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Model-based feedback control of oil production in oil-rim reservoirs under gas coning conditions

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ABSTRACT

In oil-rim reservoirs, a thin oil layer lies between an aquifer layer and a large gas-cap. Traditionally, oil has been produced at constant rate from the oil layer. However, the constant-rate oil production strategy may lead to suboptimal performance, as it does not take into account the process dynamics near the wellbore. Motivated by this, first, we present a gas/oil flow model to describe the oil flow dynamics near the wellbore. Second, the high-fidelity simulation result is used to construct a reduced-order model for the design of a Luenberger observer for state estimation. Lastly, a model-based feedback control system is designed to compute the optimal oil production profile that maximizes the net present value (NPV) of oil produced from a horizontal well before gas breakthrough. We demonstrate that the proposed control scheme is able to achieve a high NPV compared to other state-of-the-art oil production strategies.

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1. Introduction

Oil-rim reservoirs are characterized by a thin oil layer, trapped between a large gas-cap and an aquifer layer. During the oil production from the thin oil layer, the difference in mobility between the oil and gas phases drives the gas layer to move downward, which creates an inverse cone shape of gas/oil contact (GOC) near the horizontal wellbore (Tiefenthal, 1994) (Fig. 1). This phenomenon is called gas coning. The gas coning behavior will eventually lead to gas breakthrough, which will in turn decrease the oil production rate due to the limited pumping capacity for oil/gas production (Knut et al., 1994).

In order to understand the gas coning phenomena, Konieczek (1990) developed a simple gravity drainage model in which the oil flow is driven by the hydrostatic pressure gradient in the oil. Specifically, Konieczek (1990) considered only the horizontal flow normal to the wellbore and neglected capillary forces and water coning behaviors. Later, Tiefenthal (1994) improved Konieczek's model by incorporating the fact that the gas rate is proportional to the pressure difference between the wellbore and the reservoir. Since both Konieczek and Tiefenthal performed their analysis based on a one-dimensional model, they were not able to take into account flow variations along the horizontal wellbore. In practice, the length of the horizontal wellbore exposed to gas grows with time and the growth rate changes in response to the oil production rate. Therefore, considering the spatial variation of the oil flow along the horizontal wellbore is necessary. Motivated by these considerations, Mjaavatten et al. (2008) developed a gas-rate dependent gas-to-oil ratio (GOR) model by introducing an additional spatial coordinate in the wellbore direction. Specifically, they assumed that the pressure difference between the reservoir and wellbore varies linearly with the position along the horizontal wellbore. While this model performs well for the prediction of oil production over medium-terms (e.g, the time scale of weeks to months), the short-term prediction in response to a drastic change in the oil production was poor. To handle this issue, Halvorsen et al. (2012) proposed an improved model to take care of the short-term and near-well prediction deficiencies of Mjaavatten et al. (2008).

In horizontal wells, oil is extracted from the wellbore at constant rate before gas breakthrough; however, the constant-rate oil production strategy may lead to a suboptimal performance. Motivated by this, Sagatun (2010) proposed a boundary control scheme by linearizing the aforementioned GOR model (Mjaavatten et al., 2008) to increase the amount of oil produced from a horizontal well before gas breakthrough. Based on this work, further studies were conducted by Hasan et al. (2010, 2011, 2012) where nonlinear control schemes such as backstepping and Lyapunov methods were applied to maximize the Net Present Value (NPV) of oil produced from a horizontal well before gas breakthrough. Specifically, Hasan computed the oil production profile by multiplying the oil

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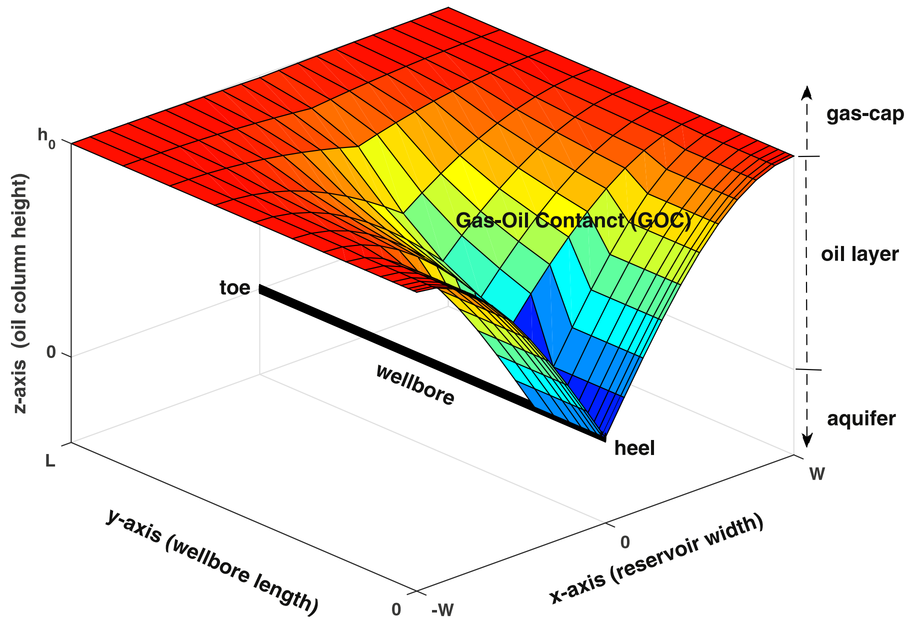

Fig. 1. The 3D contour plot of oil column heights to illustrate gas coning behaviors during oil production from oil-rim reservoirs (Maree and Imsland, 2014).

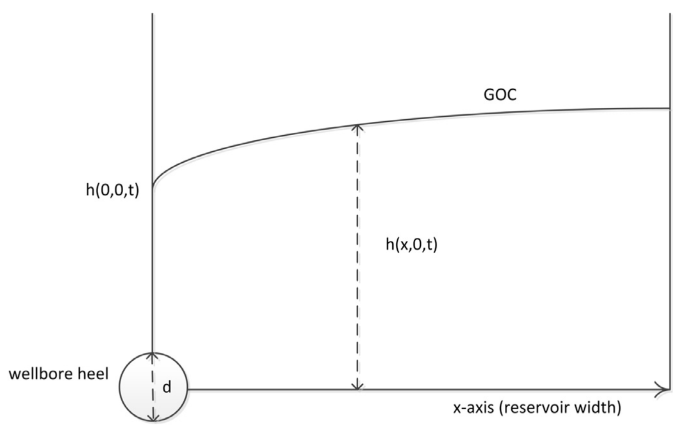

Fig. 2. Oil column height at the wellbore heel, $h(0, 0, t)$ (Sagatun, 2010).

column height at the wellbore heel and a tuning parameter (similar to the controller gain in P-only controllers). The tuning parameter was determined to maximize the NPV of oil produced from a horizontal well before gas breakthrough. Although the control law outperformed conventional constant-rate oil production strategies, it was suboptimal in a sense that the predefined form was used and the process dynamics (e.g., how a gas coning behavior near the wellbore dynamically changes with the applied oil production rate) was not directly incorporated in the design of control laws.

Over the last ten years, the oil and gas production industry has applied model predictive control (MPC) theory to drilling (Asgharzadeh Shishavan et al., 2015; Bellout et al., 2012; Breyholtz and Nikolaou, 2012; Breyholtz et al., 2010; 2009; Eaton et al., 2017; Foss, 2012; Godhavn et al., 2011; Gravdal et al., 2010; Hannegan, 2007) and hydraulic fracturing processes (Narasingam and Kwon, 2017; Narasingam et al., 2017; Siddhamshetty and Kwon, 2017; Siddhamshetty et al., 2017; Yang et al., 2017); however its application to optimize the oil production under gas coning conditions has received very limited attention. While an initial attempt to develop a model predictive control system was made by Maree and Imsland (2014), this study considered optimizing the oil production over a very short period of time (e.g., 10 hours) when the horizontal wellbore heel is close to gas breakthrough.

In this work, we focus on the development of a MPC framework to compute the oil production profile by utilizing real-time measurements to maximize the NPV of oil produced from a horizontal well before gas breakthrough. Unlike other control laws (Hasan et al., 2010, 2011, 2012, 2013), the proposed control framework will compute an optimal oil production profile (with time) by utilizing an approximate process model obtained from the high-fidelity simulation data. Additionally, the lower and upper bounds on the oil production rate will be considered to account for available pumping capacity.

This paper is organized as follows: First, we present a gas/oil flow model. Then, a numerical simulator is developed to solve the gas/oil flow model. Next, a data-based linear approximate model is constructed using the high-fidelity simulation data to design a Luenberger observer for state estimation. Lastly, a model-based feedback control framework is developed to compute the oil production profile that maximizes the NPV of oil produced from a horizontal well before gas breakthrough, which is followed by a series of closed-loop simulation results that demonstrate the controller performance.

2. Gas/oil flow model

The gas/oil flow model presented in this section is initially proposed by Mjaavatten et al. (2008) based on the following assumptions: (1) the oil flow in the vertical direction is neglected, because the oil-layer thickness is much smaller than the reservoir width; (2) since the reservoir width is much shorter than the wellbore length, the oil flow parallel to the wellbore is neglected; (3) the reservoir section is rectangular; (4) the porosity and permeability are spatially homogeneous; (5) the water coning is neglected by assuming the oil-water contact is impermeable.

In Fig. 1, $x \in [-W, W]$ is the spatial coordinate along the reservoir width where W is the half-width of the reservoir and $y \in [0, L]$ is the spatial coordinate along the wellbore where L is the wellbore length. The oil column height is denoted as $h(x, y, t)$ and h_0 is the initial oil layer thickness. Assuming that the horizontal wellbore is located at $x = 0$, in the middle of the reservoir (Fig. 1), we focus on the modeling of the half reservoir. Based on