**Horizontal Well Testing in India**

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Flow regimes of a horizontal well: (a) early-time pseudoradial flow around borehole in the y-z plane; (b) intermediate-time linear flow in the y direction caused by pressure transient reaching reservoir boundaries; (c) late-time pseudoradial flow in the x-y plane.

The continued success of horizontal drilling has emphasized the need for test interpretation models tailored to horizontal wells. Schlumberger researchers have developed an analytical model for the pressure response and flow regimes during testing of the horizontal well in nonfractured formation. The model has been incorporated into the Schlumberger Transient Analysis and Report (STAR*) program, part of a computer-based reservoir analysis system. Using the STAR program, reservoir engineers recently interpreted pressure transient tests for the Oil and Natural Gas Commission (ONGC) in the Bombay High field, offshore India.

**Horizontal Flow Regimes**

In a horizontal well allowed to produce after shut-in, three flow regimes will normally occur. Flow is first radial (normally elliptical because of permeability anisotropy) around the wellbore in the y-z plane, hence the term early-time pseudo-radial flow (left). This is the only regime in which the true skin can be measured. Wellbore storage effects, which are increased by surface shut-in and can only be accounted for by measuring downhole flow rates, can obscure this regime.

Next, if the well is long compared to the reservoir thickness, intermediate-time linear flow parallel to the y-axis develops as the pressure transient reaches the reservoir.

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* Mark of Schlumberger
Diagnosis of flow regimes during a horizontal well test from a log-log plot of the normalized pressure and pressure derivative versus elapsed time. Wellbore storage is more prominent in horizontal than vertical well testing because more fluid exists in the wellbore below the tool. It can mask the early-time pseudo-radial flow, particularly if downhole flow rates are not available to account for it.

Vertical flow will not develop in wells with pressure maintained by a gas cap or an aquifer. The third regime—late-time pseudo-radial flow—also involves radial flow around the well, but in the bedding (x-y) plane. This period may not develop if the horizontal width of the reservoir is not much greater than the well length or if reservoir pressure is maintained by a gas cap or aquifer.

Horizontal well test interpretation is more complex than its vertical counterpart. In a vertical well, radial flow is easier to identify because it occurs after wellbore storage effects become negligible and before boundary effects are seen. Pseudo-radial flow free from these effects does not last as long as in horizontal wells because they exhibit spherical flow at the ends of the well. Furthermore, in a horizontal well, fluid flow near the wellbore is influenced by permeabilities perpendicular as well as parallel to the depositional structure. Consequently, vertical variations in permeability and shale distribution affect the pressure and flow rate responses. One benefit of a horizontal well is that a properly designed test with downhole flow rate measurements can yield anisotropic permeability components, \( k_x \), \( k_y \), and \( k_z \).

As with a vertical well test, initial estimates of the major formation properties from a horizontal well test—permeability, skin, and pressure—may be determined from radial (and sometimes linear) flow regimes identified on log-log plots of normalized pressure and its derivative with respect to the superposition time function (above). If downhole flow rates are measured, then the normalized pressure and its derivative with respect to the sandface rate convolved time function are plotted instead. Pseudo-radial flow yields a zero slope on the pressure derivative plot. Effective permeability measured in early-time pseudo-radial flow is \( \sqrt[3]{k_x k_y} \) and in late-time pseudo-radial flow is \( \sqrt[3]{k_y k_z} \). Intermediate-time linear flow yields a slope of \( \frac{1}{2} \) on the pressure derivative and gives an effective permeability of \( k_x \).

The key to a successful horizontal well test interpretation is identifying the early-time pseudo-radial flow. Skin caused by wellbore damage can be more accurately obtained from this regime than from the late-time pseudo-radial regime. At late-time, the apparent skin has two contributions: one from wellbore damage and an additional pressure drop, called the geometrical skin, because the flow pattern near the well differs from the radial one far away in the horizontal plane. This geometrical skin, which usually dominates, depends on the anisotropic permeabilities that are not known precisely. Also, only the early-time pseudo-radial flow regime is affected by the vertical permeability, \( k_z \). If the early-time period is missed, \( k_z \) cannot be determined.

Testing the Bombay High
In testing NR-1H, one of two ONGC experimental Bombay High wells, ONGC was especially interested in the permeability anisotropy ratio (see "Reservoir Parameters of Horizontal Well NR-1H," below). The

<table>
<thead>
<tr>
<th>Reservoir Parameters of Horizontal Well NR-1H</th>
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<tbody>
<tr>
<td>Length of perforated interval, ft</td>
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<tr>
<td>Formation thickness, ft</td>
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<td>Distance to no-flow boundary, ft</td>
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<td>Wellbore radius, ft</td>
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<tr>
<td>Porosity</td>
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<tr>
<td>Total compressibility, psi⁻¹</td>
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<td>Fluid viscosity, cp</td>
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well was completed with cemented casing and tubing-conveyed perforation. It then underwent a matrix acid job, standard practice for wells in this limestone formation. Next, a series of alternating drawdown and buildup tests was performed using a Production Logging (PLT) tool equipped with flowmeter and temperature and pressure gauges (left). Downhole flow measurements were crucial for identifying the early-time pseudo-radial flow regime.

Of the post-acid pressure transients, drawdowns 5, 6, and 7 and buildup 6 lasted long enough to yield significant information. STAR generated log-log plots of the pressure and its derivative for these tests revealed strong cleanup effects from acidizing. On drawdowns 5 and 6, eliminating them from further analysis. The remaining transients were replotted on log-log plots of the pressure and its derivative with respect to the superposition time function and the pressure derivative with respect to the sandface convolution time function. The combined plot for buildup 6 and drawdown 7 illustrates the consistency of the data from one transient to the next (left). Two plateaus in the derivative curve appear, indicating pseudo-radial flow but at different times. The early-time pseudo-radial flow shows up more clearly in the drawdown 7 data while the late-time pseudo-radial flow regime appears only during buildup 6, which lasted longer. Derivative curves for both transients show the slope of $1/3$, characteristic of intermediate-time linear flow. The effective permeabilities—$\sqrt[3]{k_x \alpha}$ and $\sqrt[3]{k_y \alpha}$ for the early and late-time pseudo-radial flows, and $k_y$ for the intermediate-time line flow permeability, respectively—were calculated from the slopes of the sandface convolution plots (see “Buildup 6 and Drawdown 7 Estimates,” below left).

So far, only particular flow regimes had been used to provide initial estimates of reservoir parameters. To refine these estimates, reservoir engineers use a full-scale simulation combining all data for one test or several tests. The initial estimates of permeability and skin were put into the analytical model, which then simulated (or history matched) the measured flow rates from the well tests with the measured pressures as input and vice versa. Reservoir engineers used the STAR system to determine the set of reservoir parameters that optimized the match between measured and simulated data (see “Parameters of the STAR System,” next page, below left). Flow rate simulations based on pressure measurements may be preferred if there are periods of unmeasured flow rate during a test sequence. These

### Buildup 6 and Drawdown 7 Estimates

<table>
<thead>
<tr>
<th></th>
<th>BU6 intermediate-time linear flow</th>
<th>BU6 late-time pseudo-radial flow</th>
<th>DD7 early-time pseudo-radial flow</th>
<th>DD7 middle-time linear flow</th>
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</thead>
<tbody>
<tr>
<td>$k_x$, md</td>
<td>45.83</td>
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<td>-3.18</td>
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occur when the flow rate falls below the spinner threshold or debris jams the spinner. Pressure measurements, however, are usually available for the entire test period.

Buildup 6 and drawdown 7 were each history matched using a model of the reservoir with horizontal permeability anisotropy (see “Estimates of Simulation from Anisotropic Permeability Model,” below, right). Excellent reproductions of observed transient behavior can be seen on the history matches based on measured flow rates for drawdown 7 and based on measured pressure and its derivative for buildup 6 (right).

In general, good agreement exists between the reservoir parameters obtained from the history match of the two transients. The estimates of $k_x$ differ significantly. The higher $k_x$ value obtained from the drawdown is considered more reliable because the flow rates measurements during the intermediate-time of buildup were noisy. This was due to flow rates approaching and then falling below the spinner threshold.

The ability to successfully interpret horizontal well tests has played an important role in ONGC’s ongoing development of the Bombay High field. Two additional horizontal wells have been drilled since this initial testing and plans for an expanded drilling program are underway.

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**Parameters of the STAR System**

The STAR module for horizontal wells allows reservoir engineers to estimate any combination of the following parameters:

- horizontal permeabilities, assuming either horizontal isotropy ($k_x = k_y$) or horizontal anisotropy.
- vertical permeability, $k_z$
- skin: this refers to a pressure drop at the wellbore face caused by a change in flow at the well. Early-time pseudo-radial flow is more indicative of formation damage than skin from late-time pseudo-radial flow.
- wellbore storage coefficient: this accounts for compression and expansion effects of the fluid volume existing in the wellbore below the flowmeter.
- distance of wellbore from layer boundary; this parameter is sometimes not known a priori, since horizontal wells snake up and down in the formation.

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**Estimates of Simulation from Anisotropic Permeability Model**

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<tr>
<th>Transient</th>
<th>$k_x$, md</th>
<th>$k_y$, md</th>
<th>$k_z$, md</th>
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</thead>
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<tr>
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<td>10.4</td>
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<tr>
<td>Drawdown 7</td>
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<td>19.3</td>
<td>1.6</td>
<td>-2.3</td>
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