Productivity and Injectivity of Horizontal Wells

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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:

- More than 200 two-phase flow experiments with pre-packed wire-wrapped screens have been completed at the Marathon facility. These experiments include many runs with liquid or/and gas radial inflow at zero, +2°, and -2° inclination angles. All the experiments have been recorded on video tapes which will be used for flow pattern visualization and recognition. Data files are being converted to easy-to-use Excel workbooks. The complete analysis of 1995 and 1996 data is currently underway.

- Example problems have been run to calculate exact well indices for horizontal wells and to assess their influence on production performance. The developed code is being further tested against other available but less general analytical models.

- Research work on the application of horizontal wells in gas condensate reservoirs has progressed. Some results of available models have been verified while a critical evaluation of results of some other approaches is being undertaken.

- Developed correlations for optimum grid size, breakthrough time, and post breakthrough behavior have been further refined. A procedure to derive pseudo functions based on the correlations has been developed and is being evaluated in hypothetical and real field example problems.

- A Masters Report on the effects of horizontal well placement and gravity on sweep efficiency has been completed as a joint project with the gas injection research group (SUPRI-C) at Stanford. The report will soon be released to DOE as a Technical Report.

- A comprehensive study of the effects of heterogeneities on horizontal well performance has been conducted. Various issues such as well models, wellbore pressure drop, cresting models, productivity models, and scale-up methods have been investigated for twenty geostatistical reservoir images generated based on a real field case. A paper on this study will be presented at the SPE International Conference on Horizontal Well Technology in Calgary, Canada, 18-20 of November.

This quarterly report is based on the last activity above. It gives a short version of the paper. An expanded report on this study will be included in the next Annual Report.
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Effects of Reservoir Heterogeneities on Performance Prediction of Horizontal Wells (Task 2)

Introduction

Performance prediction of horizontal and non-conventional wells based on both analytical and numerical tools rarely match actual performance. Even a history matched case with sufficient production data fails to give reliable predictions for long times. In this study we explore reasons for the inability of predictive tools to make accurate predictions. We consider a case where a vertical well has been drilled and cored. Then, we generate twenty consistent geostatistical descriptions of permeability and porosity that are all constrained to hard data obtained from the vertical well. Simulations with these realizations show large differences in production rate, WOR and GOR predictions as a result of variations in reservoir properties. It is also shown that the effect of well index (WI) on simulation results is large. Furthermore, for the example considered, analytical models for critical rate and productivity calculations were found to have limited practical use.

Reservoir Description and Simulation Grid

It is generally acknowledged that lack of knowledge about reservoir heterogeneity is a major cause of the “error bars” associated with performance predictions. Here we will consider a hypothetical example of a horizontal well that is based on data from a real reservoir. The drainage volume associated with the well is 10,000×5,000×100 ft.

We assume that a single vertical well has been drilled. With information from this well and other sources a stochastic model is constructed to produce multiple permeability and porosity images of the drainage volume.

The synthetic reservoir data was fashioned after a fluvial sandstone reservoir with a 70% net-to-gross ratio. Sequential indicator simulation was used to construct a sandstone/shale lithofacies model. An indicator variogram with a vertical range of 10 ft. and an isotropic horizontal range of 100 ft. was considered. This resulted in shales that generally extend over less than 100×100×10 ft. Porosity and permeability in the shales was set to 0.1 and 1.0 mD. The sandstone porosity model was created by sequential Gaussian simulation with a normal scores variogram with a vertical range of 10 ft. and an isotropic horizontal range of 2,500 ft. Sequential Gaussian simulation with the collocated cokriging option in GSLIB (Deutsch and Journel, 1992) was used for the permeability model. The normal scores of porosity were correlated with permeability with a correlation of 0.7. The normal scores variogram of permeability had a vertical range of 3.33 ft and an isotropic horizontal range of 1,500 ft. The data representing a vertical well that goes through the heel of the horizontal well was extracted from an initial unconditional geostatistical realization. The lithofacies, porosity and permeability data from this vertical well were honored in all twenty geostatistical models. The geostatistical parameters for all realizations are identical and the images appear to be similar. For the medium resolution models (see below) the mean shale fraction is 0.311
(std. dev. of 0.007), mean porosity 0.261 (std. dev. of 0.003), and mean horizontal permeability is 430.04 (std. dev. 5.71). The horizontal well is aligned along the X-axis and placed nearly in the middle of the drainage volume.

All stochastic images were created on a 100×50×30 grid (150,000 uniform grid blocks, each block is 100×100×3.33 ft) which is considered to be the fine grid in this study. For the purposes of simulation we have created two sets of upscaled images of the fine grid: a 20×10×10 medium grid (500×500×10 ft blocks), and a 10×5×5 coarse grid (1,000×1000×20 ft blocks).

The grid is nearly uniform in all cases. The upscaling from the fine grid to the other two grids was done using two commonly used methods:

- numerical single phase flow matching in each of the three directions for each upscaled block and the fine grid blocks contained in that block (referred to as medium-f and coarse-f), and
- power law averaging (referred to as medium-p and coarse-p).

Histograms of horizontal and vertical permeability for all three scales are shown in Figure 1. The first of the flow based upscaled realizations was used to estimate the power law averaging exponent for the horizontal and vertical directions. Exponents of 0.71 and 0.02 were obtained for the horizontal and vertical directions for the medium grid, and 0.73 and -0.18 for the coarse grid. This gives a total of 100 images to process (20 fine grid, 40 medium grid and 40 coarse grid).

In addition to the grid blocks generated by this process, a layer of homogeneous grid blocks with huge pore volumes (25 x 10^{12} cubic feet) were added to the top and bottom of the reservoir to simulate a large gas cap and a large aquifer. All other data (also extracted from a real field study) are shown in the Appendix.

The single 2,000 ft horizontal well located nearly in the middle of the drainage volume is produced at a rate of 5,000 barrels per day with a minimum bottom-hole pressure of 1,500 psia. The results for oil production rate, GOR and WOR for the medium-f grid are shown in Figures 2 to 4. Based on these and other results, a single realization (identified on figures showing results as the base case) was selected for further study. Figure 5 compares production rates predicted for this base case by fine, medium-f, medium-p, coarse-f and coarse-p grids. Figures 6 and 7 provide corresponding results for GOR and WOR. Results of all of the simulations are summarized in Table 1. Here values of maximum, minimum, mean, and spread (maximum-minimum) are presented for:

1. Cumulative oil production during the plateau period (when the oil rate is constant at 5,000 barrels per day),
2. Time for the oil rate to drop to 3,000 barrels per day (40% of the specified rate),
3. GOR at 6,000 days,
4. WOR at 6,000 days. and
5. Bottomhole pressure at 2,000 days.

We have also performed simulations for the base case at the medium grid by using the upscaled geological description from the corresponding coarse grid. This was done to see the effect of grid block size (discretization errors). The results for this case are referred to as medium-f-c and they are compared with other cases on Figures 5 to 7.

These results show that the oil rate is more sensitive to upscaling than to gridblock
size. However, GOR and WOR are highly sensitive to both the block size and upscaling. This is confirmed by other work (not reported here) where we have found that cresting calculations require very fine grids. It is also clear that the geological description has a huge influence on results. In particular, we see that the spread in results decreases as reservoir parameters are upscaled to coarser and coarser grids, and power law averaging reduces the spread as compared to flow based upscaling. The spread in predictions based on just 20 stochastic images is huge and it is likely to increase as more images are processed. The other interesting observation is that a smaller spread does not necessarily mean lower uncertainty. In other words, the distribution of uncertainty generated by repeated flow simulations may not span the true or full uncertainty because of the assumptions made in the stochastic model and/or the method used for upscaling. In the example discussed here, the flow based upscaling (considered to be the more reliable method) gives a bigger spread in results than simpler power law averaging. Neither of the two upscaling methods is exact.

**Influence of Model Assumptions**

**Well Models**

All simulators use simplified models to relate the wellblock pressure to the pressure of the well in that block. Here we will show the effect of using an inappropriate well model. The sources of uncertainty in the well model are: saturation gradients that cause the effective phase permeabilities for the well region to be different from the corresponding values for the well grid block, effective absolute permeabilities for the well region may be different from the average values for the block, the effective block radius \( r_e \) may be in error because default procedures in simulators are based on assumptions that are more suitable for typical vertical wells than for horizontal wells, and the effective skin may not be known. All of these factors are not likely to cause the well index to increase or decrease by a factor of more than 5 times the default value. We have done simulations by changing the well index by a factor of 5, 0.2, 1.2 and 0.8. As expected the oil production rate, GOR and WOR are all highly sensitive to the WI. The effect of changes in WI on production rate and GOR for the base case medium-f grid are shown in Figure 8.

**Effect of Wellbore Pressure Drop on Well Performance**

Another factor in well modeling that is often ignored is the pressure drop in the well. This is only important in cases where the reservoir permeability is high and the drawdown is small. We have used a high pipe roughness of 1 mm in the medium-f grid base case to see the effect of well pressure drop on results. The pressure drop calculation method is the homogeneous (no-slip) model in the Eclipse (1995)* simulator. These two values of roughness cause a pressure drop in the well at 6,000 days that is approximately 18% of drawdown. The maximum reduction in oil rate is about 12% when friction is included over when friction is ignored. Clearly the effects of wellbore pressure drop are not as major a factor in this case as reservoir heterogeneities. The greatest effect of
wellbore pressure drop is on GOR. While in the homogeneous case the wellbore pressure drop causes the gas to breakthrough earlier than when this pressure drop is ignored, the behavior for the base case is opposite.

Analytical Cresting Models

Often analytical models are used to assess the tendency of water and gas to crest into a horizontal well. This is done because the simulation of cresting requires very fine grids. The analytical models are based on assumptions that are generally different from those in simulation studies. Also, analytical models can only produce critical rate or time for breakthrough, not the behavior for super-critical rates. Arbabi and Fayers (1995) have shown that different analytical models presented in the literature can produce results for critical rates that are different by a factor of 24. They have proposed a new model that produces essentially the same results as careful simulations that mimic the assumptions in the analytical model. Here we present an example where we have used the technique developed by Arbabi and Fayers (1995) to calculate the critical rate for our problem, under the assumption of steady-state, using average permeabilities of 433 mD in the horizontal direction and 14 mD in the vertical direction. The optimum well location, defined as the location that gives the same critical rate for both the gas and water interfaces, is predicted to be about 30 ft from the gas/oil contact with a critical oil rate of about 68 barrels per day. Theory shows that for the no-flow boundaries used in simulation, there is no critical rate. Simulations with a rate of 50 barrels per day (critical rate of the well in the middle of the reservoir) show that indeed this is true, but the gas and water breakthroughs occur after 3,000 years for the “optimum” well location, and when the well is located in the middle of the reservoir water breakthrough occurs at about 1,800 years and gas at about 4,300 years. As expected, when the simulations are done with the medium-f grid, breakthroughs occur earlier. We have also done simulations with the production rate of 5,000 barrels per day and the two well locations. Again, as expected, moving the well to the 30 ft location delays water breakthrough and reduces gas breakthrough times. The overall conclusion from this part of our work is that critical cresting rate solutions available in the literature have little practical utility, because economical production rates are normally much higher than critical rates.

Productivity Models

The most common approach used to compare the performance of horizontal and vertical wells is the use of single phase analytical solutions for steady-state or pseudo steady-state flow in homogeneous media. The most popular of these is Joshi’s equation. Here we will compare results of this equation with simulator predictions. Since the simulations reach approximately a pseudo steady-state behavior at a time of approximately 6,000 days, we will compare results from Joshi’s equation with simulations at this point. For the medium-f grid and the base case description, the drawdown (difference in the initial pressure at the well and the current well pressure) is around 811 psia. The calculated production rate from Joshi’s equation for this drawdown is 15,280 barrels per day. This is more than eight times the rate predicted by
the simulator for the base case at the same time. (The drawdown is about 800 psia if it is based on the average reservoir pressure at 6,000 days, not enough to make any significant difference in the results.) The spread in rates at 6,000 days from all twenty medium-f simulations is from about 1,800 to 5,000 barrels per day. Again these results show the inappropriateness of using steady-state analytical models for predicting horizontal well performance.

References


Appendix—Rock and Fluid Properties

Rock and fluid properties used (Table A-1) are extracted from a real field case study of a North Sea reservoir.

<table>
<thead>
<tr>
<th>Table A-1—Summary of Rock and Fluid Properties Used</th>
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<tbody>
<tr>
<td>Initial pressure, $P_i$, at GOC</td>
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<tr>
<td>Rock compressibility, at $P_i$</td>
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<tr>
<td>Oil viscosity</td>
</tr>
<tr>
<td>Gas viscosity</td>
</tr>
<tr>
<td>Connate water saturation</td>
</tr>
<tr>
<td>Critical gas saturation</td>
</tr>
<tr>
<td>Residual oil sat. to water</td>
</tr>
<tr>
<td>Residual oil sat. to oil</td>
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<tr>
<td>Capillary pressure</td>
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Table 1—Summary of Simulation Results

<table>
<thead>
<tr>
<th></th>
<th>Cumulative Oil Production (plateau period) MMSTB</th>
<th>Time to Reach Oil Rate of 3,000 STB/Day Days</th>
<th>GOR at 6000 Days MSCF/Day</th>
<th>WOR at 6000 Days</th>
<th>WBHP at 2000 Days Psia</th>
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<tbody>
<tr>
<td>Minimum</td>
<td>7.40</td>
<td>3753</td>
<td>74</td>
<td>0.89</td>
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<td>Mean</td>
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<td>5973</td>
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<td>6.55</td>
<td>609</td>
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<td>Maximum</td>
<td>34.35</td>
<td>9706</td>
<td>426</td>
<td>8.23</td>
<td>2159</td>
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<tr>
<td>Minimum</td>
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<tr>
<td>Maximum</td>
<td>22.97</td>
<td>7565</td>
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<td>Spread</td>
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<td>302</td>
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<tr>
<td>Maximum</td>
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<td>8275</td>
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<td>5674</td>
<td>634</td>
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<td>818</td>
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Coarse Grid flow based

Medium Grid flow based

Coarse Grid power averaged

Medium Grid power averaged
Fig. 1—Histograms of horizontal and vertical permeability for fine, medium, and coarse resolutions. A fixed multiplier of 0.1 is applied to the vertical permeability data in the simulations.
Oil Production Rate vs Time
20 Realizations on Medium Grid

Fig. 2—Oil production rate for 20 realizations on Medium-f grid. ■ is realization 19 which is the base case.

GOR vs Time
20 Realizations on Medium Grid

Fig. 3—Gas/Oil ratio (GOR) for 20 realizations on Medium-f grid. ■ is realization 19 which is the base case.
Fig. 4—Water/Oil ratio (WOR) for 20 realizations on Medium-f grid. ■ is realization 19 which is the base case.

Fig. 5—Comparison of oil production rates from different grids for the base case (realization 19)
Fig. 6—Comparison of gas/oil ratio (GOR) from different grids for the base case (realization 19)

Fig. 7—Comparison of water/oil ratio (WOR) from different grids for the base case (realization 19)
Oil Rate and GOR vs Time
Effect of Variation in Well Index

Fig. 8—Effect of well index (WI) on oil production rate and GOR for the base case (realization 19)

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