough. Feedback control is essentially a way to bring a measured variable in a process to a certain reference value by means of a controller device. In reservoir management literature feedback control is sometimes referred to as 'active control' – as opposed to 'pro-active' control.[3]

Figure 3 shows the setup in a schematic way. The time varying gas fraction $y(t)$, either in the wellhead or in the ICVs, is used as a feedback signal. Upon comparing $y(t)$ to its set point r the error signals $e(t)$ is obtained:

[1] See for example: Konieczek et al. (2001), Beamara et al. (2001), Wagenhofer et al. (1996) and Ansari et al. (2006)
[2] See also Leemhuis et al. (2007)
[3] See Ebadi et al. (2006)

$$e(t) = y(t) - r \qquad (1)$$

The error signal, which is a direct measure of how far the gas fraction is away from its set point, is used as the input of controller $K(e(t))$. The output $u(t)$ of the controller is continuously updating the ICV or wellhead choke settings in such a way that the gas fraction will converge to its set point:

$$u(t) = K(e(t)) \qquad (2)$$

In our investigation we have used a Proportional Integral Derivative (PID) controller for the controller device. We were motivated to do so because the simplicity and good performance of a PID controller have made it the standard in many industries. An additional advantage of a PID controller is the fact that, unlike more advanced model based approaches, its design asks for little knowledge about the many variables that drive a gas breakthrough. For a PID controller the relation between the controller input and output, which is stated by equation 2, is given by:

$$u(t) = K_p e(t) + K_I \int_0^t e(\tau)d\tau + K_D \frac{de}{dt} \qquad (3)$$

Designing a PID controller that suits our purpose comes down to finding the values for the controller gains K_p, K_I and K_D that make the gas fraction after a breakthrough go to a certain set point and stay there. Even though some tuning criteria for these gains exist they often need to be set by trial-and-error. The choice of the controller gains is driven by two opposite yet equally important boundary conditions: stability and performance. High gains will generally give fast tracking performance but may yield instable closed loop systems, whereas controllers that have a low gain will be stable but show a slow tracking performance.

An important assumption that we make about the feedback signal needs to be highlighted here: we assume the gas fraction can be measured at the valve. Even though this assumption does not hold for current field applications, it allows us to investigate the viability of controlling the gas fraction directly. Also it allows us to look at the viability of techniques like soft sensing, which are currently being developed to derive a model based estimation of the gas fraction distribution in a well as if it was measured.[4]

Dynamic Reservoir Model

The dynamic reservoir model that was used in this study is meant to represent a typical thin oil rim case. The dimensions of the reservoir are 2290 meter by 1830 meter. The height of the reservoir is 230 meter. The topside of the reservoir is located at a depth of 2440 meter, the gas-oil-contact is at a depth of 2520 meter, and the water-oil-contact is at 2610 meter. The horizontal permeability of the reservoir is 200 mDarcy and the vertical permeability is 75 mDarcy. For relative permeability there is segregated flow at the GOC and diffusive flow near de well. The initial reservoir pressure at the GOC is 206.8 bar. The porosity of the reservoir is set to 0.3. The viscosity of oil is 0.6 cp, of gas 0.02 cp and of water 0.3 cp at reservoir pressure. The reservoir has a fixed volume with no flow boundary conditions at the far field boundary and a pressure boundary condition at the wellhead.

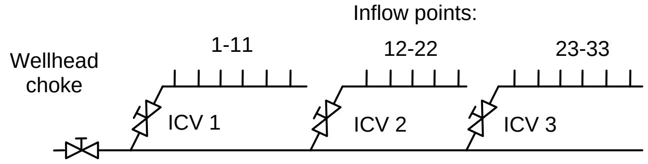

Figure 3: Inflow point and ICV layout of the horizontal well segment.

[4] See for example Leskens et al. (2008), Lorentzen et al. (2003), Verfing et al. (2006), Nygaard et al. (2005) and Bloemen et al. (2004).

Dynamic and Steady-state Well Models

The test case smart well that was used in this study is a horizontal well that is located at a true vertical depth of 2630 meter and has a horizontal section of 430 meters long. It has perforations between 31 meter and 396 meter. The inner diameter of the annulus is 0.12 m (4.7") and the outer diameter is 0.25 m (9.95"). The horizontal section contains 33 inflow points that correspond to 33 grid blocks in the reservoir model. The inflow into the horizontal well is controlled by means of three ICVs (see Figure 3). At the top side a wellhead choke is located with a constant back pressure of 40 bara.

Two types of models of this smart well were used in our study: firstly a dynamic multi-phase simulator (OLGA), and secondly a steady-state well model. The essential difference between these two models is the way they calculate the bottom hole pressure that is exchanged between the reservoir model in the coupled simulator.

The bottom hole pressure of the dynamic model is based on the dynamic multi-phase flow behavior of the oil, gas and water mixture in the well.

For the steady-state model the bottom hole pressure is calculated by means of a simplified horizontal annulus model, which is incorporated in the reservoir simulator, and a lift curve table that calculates the pressure drop in the vertical well section. The lift curve tables contain the pressure drop for different flows and GORs. They were generated by means of the dynamic well model of the test case smart well. The lift curve approach is used to make sure that the steady-state well model gives an accurate description of the dynamic well model and the usage of both in the coupled simulator can be compared. Even though much attention has been spent to getting a close match between the two, the operating point of the steady-state model and dynamic model are slightly different. This difference can partly be attributed to a small difference in the PVT data in MoReS and OLGA. For the same mass gas fraction OLGA has a larger GOR than MoReS. Furthermore, the intake performance relationship (IPR) of the steady-state and the dynamic model is different due the different multiphase flow models used to describe the horizontal part of the well. Both differences result in a pressure offset of about 1 bara.

To illustrate the difference between using the coupled simulator with a steady-state well model and a dynamic well model we will consider the bottom hole pressure change during a gas breakthrough of a case that is described by Nennie et al. (2007). Figure 4 shows that both models predict a significantly different pressure drop development – the 1 bara offset between both models has been compensated for, in order to show this difference more clearly. For the coupled simulation the pressure decline is much faster right after gas breakthrough. In the next sections the difference between using the steady-state well model and the dynamic well model in the coupled simulator for the purpose of gas coning control is studied into more detail.

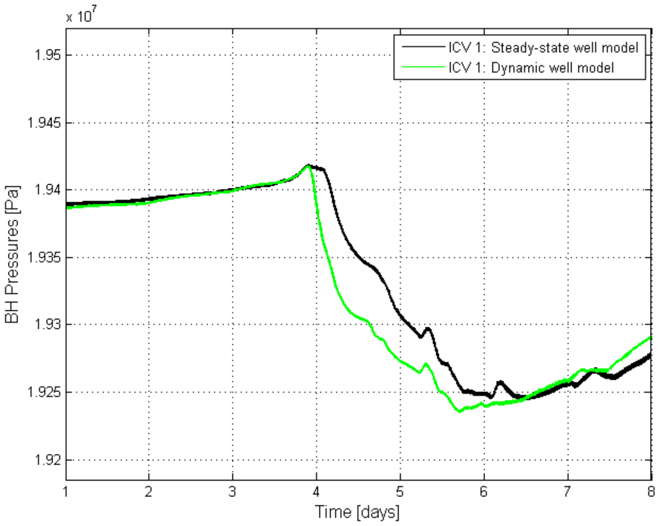

Figure 4: Bottom hole pressure at the ICV1 versus time during gas breakthrough for coupled simulator using a steady-state well model (black) and a dynamic well model (green).

Controlled Gas Breakthrough

To investigate the effectiveness of a PID controller as a tool to contain the effect of a gas breakthrough two strategies have been considered: controlled inflow through ICVs and wellhead choke control. Both strategies have been evaluated by incorporating, for the sake of computational efficiency, the steady-state well model in the coupled well-reservoir simulator. At the end of the paper we will discuss the specific benefits of using a dynamic well model in this simulator for gas coning controller design.

ICV control

Multiple set points for the gas fraction in the ICVs were used, ranging from 5% to 40%. For each of these set points a controller was designed to guarantee stable production after the occurrence of a gas breakthrough. The performance of these controllers is illustrated by Figure 5, which shows the controlled gas fraction in ICV2 for each of these controllers. From this figure we can observe that, especially for the lower values, the set points are reached after a high overshoot (up to 100 %). The long settling time is also an issue: it takes about 5 to 10 days to reach stable production at the desired set points. This settling time is relatively long when we compare it to the speed of the breakthrough, which happens largely in about 5 days.

Typically the settling time and the overshoot can be decreased by increasing the controller gains or decreasing the time interval between choke adjustments. Unfortunately increasing the controller gains is not an option here because only 'weakly' tuned controllers, which have low gains, proved to stabilize the closed loop system in our application.

The results in Figure 5 offer a comparison of different controlled production set points for ICV2. To see how ICV1, ICV2 and ICV3 behave in comparison to each other we will now specifically consider the results for the set point of 21% in Figures 6-7.

Figure 6 shows that each ICV has a different breakthrough time, as well as a different rate of breakthrough. Initially ICV1 will break through. The PID controller that keeps the gas fraction in this ICV at 21% will promptly react upon reaching this set point by gradually closing the ICV (Figure 7) until the moment that the gas fraction is at its set point.

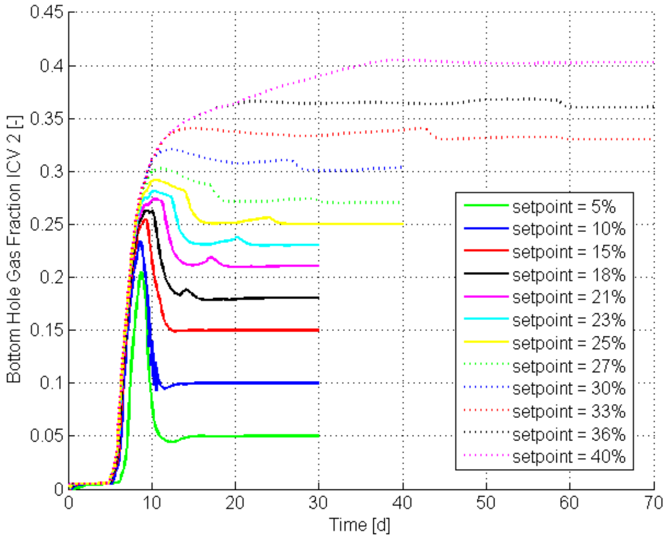

Figure 5: Controlled gas fraction in ICV 2 plotted as a function of time for set point ranging from 5% tot 40%. The simulations were started a few days before the gas breakthrough.

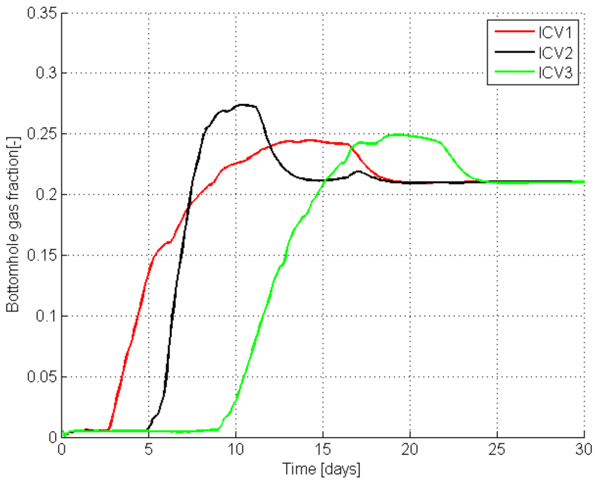

Figure 6: Controlled gas fraction in ICV1, ICV2 and ICV3 plotted as a function of time for set point of 21%.

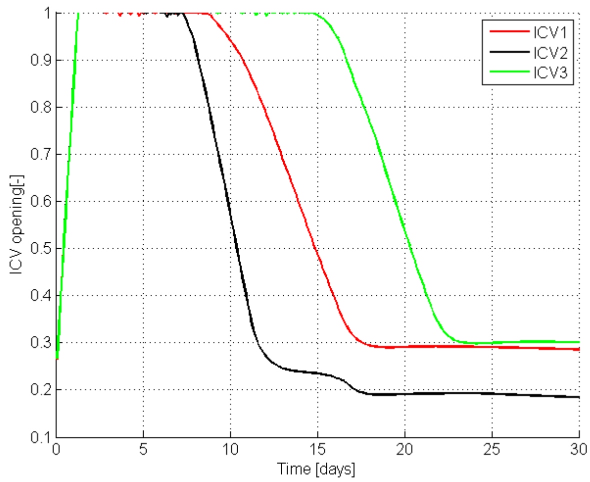

Figure 7: ICV settings as a function of time for controlled production set point of 21%. 0 = ICV closed and 1 = ICV open.

Wellhead control

Figure 8 shows, at the production set point of 21%, how the controlled gas breakthrough develops as a function of time in case of wellhead control. When we compare this figure to Figure 6, which displays similar results for ICV control, it can be observed that in both cases a PID controller is an effective means to stabilize production. In case of ICV control this is achieved by controlling each ICV to its optimal set point after breakthrough in a certain zone of the horizontal well. For wellhead control this is not the case; even though stable production at the wellhead is guaranteed, there are significant gas fraction differences among the ICVs.

Considerations about Choke and ICV Design

A number of observations can be made that are related to the design of chokes and ICVs from the discussed results.

Figures 6-7 show that the relative fast transient behavior of a gas breakthrough (order of hours) asks for a fast adjustment of ICV setting in order to limit the effect of overshoot. From the point of view of controller design such a fast adjustment can be achieved by means of high controller gains or small time interval between ICV adjustments. Since we found that in our case only ‘weakly tuned’ controllers stabilize the closed loop system, decreasing the time interval of ICV adjustments (2.5 hours for Figures 6-7) would be the only option. Form a hardware point of view there are two stringent limitations to decreasing this time interval however. Firstly, ICVs cannot be closed much faster; their closing time is typically in the order of hours. Secondly, the operational lifetime of an ICV is limited to a certain amount choke adjustments.

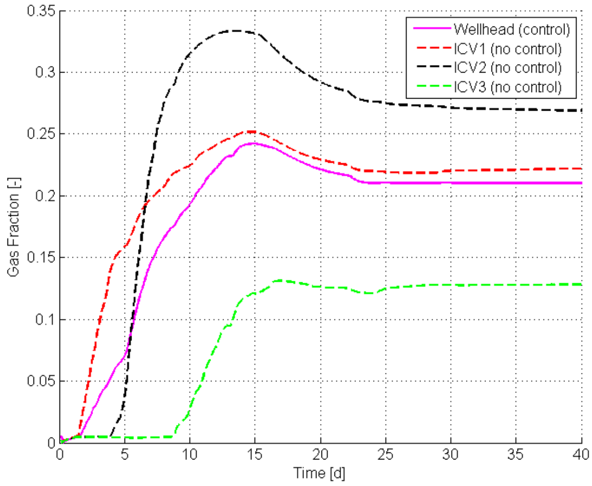

Figure 8: Controlled gas fraction in case of wellhead control plotted as a function of time for set point of 21%. The uncontrolled gas fractions in the ICVs are shown by means of comparison.

Another issue regarding the performance of ICVs or chokes as actuators in a feedback control system is the linearity of their operating range. We found that the linearity of this range strongly affects the stability of the closed loop system. For example: a choke that effectively reduces the flow rate when it is closed for more than 80% will typically result in oscillating outputs. In order to stabilize the closed loop system one can then either lower the controller gains, or reduce the choke diameter in such a way that a more linear inflow performance is obtained. As such selecting the right choke dimensions comes down to finding a balance between operating range and production rate.

Optimal Production

In the previous section we showed that a PID controller can be used to control the gas fraction of an oil well to a wide range of set points after gas breakthrough has occurred. We will now address the issue of selecting an optimal set point for the controller.

For our investigation we will define the optimal production set point as the gas fraction that yields the highest possible controlled oil mass flow at the wellhead. This optimal oil production rate is a balance between two drivers that strongly depend on each other

- Choking the flow, which is necessary to control production to a certain set point gas fraction
- Effect that multi-phase mixture density changes have on the production rate

The net effect of these opposite forces is a gas fraction that optimizes the oil production rate in a well. This optimum is case specific because it is determined by the mixture properties of oil and gas, and also depends on the well geometry and reservoir properties. To illustrate this we will consider the ‘natural lift effect’. This is the phenomenon that gas is good for lifting oil, but can decrease the production rate because high gas rates cause a large frictional pressure drop.

Figure 9 shows the influence of the ‘natural lift effect’ on our test case by varying the well length of the smart well. For wells up to 2000 m there is no ‘natural lift effect’ because for these wells an increase in gas fraction leads to a decrease of the oil production rate. For deeper wells the ‘natural lift effect’ can increase the oil production rate however. The wells of 2500 m and 3500 m illustrate this: an increase in gas fraction causes an increase in production, but from a certain gas fraction on frictional losses caused by high gas speed reduce production. For the well of 5000 m production can only be started when the bottom hole gas fraction is 10%, which implies artificial lift will have to be used.

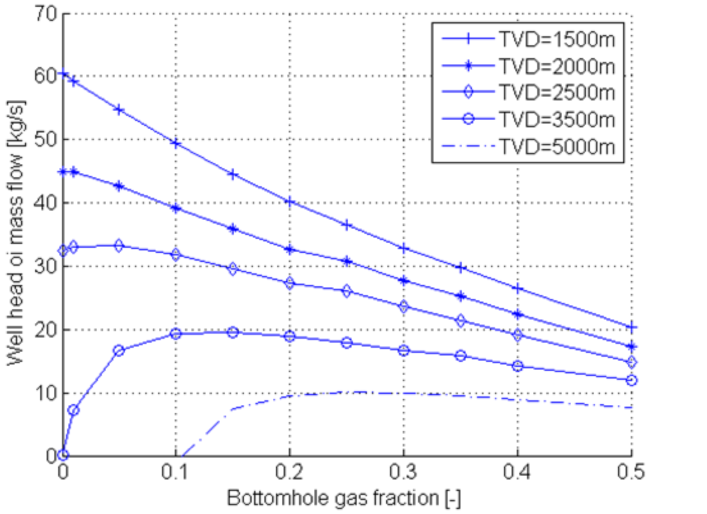

Figure 9: Influence of True Vertical Depth (TVD) of our test case well on the 'natural lift effect'.

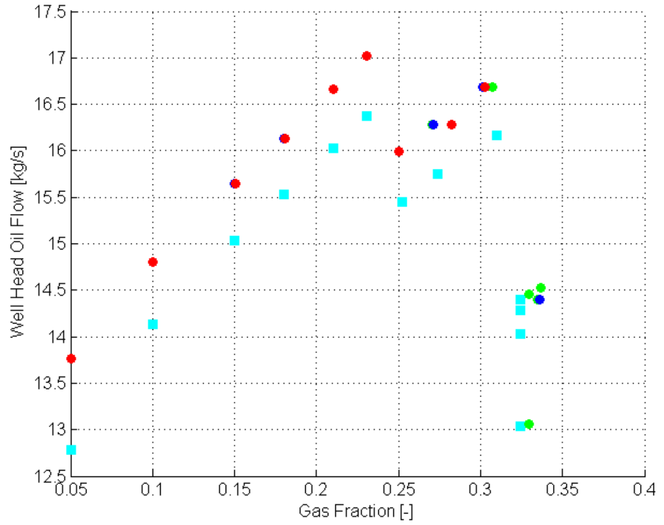

Figure 10: Wellhead oil mass flow plotted as a function of the gas fraction in: wellhead (squares), ICV1 (red), ICV 2 (blue), ICV3 (green).

For our test case the optimal production set point was investigated for a range of gas fractions between 5% and 40%. Of each set point the average production over a time window of 2 days was considered after convergence of the controller. Both bottom hole inflow control by means of ICVs and wellhead control were considered

Figure 10 shows the average stable oil production at the wellhead for multiple set points in case of wellhead and ICV control. The resulting optimum curve shows that the oil production rate of our test case will be optimal at a gas fraction of around 21%. This optimal gas fraction for gas coning control should not be confused with the optimal gas fraction for wells that use an artificial gas lift, because there is a fundamental difference between the optimization strategies of both approaches. In case of artificial lift, the production rate is not choked in order to control the gas inflow because gas is added from a supply at the surface. For the approach to gas coning control that is investigated here the opposite is true: the optimal gas fraction asks for choking of the production rate because gas is added by means of a controlled inflow from the gas cone.

Besides the existence of an optimal production set point, three more observations from Figure 10 need to be highlighted. The first observation is the existence of a second, slightly lower, optimum at a higher gas fraction. This was not anticipated in our experiments and needs to be investigated into more detail. We believe the 'dip' between the two optimal gas fractions is caused by a too low density of lift curves around these set points.[5]

The second observation is that the production rate at the wellhead is slightly lower for wellhead control than for ICV control. In the next section we will discuss this difference into more detail. Note that for both types of control the optimum lies at the same gas fraction because the oil and gas properties, as well as the well geometry are the same in both cases.

A third observation is that the optimal production set point will change in time upon depletion of the reservoir because - for example changes in the bottom hole pressure - will affect the optimal gas fraction.

Next to the above observations about Figure 10 it is important to realize how choking and the 'natural lift effect' constrain the oil production. For lower gas fractions the constraint on the oil production is the wellhead choke or ICV opening. For gas fractions higher than 21% the choke opening is no longer the oil production constraint. Here gas will increase the pressure drop in well, which results in a lower production rate. Figure 11 illustrates this fact for ICV control. In this figure a circle, whose size is proportional to the ICV opening, is added to the plot that shows the wellhead oil flow as a function of time; it can be observed that, even though the choke opening increases with the gas fraction, the oil rate decreases.

ICV Control vs. Wellhead Control

To finalize our discussion on optimal production of a gas coning well we will investigate the condition where ICV control has and added value over wellhead control.

The effect of ICV and wellhead control on the oil production rate at the wellhead is displayed in Figure 12. This figure shows that an ICV controller strategy yields a higher production rate than wellhead control during the gas breakthrough. This is because exclusively zones where breakthrough occurs are choked when ICV control is used and the contribution of other zones to the oil rate is not decreased. The net increase in total production, which results from using ICVs instead of wellhead control, is the surface captured between the two graphs in Figure 12. This advantage of ICV control will last until all zones in the well experience gas breakthrough and are stabilized at the same optimal production rate.

[5] See Nennie et al. (2007)

Note that for our test case the 15 day time frame where ICVs are beneficial is much shorter than one can realistically expect in field applications. In such applications the horizontal well will be much longer. As a results of this, the zonal differences in breakthrough behavior among ICVs may be larger and convergence of these differences to a controlled optimal set point will be much slower. The gain of ICV control over wellhead control will be more sustainable in this situation because optimal production - and the associated cumulative production increase - spans a longer time frame than in our test case. This will especially hold for wells where not all zones are affected by gas coning, or where zonal differences in the gas inflow remain; in such situations the use of ICVs is always beneficial over the usage of a wellhead choke. A number of conclusions can be drawn from this comparison when debating between the advantages of using a wellhead choke versus ICVs to contain the affect of a gas breakthrough:

- Both are capable of containing the effect of a gas breakthrough.
- ICVs do this in a more efficient way because zonal optimal production increases the production at the wellhead.
- This advantage will hold until all inflow points that are controlled by ICVs experience breakthrough and are stabilized at the same stable set point.

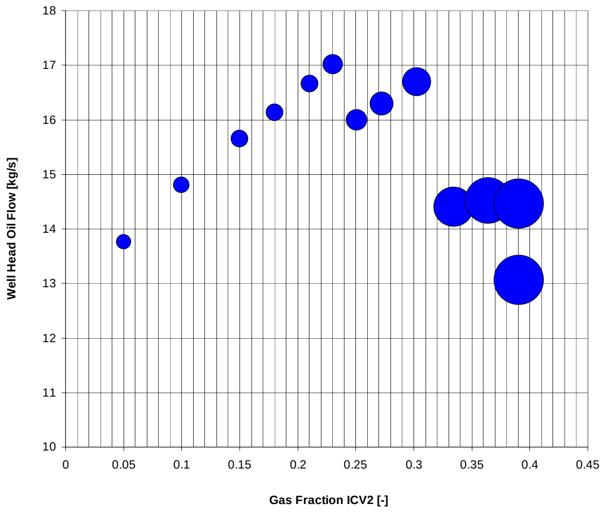

Figure 11: Wellhead oil mass flow plotted as a function of the gas fraction in ICV 2 in case of ICV control. Circle diameter at each grid point is a measure for ICV opening.

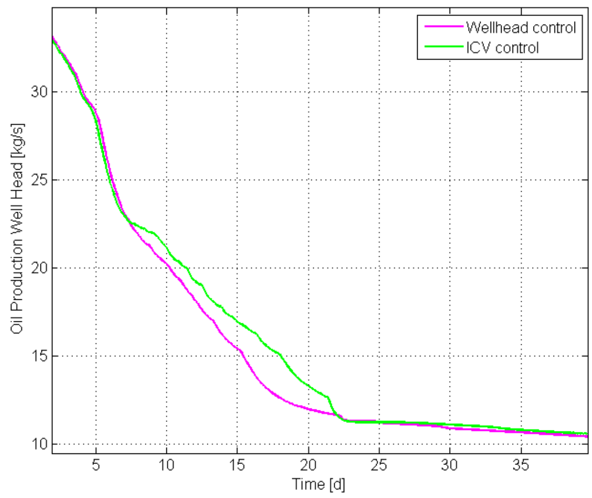

Figure 12: Wellhead oil mass flow plotted as a function of time for wellhead control and ICV Control.

Added Value of Using a Dynamic Well Model

In the previous section we have evaluated the proposed reactive gas coning control strategy by means of a simulation environment that couples a dynamic reservoir simulator to a steady-state well model. In this section we will discuss the benefits of replacing the steady-state well model by a dynamic multi-phase well simulator.

An important benefit of using a dynamic well simulator over a steady-state well model is its ability to model fast transient well dynamics that occur during a gas breakthrough. Especially for the purpose of robust controller design we expect that coupling a dynamic well model to a dynamic reservoir model has a significant added valued. This is because such a simulator can model the dynamic impact of production instabilities (e.g. horizontal slugging) or the effect of disturbances on the controlled closed loop system more accurate. The time scales involved in these dynamics are in the order of seconds and minutes. These transient lie outside the scope of this study however, because gas coning control

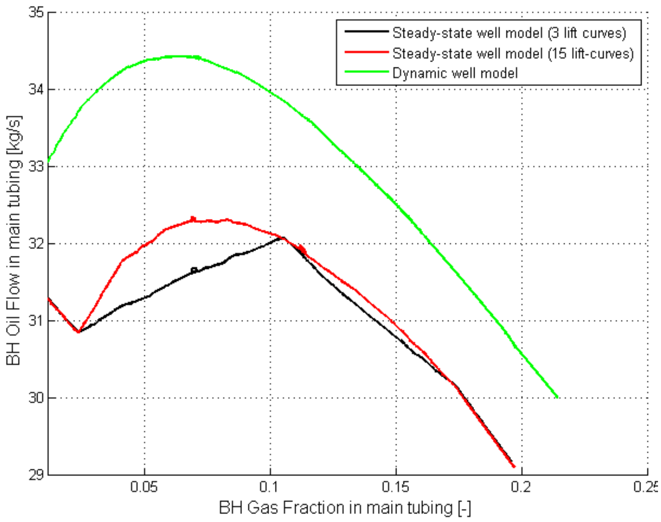

Figure 13: Uncontrolled bottom hole oil flow versus bottom hole gas fraction in the main tubing at the heel of the well.

design is evaluated at time interval – corresponding to ICV and wellhead choke adjustments – of hours.

Another consideration about the benefits of using a dynamic well model concerns the 'natural lift effect', which was identified in the previous section as an important driver in the optimization of a gas coning well. Since the natural lift effect is strongly influenced by oil and gas mixture properties, as well as the well's geometry, it is essential that an accurate well model is used for this optimization procedure. Because such an optimization procedure does not involve transient dynamics, the lift-curves based steady-state model can be used here. In doing so one has to take care that lift curves are used of all GORs and flow rates that have a significant impact on the 'natural lift effect'. The dynamic multi-phase well simulator can serve as an excellent frame of reference here because it can determine the production rate independent of lift curve tables.

The need for a sufficient high density of lift curves in the steady-state simulator is illustrated in Figure 13. In this figure the 'natural lift effect' is simulated by plotting the oil mass flow as a function of the gas fraction for the dynamic multi-phase well model and the steady-state well model. The green line represents a steady-state model where three lift curves are used. As Figure 13 indicates, such a lift curve density does not yield an accurate description of the 'natural lift effect' that is predicted by the dynamic simulator: the optimal gas fraction is a factor two too high and the shape of the 'natural lift' curve around the optimum is not represented correctly. The red line in Figure 13 is based on a steady-state model that uses fifteen lift curves. For this model a sufficient high density of lift curves has been taken around the optimal gas fraction that is predicted by the dynamic simulator. Figure 13 shows that only for such a high density of lift curves the 'natural lift effect' of both the steady-state and dynamic simulator will accurately match for the specific well of our test case. The 7% difference that remains between the oil rate of the dynamic and steady-state well model is caused by the fact that there is a small difference their operating points.

Even though finding the right amount of lift curves is a straight forward procedure one has to bare in mind that the typical amount of lift curves that is used in many production tools may not be sufficient by default to accurately predict the 'natural lift effect.' Using such a model for the set point optimization of a gas coning controller will then results in significant sub-optimal production.

Conclusions

In this study we presented work in progress about dynamically coupled well-reservoir models and their use for evaluating a reactive gas coning control strategies.

Conclusions:

- Using a dynamic well simulator in the coupled simulator results in a significantly different bottom hole pressure change as compared to using a steady-state model.
- For the purpose of evaluating closed loop gas coning strategies the value of a dynamic well simulator is highly dependent on the time scales under investigation.
- PID control is an effective means to prevent a full gas breakthrough and, as such, can be used to limit the gas fraction to, for example to protect topside equipment.
- In current operations ICVs are mostly used to completely shut down well segments that experience gas coning. We show that by keeping these ICVs open in a controlled way the, otherwise undesirable, phenomenon of gas coning can be used to increase oil production as a kind of auto-lift method.
- The optimal production set point of this type of auto-lift method balances the effect of changes in mixture density and changes to the ICV or wellhead choke opening to the production rate.
- In the calculation of this optimal set point, accurate modeling of the 'natural lift effect' is crucial.
- ICV control is a more efficient strategy than wellhead control for wells that have down hole zonal differences in coning behavior; zonal optimization at the optimal production set point results in a higher oil production rate then.

Recommendation for future work:

- Use the dynamic multiphase well model in the developed coupled simulation environment to investigate the impact of transient dynamics on robust gas coning controller design.
- Using this same model compare the benefits of 'fast' wellhead choke strategy as compared to ICV control, which is constrained in the amount and speed of down hole choke adjustments.

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