The Application of Risk Based Methods to Multilateral Well Design

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Abstract

Horizontal and multilateral oil and gas wells are employed to maximise hydrocarbon recovery. To minimise risk of poor well deliverability, producing lengths are currently set using semi-quantitative methods to be longer than required, so that the well connects with sufficient hydrocarbon bearing reservoir. Drilling long producing lengths however increases well drilling cost and risk. Furthermore, attempting to increase deliverability by extending the producing length encounters the "law of diminishing returns" as the flow becomes constrained by tubing friction loss.

This paper seeks to quantify the optimal horizontal well producing length for a given range of reservoir conditions through multiphase fluid modelling, stochastic analysis and parametric economic analysis. A discretised horizontal well model was created, demonstrating how changes in producing length transform the probability density function of production rate. The model also considered the influence of Inflow Control Devices (ICDs), to adjust inflow to match permeability and even out production along the producing length. ICDs can therefore be configured to reduce the risk of gas and water coning, improving hydrocarbon recovery.

1. Introduction

Horizontal and multilateral oil and gas wells are drilled to increase exposure to hydrocarbon reservoirs, particularly in low permeability reservoirs (Joshi 1991). A longer horizontal well is more susceptible to the heel-toe effect, where the pressure differential between the reservoir and well is higher at the heel (Figure 1), compared to the toe due to increasing frictional pressure loss along the well. Therefore production, which is proportional to the pressure differential, preferentially occurs at the heel (Penmatcha et al. 1999), increasing risk of unwanted gas and water coning, where the pressure gradient extends into the gas and water layers. Gas and water are then at risk of breaking into the well, causing their preferential production due to their lower viscosity relative to oil (Al-Khelaiwi et al. 2010). This paper presents a risk based methodology using multiphase fluid modelling and Monte Carlo analysis, quantifying the horizontal well producing length beyond which drilling further does not substantially increase production rate. Parametric economic analysis was used to optimise the producing length of horizontal and multilateral wells. The configuration of Inflow Control Devices (ICDs) was also optimised to maximise hydrocarbon recovery by evening out oil production along the producing length to reduce the risk of gas and water coning.

As per Figure 1, a horizontal well consists of a vertical section (a), which deviates at the heel (b) into a horizontal section located in the oil layer (c) of the reservoir. The furthermost tip of the well is known as the toe (d). In a cased and perforated completion, oil (c), gas (e) and water (f) from the porous reservoir rock flow through perforations (g) in the well casing (h) into the production tubing (i). The multiphase flow in the well continues to the surface subsea tree (j), before passing through a flowline (k) into a surface facility (l).

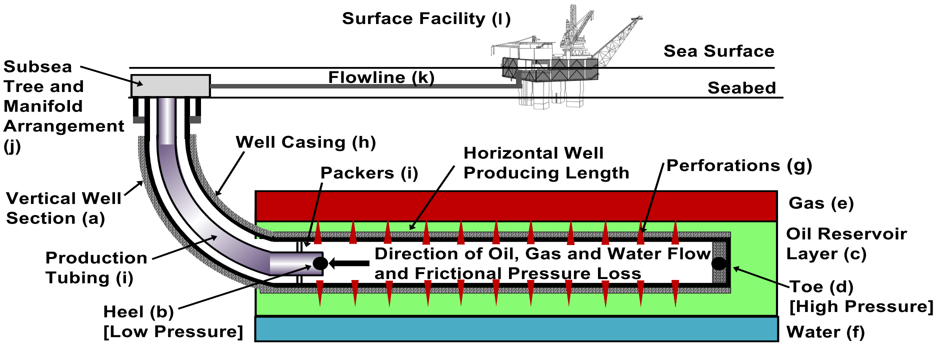

Figure 1 Cased and Perforated Horizontal Well Schematic

1.1 Current State of the Art

Joshi (1991) proposed analytical equations for single phase, steady state inflow through horizontal wells, modelled as infinite conductivity fractures with negligible frictional pressure loss. Based on observations by Salas et al. (1996) that well production rate can be constrained either by reservoir inflow, producing length friction, or tubing friction, the project accounted for wellbore frictional pressure loss. Reservoir oil inflow is proportional to pressure difference between the reservoir and well (Thomas et al. 1998). The project investigated the hypothesis by Penmatcha (1999) that the heel toe effect becomes significant when producing length friction loss, caused by accumulating flow along the producing length, is of similar order of magnitude to the pressure difference, i.e. drawdown, between the reservoir and well. In the heel toe effect, the majority of oil production occurs at the well heel, due to the high pressure difference relative to the reservoir, whilst little production is obtained at the well toe. High heel production rate accelerates oil depletion, causing early heel water production. Water is preferentially produced due to its lower viscosity, leaving unrecoverable oil at the toe (Al-Khelaiwi et al. 2010). The project's discretised well model, based on Thomas et al. (1998) and Ulaeto et al. (2014), coupled reservoir inflow from each segment with cumulative axial flow. The productivity index at every segment was calculated, accounting for variation in reservoir permeability and mechanical skin, i.e. permeability damage due to drilling fluid invasion, along a horizontal well as per Salas et al. (1996).

Inflow Control Devices (ICDs) function as mechanical chokes as per Figure 2, creating a controlled pressure drop to restrict high producing zones near the well heel. This creates a more uniform pressure and oil production distribution along the horizontal well, reducing risk of gas or water coning, thereby improving hydrocarbon recovery (Ellis et al. 2009).

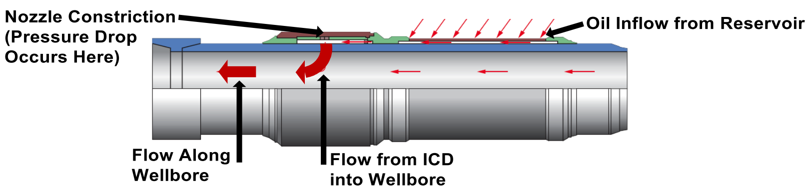

Figure 2 Inflow Control Device Schematic (Ellis et al. 2009)

ICDs automatically adjust, choking back the well across high permeability zones by creating a pressure drop, which restricts the flow rate, as per the Bernoulli equation. ICDs however are passive devices, and their pressure drop versus flow characteristics cannot be adjusted once installed (Ellis et al. 2009). In some cases, improper ICD selection has restricted production from oil reservoirs. This research encompasses multiphase fluid modelling and stochastic analysis to optimise the configuration of ICDs along the well to maximise both production rate and recovery through a more uniform production distribution along the producing length.

1.2 Objectives

A key objective involved investigating the effect of horizontal well length on the expected oil production rate for a given set of reservoir pressure, wellbore diameter and fluid viscosity conditions, using a discretised multiphase horizontal well model. Risk based Monte Carlo simulations accounted for uncertainty in permeability and mechanical skin (permeability damage) due to reservoir heterogeneity. The Monte Carlo simulations, run using a Visual Basic interface with multiphase software including Maximus and Petroleum Experts GAP, investigated convergence of the probability density function of oil production rate due to the frictional pressure loss as horizontal well producing length increased. Parametric economic analysis was utilised to optimise horizontal well producing length. The project applied the multiphase fluid modelling and stochastic analysis approach to optimise the configuration of ICDs, maximising hydrocarbon recovery through a uniform production distribution along the producing length that minimised the risk of gas and water coning.

2. Process

The multiphase horizontal well model was discretised into *n* 50 m segments as per Figure 3, where the axial fluid flow in each segment was equal to the cumulative sum of the flow from the upstream segments, in addition to the reservoir inflow for that segment.

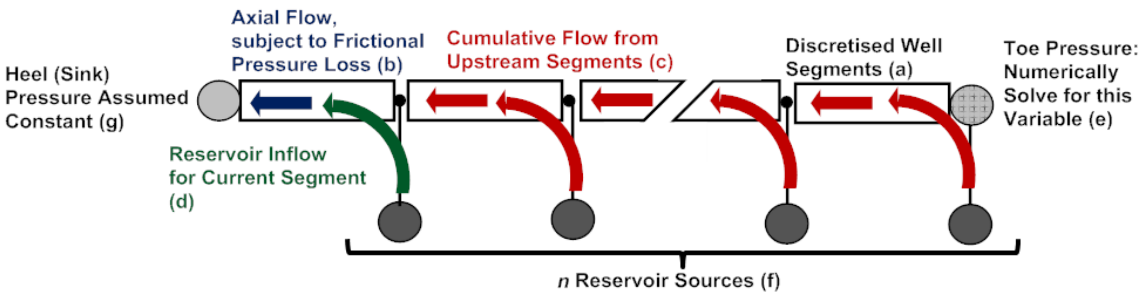

Figure 3 Discretised Multiphase Horizontal Well Model Schematic

The steady-state radial inflow equation (Eqn. 1), derived from the diffusivity equation for an incompressible fluid assuming Darcy's Law, was selected for the model based on its physical applicability to laminar flow in porous media, its capacity to account for mechanical skin, and its established use in the modelling of oil production. The productivity index, J, is a function of reservoir permeability (k), mechanical skin (s), well segment length (h), formation volume factor (B), dynamic viscosity (μ), well radius (r_w), and reservoir drainage extent (r_e).

$$q\left(\frac{\mathrm{stb}}{\mathrm{day}}\right) = \frac{kh}{141.2B\mu\ln\left(\frac{r_e}{r_w}+s\right)}\left(P_{reservoir} - P_{wellbore}\right) = J\left(P_{reservoir} - P_{wellbore}\right) \quad (1)$$

As friction reduces wellbore pressure toward the heel, reservoir inflow, q, which is a product of the productivity index, J, and the difference between reservoir pressure and the wellbore

pressure increases (Penmatcha et al. 1999). Data analysis in Matlab showed the Beta distribution was a reasonable model for reservoir permeability, as permeability has a discernable maximum and minimum. Random variables for permeability and mechanical skin – impairment to permeability due to drilling fluid - were generated with the inverse cumulative distribution function, and used to calculate productivity of each segment. An arbitrary toe pressure was initially assumed as per Penmatcha (1999) and Ulaeto et al. (2014), in contrast with Joshi's (1991) assumption that frictional pressure loss is negligible along the producing well length. Reservoir inflow at the toe segment was calculated as per Eqn. 1.

If wellbore pressure exceeded the bubble point, single phase fluid was assumed in calculating the Moody friction factor. Below bubble point pressure, solution gas was no longer dissolved, causing two phase flow, where pressure drop across each horizontal well segment was calculated in Visual Basic using the Beggs and Brill correlation (Brill and Mukherjee 1999). Toe pressure was numerically varied using Visual Basic's Solver Function until the error between calculated and assumed heel pressure converged to zero. The model was constructed in Maximus, GAP, Visual Basic and NetTool, with flow rates from each model verified against each other for consistency, and validated against production data for accuracy.

3. Results and Discussion: The Optimal Horizontal Well Length

Figure 4 plots the probability density functions of oil production rate, for varying horizontal producing lengths, based on stochastic analysis. These Monte Carlo cases are based on a reservoir pressure of 2500 psia, a well heel pressure of 2400 psia, permeability random variables symmetrically beta distributed between 500 md and 10000 md, a 5.5 inch producing length internal diameter and an oil viscosity of 10 cP at a well temperature of 62°C.

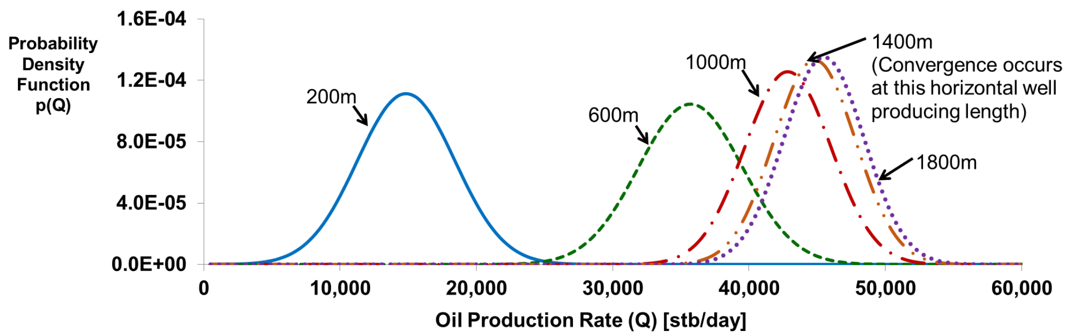

Figure 4 Monte Carlo Model Results: Oil Production Rate vs. Well Length

It is observed that the expected production rate increases with well length, however convergence of the probability density functions around 1400 m indicates that the increases diminish for longer well lengths. This diminishing increase in total production rate is attributed to limited production from toe segments, where well pressure is closer to reservoir pressure. If the pressure is below the bubble point, calculation of the Froude Number and non-slip liquid holdup shows the flow regime shifts from stratified, with liquid occupying the lower section of the horizontal well near the toe, to distributed flow near the heel with gas bubbles dispersed in higher velocity liquid oil. Whilst the flow regime shift has a tendency to decrease the Moody friction factor, it is insignificant relative to the effect of velocity increase. Frictional pressure loss is also proportional to the square of velocity as per the Darcy-Weisbach equation. The increase in flow velocity from 0.3 m/s near the toe, to 5.3 m/s near the heel in a 1400m well, due to the higher reservoir inflow and cumulative flow from upstream segments, creates the rapid decrease in wellbore pressure near the heel.

3.1 Modelling the Effect of Well Diameter on Production and Recovery

As per Figure 5, for a 5.5 inch well, with 100 psi pressure difference between the reservoir and heel, the modelled oil production rate plateaus at 45,000 stb/day beyond a well producing length of 1400 m. This is the optimal well length, maximising the net present value (NPV). Beyond 1400m, NPV decreases due to escalating drilling and completion costs and risk.

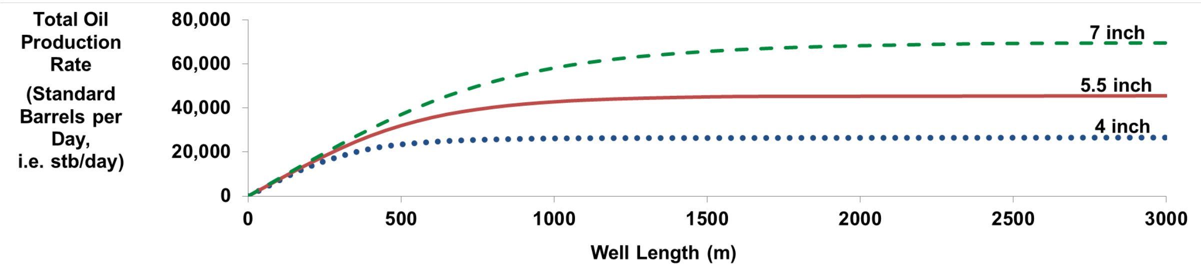

Figure 5 Effect of Diameter on Production Rate and Optimal Well Length

Frictional pressure loss is inversely proportional to the fifth power of diameter, as per Eqn. 2:

$$\text{The Darcy}-\text{Weisbach Equation:} \qquad \Delta P_D = \frac{f_M \rho (\bar{U}^2) L}{2D} = \frac{8 f_M \rho Q^2 L}{\pi^2 D^5} \tag{2}$$

Thus increasing well diameter from 4 inch to 7 inch increases production rate at convergence from 25,000 stb/day to 70,000 stb/day, and the productive horizontal well length from 1000 m to 1800 m, increasing the hydrocarbon proportion recoverable from the reservoir. Increasing well diameter can however be expensive, and pose flow assurance issues in late well life due to higher liquid holdup. An alternative method for increasing production rate is by opening the surface well choke, which has the effect of decreasing well heel pressure. By increasing the pressure difference between the reservoir and well heel to 350 psi, the probability density function shows convergence at a higher production rate of 85,000 stb/day, but a shorter producing length of 1000 m. Hence a lower hydrocarbon proportion in the reservoir is recoverable. In addition, the high pressure difference between the reservoir and well heel increases the risk of gas and water coning, hindering oil recovery from the well toe.

3.3 Optimisation of ICD Configuration for Recovery and Production

Pressure drop across ICDs reduces the pressure difference between the reservoir and the well opening, mitigating risk of heel gas and water coning. ICDs, when improperly configured, however can over-constrain production. The heel pressure was reduced to 350 psi below the reservoir pressure in the multiphase model to determine the increase in toe production as per Figure 6, at the risk of heel gas and water coning. Maximus was used to calculate the optimal size and number of open ICD nozzles required in each well segment, with more toward the toe, to generate a uniform production distribution, at a higher rate, with uniform recovery.

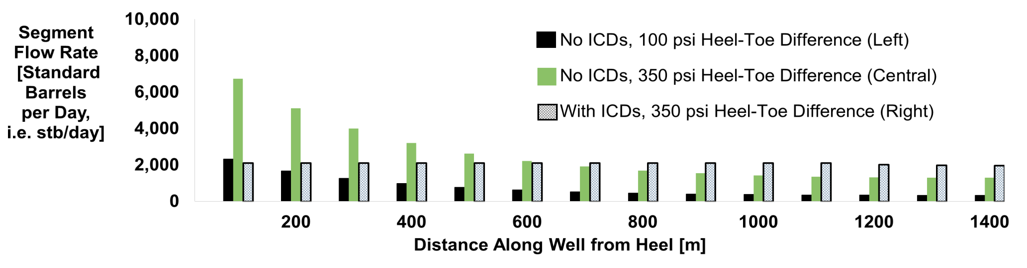

Figure 6 Influence of Inflow Control Devices on Production Distribution

4. Conclusions and Future Work

This paper presents a risk based methodology to quantify uncertainty in production rate through Monte Carlo analysis. It demonstrated that the probability density function of production rate converges as well length increases toward the optimal length, beyond which little production at the toe occurs due to frictional pressure loss. Parametric modelling and stochastic analysis have shown how increasing the diameter increases production rate and the proportion of oil recoverable from the reservoir. During late life, a large well diameter can however cause flow assurance issues. Multiphase fluid modelling in Maximus exemplified the optimisation of Inflow Control Device configuration to allow a uniform production distribution that improves oil recovery, whilst allowing a higher production rate by opening the wellhead choke. It is anticipated this project will lead to further research in technology such as Autonomous Inflow Control Devices (AICDs), which can distinguish between oil, gas and water based on density and viscosity. The application of risk based methods to multilateral and horizontal well design with these technologies can improve production rate and recovery whilst mitigating the risk of gas or water coning.

5. Acknowledgements

Support from Nino Fogliani and Neil Kavanagh in Woodside's Technology team, and CEED Director Associate Professor Jeremy Leggoe has been critical. The author would like to acknowledge the collaboration with the Reservoir Engineering, Drilling & Completions and Production Engineering teams at Woodside Energy Ltd that has been critical to this research.

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