Productivity and Injectivity of Horizontal Wells

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Quarterly Report

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Summary of Technical Progress

A number of activities have been carried out in the last three months. A list outlining these efforts is presented below.

- The third review meeting of the Horizontal Well Industrial Affiliates Program was held on October 19-20 at Stanford. The meeting was well attended and well received. In addition to the project presentations, a number of member presentations were also made at the meeting.

- Example flow problems are being solved by the three-dimensional flexible grid simulator (Flex) as testing and documentation of this code continues.

- Work on obtaining exact well models for a horizontal well or a well of any general profile has continued. The developed code is being evaluated against a commercial simulator (Eclipse) and other in-house simulators for some test problems.

- New work on the application of horizontal wells in gas condensate reservoirs has started. The significant problem being investigated is the productivity impairment due to liquid drop-out near a horizontal well when reservoir pressure falls below the dew-point pressure in a gas condensate reservoir.

- Research work on developing coarse grid methods to study breakthrough times of horizontal wells has continued. The problem of water cresting is currently under investigation. The important issue of optimum grid size and its dependence on various problem parameters is being addressed through dimensionless variables.

- The two-phase wellbore experiments have been analyzed in terms of observed flow regimes and slug frequencies. Equations and methodology of modeling the single phase experiments with radial influx have been developed.

- Work on coupling between reservoir and the wellbore is progressing. The previous steady-state approach is being extended to the more realistic situations of pseudo steady-state and transient behavior. Furthermore, the current model uses constant productivity index which will be made variable as a more general way of coupling flow in the reservoir and the wellbore.

This quarterly report briefly describes the progress made on the last activity listed above. After a brief background on the previous work and an outline of the modeling approach, an example problem will be presented.
Analytical Reservoir/Wellbore Coupling (Tasks 1 and 6)

Introduction

As the length of a horizontal well is increased, its contact with the reservoir increases. But at the same time, the resistance to the flow in the well also increases which has a direct negative effect on the productivity of the well. The overall performance of horizontal wells depends on the balance of these two opposing factors. No reliable tools are currently available that account for both these factors in the evaluation of horizontal well performance. An analytical well-model is developed which can quantify the effects of pressure loss in the well on the overall well performance. A sensitivity study is conducted on the effect of various reservoir, fluid and well parameters on well performance.

Previous Work

Previous work can be categorized into three types:

Type 1: Infinitely Conductive Well

While numerical simulators can evaluate an infinitely conductive well, analytical equations are available only for simple homogeneous reservoirs. Based on the nature of flow, any of the available equations can be used for a quick performance evaluation of a horizontal well in a single phase oil reservoir. Because of the infinite conductivity assumption in all these analytical treatments, their predictions are accurate only when the pressure drop in the wellbore is insignificant. A numerical simulator, on the other hand, can be used for a thorough analysis of any complex reservoir. Unfortunately, at the present time, none of the commercial simulators rigorously account for the wellbore pressure drop.

Type 2: Wellbore Coupled to an Analytically Approximated Reservoir

Realizing the importance of wellbore pressure drop, a few groups have recently developed some simple techniques to evaluate the wellbore frictional effects. This section outlines the available methods that couple the wellbore to an analytically approximated reservoir. The behavior of many homogeneous, single phase reservoirs can be approximated analytically. Many reservoirs are in reality more complex and cannot be represented analytically (heterogeneous, multiphase flow, etc). None of the approaches presented in the literature take into account multiphase flow, or radial inflow effects in the wellbore.

Stone et al. [1] used the model of Chow & Ransom [2] for wellbore pressure drop calculations. The flow from reservoir to the wellbore was calculated using the productivity index (PI) concept and the PI was assumed to be constant. The equations developed were solved using the Yale sparse matrix package.

Dikken [3] presented an analytical model that couples the wellbore to the reservoir with turbulent flow in the wellbore. By using single phase flow frictional pressure drop calculations in the wellbore, the wellbore was linked to the reservoir using material balance. Both laminar and turbulent flows in the reservoir were considered. For turbulent flow, Blasius' formula was used to compute the friction factor. Dikken solved this problem analytically for an infinite horizontal well and numerically for a finite horizontal well.
He assumed that the productivity index is constant along the well, which is placed in a reservoir with constant pressure boundaries. End effects and hence the spherical flow at the ends of the finite acting horizontal well were ignored and no transient flow was considered.

Islam et al. [4] developed a model for radial influx into the wellbore by numerical analysis. They suggested that bubbles created at the perforations due to radial influx and jet like flow through the perforations induce additional turbulence in the wellbore. They didn’t show how the well was linked to the reservoir, although they stated that hybrid grids were used in the simulator near the well.

Novy [5] coupled the reservoir to the wellbore in a manner similar to Dikken’s model. Volume balance of fluids leaving the reservoir and entering the wellbore was used to accomplish this coupling. The problem was formulated as a boundary value problem and was solved using a finite-difference scheme. While Dikken’s model cannot be applied to gas recovery (only oil recovery), the model by Novy can be applied to single phase gas or oil flow. Novy suggested that if the pressure drop in the wellbore is more than 10% of the drawdown, then it is important and should be considered. He showed that for laminar oil flow, friction reduces production rate by at least 10% when the wellbore pressure drop is more than 15% of the drawdown. He provided graphs that show that 1/3 of all oil wells and 3/4 of all gas wells as of 1992 in the world were not affected by friction in the wellbore. This is either due to low flow rates or large well diameters.

Ozkan et al. [6] did a similar kind of analytical coupling as Dikken except that they used the solution based on Green’s function to describe the flow in the reservoir, while Dikken used a PI relationship. Ozkan et al. used only the infinite acting line source model to describe the flow in the reservoir. The model was presented in terms of dimensionless variables.

Landman [7] improved Dikken’s model by allowing PI to vary along the well length. PI can vary along the well due to variation in perforation density, formation permeability or flow characteristics (radial, spherical etc). Spherical flow at the end of the well was taken into account by varying the boundary condition while solving the problem.

Type 3: Wellbore Coupled to a Numerically Approximated Reservoir

In the following papers, a wellbore pipe flow model was linked to a numerical simulator.

Folefac et al. [8] concluded that well length, well diameter and perforated interval have the most significant effect on the magnitude of pressure drop in the wellbore. They used a drift flux model in the wellbore and allowed for inter-phase mass transfer in the wellbore using an equation of state. They state that production logging shows variation of flow rate along the well, which could be due to pressure drop in the wellbore.

Brekke et al. [9] developed a network wellbore simulator, called HOSIM, which can calculate pressure drop with up to three phases in the wellbore. Their approach is modular and any new developments can be easily implemented. However, the network model, representing the wellbore, has to be built on a PC before it can be coupled to the reservoir. Any of the three existing multi-phase flow models built in the code can be chosen. Eclipse is used for reservoir simulation. The reservoir (Eclipse) and wellbore (HOSIM) were connected using the PI approach. PI is allowed to vary with time and location.
along the well length. It can be calculated from Eclipse runs by slightly disturbing the
flow rate and then internally calculating \( \frac{dQ}{dP} \) during every iteration.

**Modeling**

In this section, a brief description of our general method of modeling is presented. Con-
sider a simple case with a horizontal well located in the center of a cylindrical reservoir.
The flow is assumed to be at steady-state both in the reservoir and in the wellbore. We
first define production loss in terms of wellbore pressure drop and drawdown as follows:

(I) **Production Loss vs. Pressure Drop Ratio**

The following parameters are used:

1. PI = productivity index of the well in rbbl/d/psi
2. Q = total flow rate from the well in rbbl/d
3. \( J_s = \frac{PI}{L} \) = productivity index per unit length of the well (assumed constant)
4. \( p_{w,0} = p_{w,x=0} \) = pressure at the heel of the well in psia
5. \( p_e \) = pressure at the reservoir boundary in psia

If \( q_s(x) \) is the flow in the reservoir per unit length of the wellbore, then

\[
q_s(x) = J_s[p_e - p_w(x)]
\]

Integrating the above equation gives the total flow rate from the well as,

\[
Q_{w,fric} = \int_{x=0}^{L} q_w(x)dx = \int_{0}^{L} J_s[p_e - p_w(x)] = J_s p_e L - J_s \int_{0}^{L} p_w(x)dx
\]

When there is no pressure drop in the wellbore, then

\[
Q_{w,nof} = \int_{x=0}^{L} q_w(x)dx = \int_{0}^{L} J_s[p_e - p_w,0] = J_s L[p_e - p_w,0]
\]

Production Loss, P.L. =

\[
\frac{Q_{w,nof} - Q_{w,fric}}{Q_{w,nof}} = \frac{J_s L(p_e - p_w,0) - J_s p_e L + J_s \int_{0}^{L} p_w(x)dx}{J_s L(p_e - p_w,0)}
\]

\[
= \frac{\frac{1}{L} \int_{0}^{L} p_w(x)dx - p_w,0}{(p_e - p_w,0)} = \frac{\frac{1}{L} \int_{0}^{L} [p_w(x) - p_w,0]dx}{[p_e - p_w,0]}
\]

Hence, P.L. = \( \frac{\text{average wellbore pressure drop}}{\text{drawdown}} \)
(II) Flowrate vs. Length

We have already assumed that the flow in the reservoir can be represented by Eq. (1). Mass balance gives the following equation for the flow in the wellbore:

$$\frac{d}{dx}q_w(x) = -q_s(x) \quad (5)$$

where $q_w(x)$ is the flow rate in the wellbore and it varies along the length of the well. Combining the above two equations we have

$$\frac{d}{dx}q_w(x) = -J_s[p_e - p_w(x)] \quad (6)$$

Using boundary conditions,

$$\frac{dq_w}{dx}|_{x=0} = -J_s[p_e - p_{w,0}] = -J_s \Delta p_0 \quad (7)$$

and

$$q_w,x=L = 0 \quad (8)$$

yields a general equation for well length as a function of $q_w(x)$:

$$L - x = \int_0^{q_w(x)} \frac{dq_w(x)}{\sqrt{2J_s \int_Q^Q \frac{dp_w}{dx} dq_w(x) + [J_s \Delta p_0]^2}} \quad (9)$$

Since at the heel, $q_w(x = 0) = Q$, the above equation can be expressed as,

$$L = \int_0^Q \frac{dq_w(x)}{\sqrt{2J_s \int_Q^Q \frac{dp_w}{dx} dq_w(x) + [J_s \Delta p_0]^2}} \quad (10)$$

Using Eq.(10), we can calculate the required length $L$ for a horizontal well, to produce a flow rate $Q$ with a drawdown of $(\Delta p_o)$ at the heel. Using Eq.(9), for a well with a given length $L$ and drawdown $\Delta p_o$, the flow along the well $q_w(x)$ can be calculated. Also, based on this information, the variation of pressure along the well length, $p_w(x)$, can be calculated and substituted in Eq.(4) to obtain the P.L.

Equation (10) is independent of the method of calculating $\frac{dp_w}{dx}$. As long as $\frac{dp_w}{dx}$ can be written as a function of the variable of integration in Eq(10), $q_w$, the above equation poses no problem. For single phase oil flow, we can write:

$$\frac{dp_w(x)}{dx} = f[\frac{\rho U^2}{2D}] = f q_w^2 \left[ \frac{8\rho}{\pi^2 D^4} \right] \quad (11)$$

"f" in the above equation is the Moody friction factor and is a function of pipe roughness and flow rate $q_w$. 


Production Loss vs. Pressure Drop Ratio

As shown in Eq.(4), the production loss increases as the pressure drop ratio increases. Using this relationship, we can perform some interesting sensitivity analyses. For all these cases, the productivity index of the well (PI) is assumed to be constant along the well length.

(A) Effect of Well Length $L$

In a reservoir, for a given drawdown, as the horizontal well length increases, pressure drop in the wellbore also increases due to the increase in flow rate. Hence, longer the well, larger the ratio of pressure drops and higher the productivity loss from Eq. (4).

(B) Effect of Pipe Roughness $\epsilon/d$

In a reservoir, for a given drawdown, as the roughness of the horizontal well increases, pressure drop in the wellbore also increases. Hence, rougher the well, larger the production loss.

(C) Effect of Absolute Permeability $k$

In this case two reservoirs are compared. Everything is the same between the two reservoirs except the permeability. When the two reservoirs are producing at the same flow rate, the reservoir with the higher permeability has a lower drawdown. The pressure drop in the well is the same for both cases, because the flow rate and well lengths are the same. Therefore, the pressure drop ratio increases as permeability is increased, resulting in higher productivity loss from Eq. (4) for the more permeable reservoir.

(D) Effect of Flow Rate $Q$

When the flowrate is increased, the pressure drop in the reservoir increases linearly due to laminar flow. But, the pressure drop in the wellbore can increase at a much higher rate due to turbulence in the wellbore. Hence higher flow rates give larger pressure drop ratios and cause higher productivity losses.

(E) Effect of Viscosity $\mu$

The flow in the reservoir is always considered to be laminar, while in the wellbore the flow can be turbulent. Because of this, an increase in viscosity causes the pressure drop in the wellbore to increase less than the increase in the pressure drop in the reservoir. This gives the surprising result that the productivity loss can be lower for higher viscosity oils.

Example Problem

The above conclusions are illustrated using an example problem. Steady-state, single phase oil flow is considered and the various parameters used are shown in Table 1. Figure 1 shows the effects of well length and well roughness, Figure 2 illustrates the effects of permeability, and Fig. 3 shows the effects of flow rate.
Table 1: Parameters Used in The Sensitivity Example Problem

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal Permeability</td>
<td>3000 mD</td>
</tr>
<tr>
<td>Vertical Permeability</td>
<td>300 mD</td>
</tr>
<tr>
<td>Reservoir Thickness</td>
<td>50 ft</td>
</tr>
<tr>
<td>Outer Boundary Pressure</td>
<td>5000 psia</td>
</tr>
<tr>
<td>Well Pressure at the Heel</td>
<td>4000 psia</td>
</tr>
<tr>
<td>Formation Volume Factor</td>
<td>1.25</td>
</tr>
<tr>
<td>Viscosity</td>
<td>1.0 cp</td>
</tr>
<tr>
<td>Drainage Area</td>
<td>300 acres</td>
</tr>
<tr>
<td>Well Radius</td>
<td>4.3 inch</td>
</tr>
<tr>
<td>Skin</td>
<td>0.0</td>
</tr>
<tr>
<td>Density</td>
<td>40.0 lbm/cu.ft</td>
</tr>
</tbody>
</table>

Figure 1: Effect of Pipe Roughness and Well length
Figure 2: Effect of Permeability

Figure 3: Effect of Flow Rate
References


5. Novy, R.A.: "Pressure Drop in Horizontal Wells: When Can They Be Ignored?," SPE 24941


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