

# Production Operations



**Bob Poe**, SPE, Engineering Adviser, Schlumberger Data and Consulting Services, has more than 20 years' experience in well completions and production operations. Most of his career has been spent in well-stimulation design and evaluation, production-performance evaluation, phase behavior, and reservoir simulation. Poe holds BS, ME, and PhD degrees in petroleum engineering from Texas A&M University. He has authored numerous SPE papers on production-performance analyses and has served on several SPE workshop and conference organizational committees and a Reprint Series Committee. Poe currently serves on the JPT Editorial Committee.

Welcome to the Production Operations feature. Practicing production-operations engineers may employ a wide variety of technologies in their work, and several of these technologies are highlighted in this feature. Some of the commonly used technologies are the analysis of the production performance of oil or gas wells, methods for identification and remediation of water-production issues, fluid-inflow-control design, and actions in a horizontal or complex multibranch wellbore. In each case, reliable and accurate characterization of the productive formation and the well-completion properties is fundamentally required.

This issue includes summaries of some excellent research efforts and field-application results in the evaluation of well performance in low-permeability and complex reservoirs. Reservoir complexities addressed in the selected technical articles include the practical reservoir- and production-engineering aspects of stress-sensitive formations, composite and multilayer formations, single- and dual-porosity reservoirs, fracture cleanup and/or damage with respect to production time, and the very common effect of wellbore liquid loading. Specific issues that pertain to the evaluation of fractured and horizontal wells are addressed in the selected technical papers, including the design and application of inflow-control devices to enhance the production of horizontal-well completions.

In addition to the cited articles, some extremely valuable developments and insight are available in the additional reading references. The research presented in these articles includes the tomographic evaluation of skin-damage evolution in unconsolidated sandstones and the control and remediation of water production in stratified and low-permeability gas reservoirs. Each of these issues is also extremely important in production operations.

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**Production Operations additional reading available at the SPE eLibrary: [www.spe.org](http://www.spe.org)**

**SPE 107832** • "Study of Skin Damage in Unconsolidated Sandstone by Computed Tomography" by E.S. Sales, COPPE/UFRJ, et al.

**SPE 106640** • "Optimum Control of Unwanted Water Production in Stratified Gas Reservoirs" by Nampetch Yamali, SPE, University of Texas at Austin, et al.

**SPE 105262** • "Successful Innovative Water-Shutoff Operations in Low-Permeability Gas Wells" by Hassan Chaabouni, SPE, Schlumberger, et al.

# Effect of Complex Reservoir Geometries and Completion Practices on Production Analysis

Complex reservoir geometries can influence the results obtained from transient-production-decline analysis. For tight gas reservoirs, it is common to observe limited drainage areas and linear-flow geometries. In some cases, these results are inconsistent with the expected geological, structural, and depositional character of the reservoir. Complex reservoir geometries and flow conditions such as liquid loading can contribute to this phenomenon. Numerical-simulation cases will be used to generate the control data sets to demonstrate these effects. The full-length paper presents seven cases showing the effects of complicated reservoir flow conditions on the results obtained from production analysis.

## Introduction

Production analysis commonly is used to evaluate completion efficiency and effective drainage area of producing wells. The technique is a type-curve-matching technique. Flowing bottomhole pressures and production rates are treated as a long-term production/drawdown test, providing an estimate of effective drainage area, flow capacity, and effective fracture half-length through type-curve analysis. This technique, applicable for both oil and gas producers, originally was presented for a single-layer reser-

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 111285, "Evaluation of the Effect of Complex Reservoir Geometries and Completion Practices on Production Analysis," by S.A. Cox, SPE, R.P. Sutton, SPE, and R.P. Stolz, SPE, Marathon Oil Co.; R.D. Barree, SPE, Barree & Assocs.; and M.W. Conway, SPE, Stim-Lab, prepared for the 2007 SPE Eastern Regional Meeting, Lexington, Kentucky, 17–19 October. The paper has not been peer reviewed.*

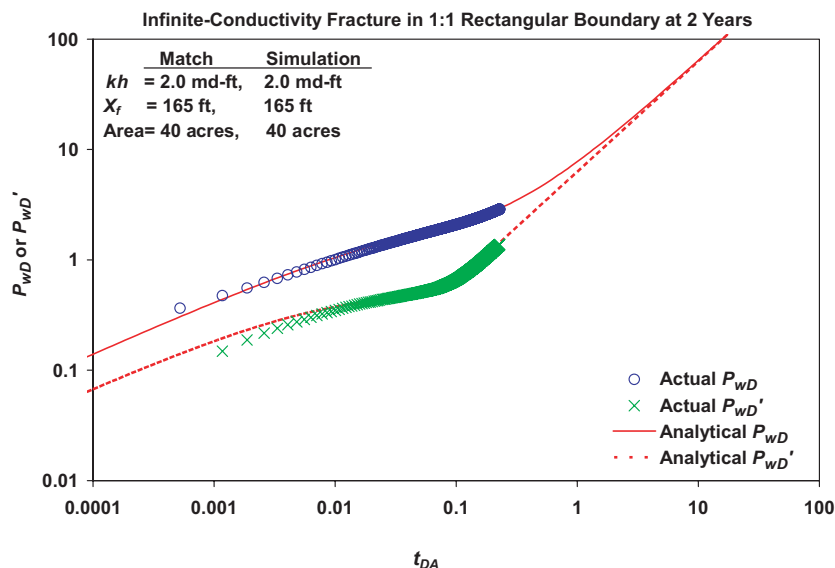


Fig. 1—Base-case production-analysis results.

voir. The technique is applied to layered systems by assuming average properties for the productive zones.

Production-analysis techniques are well suited for the analysis of tight gas reservoirs. Tight gas reservoirs typically stay in transient flow for an extended period of time, and therefore daily pressure and rate data can be used to analyze the transient behavior of the reservoir around the producer. Tight gas wells typically drain a limited area and often experience linear flow for an extended period of time after completion.

## Simulation

Numerical-simulation cases were constructed to develop production and pressure profiles used for the analysis. The base case for this analysis was a fracture-stimulated radial-flow model. The reservoir geometry for the single-layer cases was a square, and for the multilayer case, the top layer was a high-permeability channel. Production rate from the models was controlled by

a 350-psi constant tubing pressure with a 10,000-Mscf/D maximum rate limit. The base case was run for 2 years.

## Base Case

The base case represents a well producing from the center of a 40-acre square reservoir. The results of this case demonstrate the ability of the production-analysis technique to match simulation results. Fig. 1 is the type-curve match for this case. It should be noted that the match assumes an infinite-conductivity fracture and that an acceptable match also was obtained by use of a finite-conductivity model with a 200-ft fracture half-length,  $X_f$ , and a 75-md-ft fracture conductivity. Logarithmic gridding was used in the simulation cases to capture the transient flow in the reservoir and eliminate numerical dispersion.

## Case 1

This case incorporates stress-dependent permeability into the base case. In this case, as the cell-block pressure

For a limited time, the full-length paper is available free to SPE members at [www.spe.org/jpt](http://www.spe.org/jpt).



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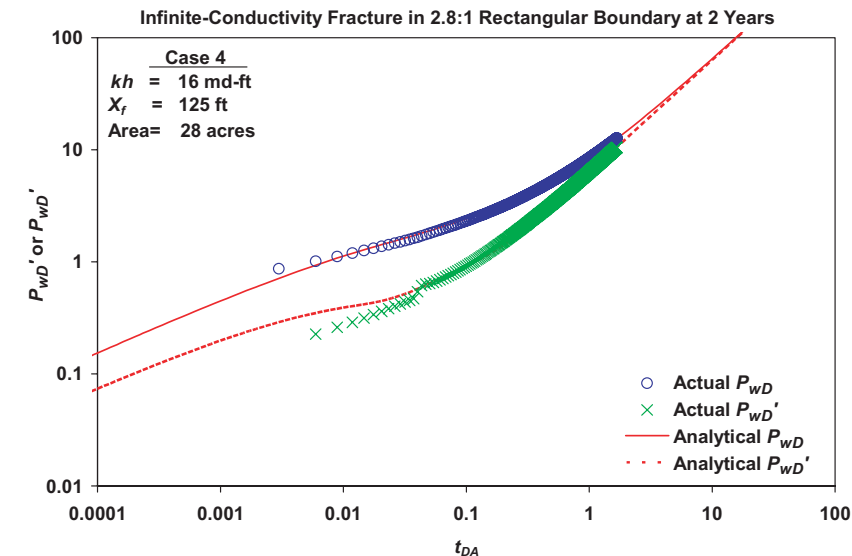
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is reduced, the effective permeability is reduced as a function of increasing stress. The stress-vs.-permeability data used for this case were obtained through laboratory experiments and are typical for stress-sensitive reservoirs.

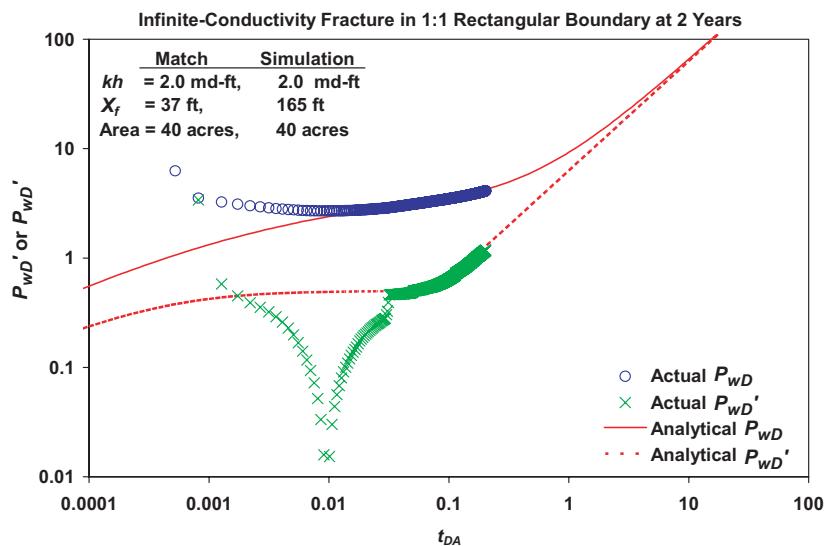
The effect of increasing stress on the reservoir flow capacity, effective  $X_f$ , flow geometry, and effective drainage area was examined through production analysis. When a well is placed on production in this type of environment, the reservoir flow capacity decreases as pressure depletes in the reservoir, resulting in an increase in net stress in the reservoir rock. At first, only the near-well region is affected by the pressure decrease. As the drainage area increases with time, there is a corresponding decrease in pressure within the drainage area. Because of the nature of the rock, there is a corresponding decrease in permeability. This is typically noted as a decrease in flow capacity over time. The effect is not a result of a change in the flow geometry within the reservoir. The effect, when modeled using production-analysis results, is a longer effective  $X_f$  as a result of the initial improvement in the dimensionless fracture conductivity. As expected, the overall flow capacity was reduced in the reservoir, and the effective drainage was less for the same 2-year production life. After 30 years of production, the apparent drainage area obtained from the analysis increased to 34 acres. The stress-dependent nature of this reservoir results in a false depletion stem. In this case, production analysis did show the reduced reservoir flow capacity and did not suggest that a reduced fracture length caused the reduced production rate.

#### Case 4

This case is a two-layer reservoir with the top layer having a 20-md-ft flow capacity producing from a 466-ft-wide by 1,320-ft-long channel. The drainage area of the upper layer is 14 acres, with a 2.8 length-to-width ratio. The bottom layer has properties identical to the base case, with 2.0-md-ft flow capacity, a 40-acre drainage area, and a 1.0 length-to-width ratio. Both layers have a 200-ft-gridded fracture with a 75-md-ft fracture conductivity. **Fig. 2** shows the type-curve match for this case. After 2 years of production, the match clearly shows that the reservoir flow geometry is dominated by the high-permeability upper zone. A second model was constructed



**Fig. 2—Case-4 production-analysis results.**



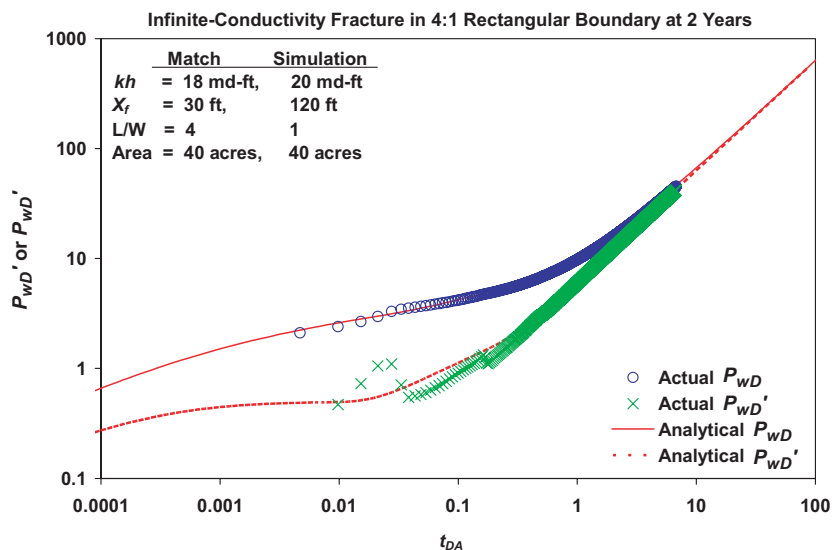
**Fig. 3—Case-5 production-analysis results.**

with the channel having a 2.0-md-ft flow capacity and the bottom zone having the higher flow capacity. In this case, the type-curve match was obtained with an 1.0 aspect ratio and a 27-acre effective drainage area. The low effective drainage area for these cases is a result of treating the two-layer channel/blanket sand as a single zone with an 80-ft net thickness (model net pay at the completion). When the actual geometry is not known, assuming a common geometry for both sands results in an inaccurate estimate of drainage area. However, the resulting drainage-volume estimate obtained from the analysis matches the simulated volume. The actual reservoir geometry can be determined if the indi-

vidual-zone rates are known through time. It has been shown that in some cases, treating noncommingled zones as a single sand with average properties can extend the time to reach pseudosteady state significantly.

#### Case 5

Case 5 focuses on hydraulic-fracture cleanup. The base model was used for this case, and the cleanup time in the simulation was 60 days. The conductivity of the fracture was set equal to the formation conductivity at Day 1. Hydraulic-fracture cleanup has a distinct type-curve response. **Fig. 3** is the type-curve match for this case. Note the negative slope in the early-time data and the fact that the



**Fig. 4—Case-7b production-analysis results.**

resulting match shows much less effective  $X_f$  than the base case.

This result may be one of the most logical explanations for the short fracture lengths obtained from production analysis. After stimulation of a gas well with a liquid fracturing fluid, the conductivity and effective fracture length with respect to gas is zero. Gas-saturated fracture length increases with improving conductivity as desaturation occurs during cleanup. The fracture length estimated depends entirely on the degree of cleanup accomplished at the time when the flow is observed, and in this case, at dimensionless time based on area,  $t_{DA}$ , of approximately 0.04 (after 69 days of production). It is important to note that the fracture conductivity after 60 days was equal to the base-case conductivity of 75 md-ft.

### Case 7

This case presents the results of liquid loading. In tight gas reservoirs, liquid loading historically has been viewed as a mechanical problem that effectively is placing an additional backpressure on the formation. However, experience has suggested that liquid-loading results in a false depletion stem in production type-curve analysis. This work set out to address the cause of this phenomenon. This study approached the problem in a stepwise fashion. The first step was to determine if ignoring the additional backpressure caused by the liquid standing over the perforations would cause an early depletion stem. The second step was to incorpo-

rate the effects of spontaneous imbibition during flowing conditions into the model. This process was approximated by allowing small amounts of water to drop out during production. Effectively, the near-wellbore region has slightly increasing water saturation with time during production. In conjunction with this study, laboratory experiments were conducted to determine if the process could be modeled physically. The results of the laboratory experiments showed that if water was allowed to stand in or above the perforations, the effective gas permeability was reduced by as much as 75% of its original value. These results were transformed into a relative permeability curve that was used in the simulation runs modeling this effect.

Case 7a assumes a static liquid column is present but not accounted for when calculating flowing bottomhole pressure for the analysis. This case shows that backpressure alone does not account for field observations. The reservoir flow capacity and the effective  $X_f$  are less than the actual values in the simulator because the incorrect bottomhole flowing pressure is accounted for as reduced completion efficiency. However, the effective drainage area and shape are correct.

Case 7b assumes a static liquid column is present causing imbibition during the production life of the well. Liquid fills the near-wellbore fracture and matrix. **Fig. 4** presents the type-curve match for this case, where the relative permeability in both the hydraulic

fracture and the matrix are affected. The actual flowing bottomhole pressures were used in the analysis of this case. Note the geometry changed from radial flow in the base case to a 4:1 rectangle. The drainage volume remains at 40 acres. Most of the effect is reflected in reduced fracture efficiency and an elongated reservoir shape, which means that the production analysis did not identify properly the cause of the poor performance.

Case 7c also examines the effect of the damage caused by imbibition. However, in this case, the standing liquid column was assumed to develop in late time during boundary-dominated flow. The apparent area is reduced from the actual area of 40 acres to 29 acres for the match.

### Summary

The production-analysis technique presented in the full-length paper represents a powerful technique that can be used by the reservoir engineer to determine well spacing and forecast future performance. The technique also can be used by the production engineer to evaluate completion efficiency and to identify potential problems associated with well performance. This approach requires that the reservoir and fracture are producing at a constant, steady-state condition over the time frame of the analysis. When this is the case, as was shown for the base case, the analysis returns the conditions used in the numerical simulator. If these conditions are not achieved, then the production-analysis technique cannot be expected to provide a unique solution.

The majority of the cases presented in the full-length paper addressed flow conditions where either the reservoir or fracture flow capacity was changing with time. When any of the flow properties are decreasing with time, the reduced late-time production rate is accounted for by production history matches with a reduced reservoir size and, in some cases, with an indication of linear-flow behavior.

### Nomenclature

- $h$  = reservoir thickness, ft
- $k$  = effective permeability, md
- $p_{wD}$  = dimensionless wellbore pressure
- $t_{DA}$  = dimensionless time based on area
- $x_f$  = fracture half-length, ft

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## Analysis of Production Data From Hydraulically Fractured Horizontal Wells

The full-length paper discusses the analysis of production data from hydraulically fractured horizontal wells in tight, heterogeneous formations. Horizontal wells with longitudinal and transverse hydraulic fractures that might be surrounded by a region with natural fractures are considered. These well/reservoir configurations are of interest in many unconventional reservoirs, including tight gas sands and shale-oil or -gas formations. A semi-analytical model that incorporates the key features of reservoir heterogeneity and the details of hydraulic-fracture and wellbore flow was used to compute production decline.

### Introduction

In the last decade, interest in developing unconventional oil and gas reservoirs has grown. Most of these unconventional reservoirs have very low permeability, as in the case of tight gas sands and fractured shale formations. Production economics for these reservoirs normally requires large reservoir contact per well. An efficient means of increasing reservoir contact to achieve higher well productivity is to drill horizontal wells and stimulate with hydraulic fractures. Productivity might be improved further if the horizontal well and hydraulic fractures are

connected to an active natural-fracture network. This fracture network may be pre-existing in a naturally fractured reservoir (dual-porosity system) or may be generated or reactivated locally by hydraulic fracturing around the well. Production characteristics of wells in globally and locally fractured reservoirs may differ significantly, depending on the contrast between the matrix and natural-fracture properties.

The full-length paper discusses the analysis of production data from hydraulically fractured horizontal wells in reservoirs with a global- or localized-natural-fracture network. It explains the characteristics of production decline associated with various transient-flow regimes, describes the procedure to generate production-decline curves, and demonstrates matching field data with the model. The general idea of this work follows from a production-decline-analysis concept. A transient productivity index (PI),  $J$ , is used in the analysis of production data for horizontal wells. Material-balance time is incorporated into the analysis to generalize the analysis procedure for all phases and modes of production.

There are two important aspects of the approach presented in the full-length paper. The first aspect is the use of a semianalytical model that incorporates the important features of reservoir heterogeneity and hydraulic fractures without elaborate numerical computations. The model was built on the basis of a semianalytical simulation approach. Having a computationally efficient model is important in that the production-decline model needs to be used in an iterative manner in the analysis of the field production data. Moreover, especially in the early development stage, there are not enough

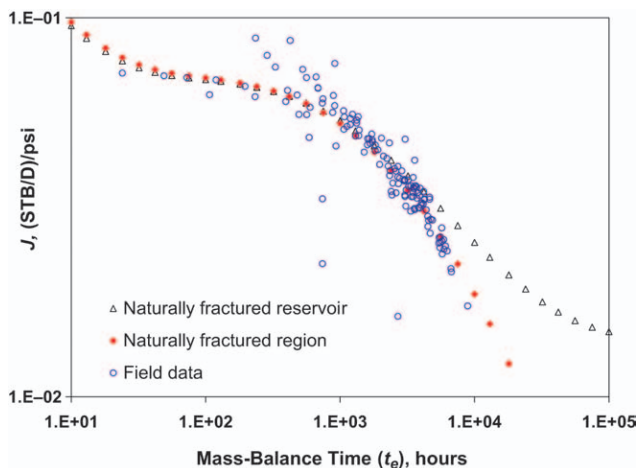
data to sufficiently characterize heterogeneous, unconventional reservoirs. Therefore, more-detailed numerical modeling may not be a viable option until more data become available later in the development of the field.

The second important feature of this approach is the use of the transient PI in the analysis of production data. Most of the productive life of fractured horizontal wells in tight, homogeneous or naturally fractured formations might be under transient-flow regimes. In such formations, flow rates may demonstrate transient decline characteristics for several decades and may become uneconomical by the time stabilized flow is reached. Especially in formations where fractured horizontal wells are more efficient, this behavior should be expected because the improvement of productivity by horizontal and fractured horizontal wells is by accelerated production during transient flow. Use of the transient PI concept helps production data analysis for fractured horizontal wells by emphasizing the characteristics of production decline during transient-flow periods.

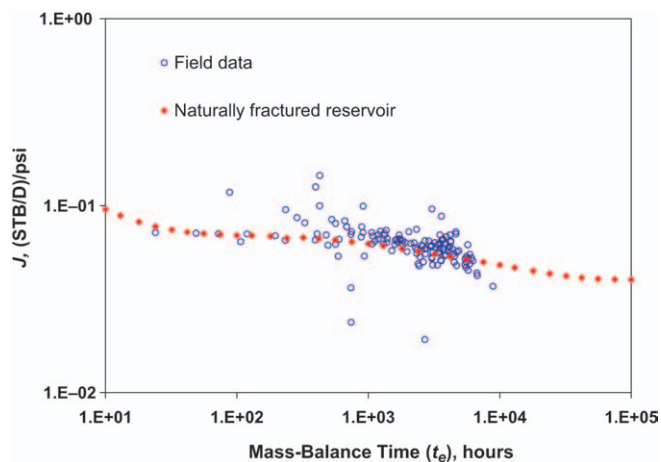
Unlike decline curves for vertical wells, which have one flow regime during transient flow, fractured horizontal wells display several well-defined flow regimes with distinct rate-decline characteristics during transient flow. Matching the transient production data of fractured horizontal wells over multiple flow periods improves confidence in the transient rate-decline analysis. In addition, use of the transient PI is consistent with the conventional pressure-transient theory. In unconventional reservoirs, project economics usually restricts pressure-transient-data acquisition through well testing. Therefore, use should be made of the production data

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 110848, "Analysis of Production Data From Hydraulically Fractured Horizontal Wells in Tight, Heterogeneous Formations," by F. Medeiros, SPE, Petrobras, and B. Kurtoglu, SPE, E. Ozkan, SPE, and H. Kazemi, SPE, Colorado School of Mines, prepared for the 2007 SPE Annual Technical Conference and Exhibition, Anaheim, California, 11–14 November. The paper has not been peer reviewed.*

For a limited time, the full-length paper is available free to SPE members at [www.spe.org/jpt](http://www.spe.org/jpt).



**Fig. 1—PI match for a large reservoir block.**



**Fig. 2—PI match for a small reservoir block.**

[surface flow rate and wellhead pressure (WHP)] to analyze well productivity and obtain some key parameters of well and reservoir performance.

### Semianalytical, Heterogeneous-Reservoir Model

The semianalytical model used in this work computes pressure or pseudo-pressure responses for heterogeneous liquid or gas reservoirs, respectively. The computational algorithm of the model is a version of the boundary-element method based on the Green's function solution for the diffusivity equation in bounded, homogeneous porous media. Heterogeneities are incorporated into the model by considering a reservoir that consists of regions (blocks) of different properties. Within each region, properties are uniform and correspond to the local averages. The blocks are coupled by assuming pressure (pseudopressure for gas) and flux continuity at block interfaces.

The semianalytical model is applied to obtain characteristics of pressure and pressure-derivative responses for a horizontal well with hydraulic fractures (longitudinal or transverse), which can be surrounded by a region of natural fractures. Although the model can incorporate the effect of wellbore hydraulics, this work treats horizontal wellbores as line sources with infinite conductivity. Hydraulic fractures are modeled as porous media (fracture medium can be composed of single or multiple blocks to account for appropriate flow regimes and fracture heterogeneity). Regions with natural fractures are modeled by use

of a dual-porosity idealization. Dual-porosity parameters are incorporated in the semianalytical model.

Calibration of the semianalytical model is accomplished by matching the results with field production data. The calibration process involves two crucial steps. The first step is identification of flow regimes from the field data. To be able to capture the characteristics of some transient rate-decline periods, the computational grid may need to be adjusted to capture the expected flow geometry. (The computational advantage of the semianalytical simulation approach over full finite-difference simulation is that gridding is required only at the interfaces of the blocks. No computational grid is required within the reservoir blocks.) The second step of the calibration process involves matching the actual production data by adjusting reservoir, hydraulic-fracture, and natural-fracture properties. Use of available data, such as core analysis, well logs, hydraulic-fracture design, pressure-transient data, and geologic model, guides the calibration process and reduces nonuniqueness problems. When a reasonable match is achieved, unknown reservoir properties and drainage volume are inferred and the semianalytical model is used to forecast well production.

### Transient PI

Use of material-balance time (or material-balance pseudotime) makes transient PI a weak function of the production mode. Therefore, the transient PI for the field data plotted against equivalent time can be

correlated with the transient PI for constant-rate production. This eliminates the requirement to construct more-complex, variable-rate (superposition) solutions for the analysis of production data. This approach also unifies and simplifies the diagnostics used in the interpretation of transient-PI vs. time curves.

Because the model transient PIs can be computed for constant-rate production, the definitions given by Eqs. 3 and 9 in the full-length paper provide a convenient means of computing transient PI.

### Application Examples

The full-length paper presents the analysis of oil production from two hydraulically fractured horizontal wells that have 9,000-ft horizontal sections in a tight-shale formation. For both wells, multistage hydraulic-fracture design was intended to create longitudinal fractures, and tracer logs verified the longitudinal orientation of the fractures. In the analysis of the production data, it is assumed that the horizontal well in both cases is at the center of a 10,200×4,000×30-ft reservoir block. Other properties of the reservoir and Well A are presented in Table 4 in the full-length paper.

**Well A.** The analysis begins by computing the bottomhole pressure (BHP) from WHP measurements. The BHP and surface flow-rate data are plotted against time. Although this graph shows a sharp production decline, pressure/volume/temperature data and gas/oil-ratio analysis indicate that BHP is above the bubblepoint for all

times. Thus, the analysis procedure for a single-phase liquid can be used.

The circular data points in **Fig. 1** show the transient PI computed from the field data. In these computations, the total volume of the reservoir block was used ( $1.2 \times 10^9$  ft<sup>3</sup>). Because the PI curve does not flatten at late times, it is assumed that the production is under transient conditions for all times. The triangular data points in **Fig. 1** show the best match of the field data by use of a dual-porosity reservoir model (a globally fractured reservoir model). The comparison between the field and model transient PIs demonstrates a good match at early times, but the model results deviate from the field data after 3,200 hours (133 days). The faster decline of the productivity of the actual reservoir indicates that the permeability might be lower than that assumed in the model, or the natural fractures are limited to a smaller region around the well.

The transient PI represented by diamonds in **Fig. 1** corresponds to a model

with a limited dual-porosity region around the well. **Fig. 14** in the full-length paper presents a sketch of this well/reservoir system. As shown in **Fig. 1**, there is a fair agreement between the field and model transient PIs for this case. Because of the slower drainage of the external, tight homogeneous matrix, transient flow lasts a long time and *J* displays a long continuous decline before reaching a constant value during boundary-dominated flow.

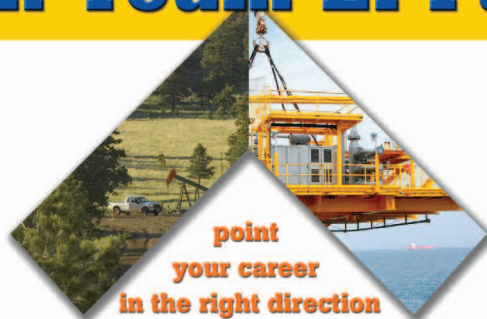
To explore the possibility that the tight external matrix beyond the naturally fractured region might not contribute significantly to productivity, transient PIs were computed assuming a reservoir volume equal to the volume of the naturally fractured region shown in **Fig. 14**. Transient PIs computed from the field data and this model are shown in **Fig. 2** by the circular and diamond markers, respectively. (Reservoir parameters obtained from the match in **Fig. 1** were used for the model.) The transient PI for this reservoir volume displays a smooth decline

and a trend to flatten quickly. This is a result of the efficient drainage of the smaller reservoir. The model transient PI also indicates that boundary-dominated flow will be reached soon.

The results in **Figs. 1** and **2** lead to two possible interpretations for the actual reservoir configuration. The first possibility from **Fig. 1** is a large reservoir with a localized naturally fractured region around the wellbore surrounded by an external, tight matrix. The second possibility, from **Fig. 2**, is a small, dual-porosity reservoir with the same volume as the localized naturally fractured region. For a conclusive interpretation, future behavior of the transient PI will have to be observed. (For example, an upward bend in *J* for the smaller-reservoir option would be an indication that the actual reservoir size might be larger. This would lead toward the first option. On the other hand, a smooth decline with a trend to become constant will indicate that the reservoir is limited to the naturally fractured region, as in the second option.)

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## Inflow-Control Devices

Horizontal and multilateral completions are a proven, superior development option in many reservoir situations. However, they are susceptible to coning toward the heel of the well despite their maximizing of reservoir contact. This is a result of frictional pressure drop and/or permeability variations along the well. Annular flow, leading to severe erosion and screen plugging, is another challenge. Inflow-control devices (ICDs) were proposed as a solution to these difficulties in the early 1990s. ICDs have gained popularity recently and are being applied to a wider range of field types. Their ability to control the well inflow profile has been confirmed by a variety of field monitoring techniques.

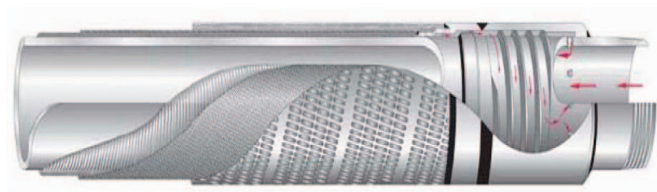
### Introduction

ICDs are a new sandface completion technology specifically developed to help balance the inflow contribution along horizontal wellbores. Extensive flow-loop testing and subsequent field experience have proved the potential of ICDs to extend well life by extending the plateau period, minimizing water and gas coning, minimizing annular flow, and increasing recovery.

### Historical Development

Norsk Hydro introduced the ICD technology in the early 1990s to enhance the performance of horizontal wells in

*This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 108700, "Inflow-Control Devices: Application and Value Quantification of a Developing Technology," by F.T. Al-Khelaiwi, SPE, and D.R. Davies, SPE, Heriot-Watt U., prepared for the 2007 SPE International Oil Conference and Exhibition in Mexico, Veracruz, Mexico, 27–30 June. The paper has not been peer reviewed.*



**Fig. 1—Helical-channel-type ICD.**

the Troll field, a giant gas field on the Norwegian shelf of the North Sea. The field contains a thin oil column (4 to 27 m thick) overlain by a large gas cap and underlain by an aquifer. The field was developed originally as a gas field in the “thin-oil-column” part of the field because the production of such a thin oil column was deemed nonviable with conventional wells. Two horizontal wells then were drilled, and long-term well tests were conducted to determine the ability of such wells to drain the oil economically. The wells were completed with large-diameter prepacked slotted liners to reduce the effect of frictional pressure losses along the wellbores. The long-term-test results indicated that a significant oil-production potential existed. The initial flow rate of the first well was four times that expected from a vertical well. The well productivity index was very high, at approximately 6000 std m<sup>3</sup>/d/bar, which is 5 to 10 times higher than that expected from a vertical well. This also meant that a small pressure drop of only 0.5 to 1.0 bar is sufficient drawdown pressure to produce the well at a target rate of 3000 to 5000 std m<sup>3</sup>/d.

A new field-development plan was put in place that used horizontal wells. However, production logging of the first test well indicated that 75% of the contribution was coming from the first half of the horizontal section. This is

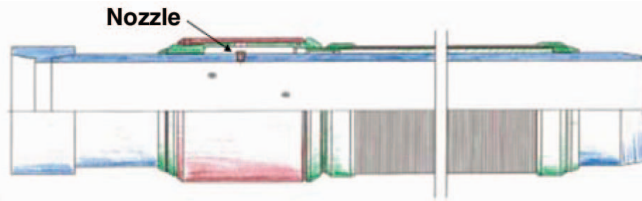
indicative of the significant effect frictional pressure losses can have on the performance of horizontal wells once this frictional pressure drop is of the order of magnitude of the drawdown.

Three completion options were proposed to overcome this problem, including a stinger method, reduced perforation density, and an innovative ICD. The original ICD concept had a number of labyrinth channels installed within a prepacked screen mounted on a solid base pipe. The fluid flowing from the formation passes through the screen and the channels before entering the casing (liner) internal section through predrilled holes in the base pipe. The length and diameter of the labyrinth channels can be adjusted to achieve the required pressure drop to balance the inflow along the length of the liner. Reservoir-simulation studies indicated that the best completion option was to install the ICDs along the length of the completion, resulting in an extension of the plateau period by 50%.

### ICD Designs

Three of the world’s leading suppliers of technology to the upstream oil and gas industry have developed their own, unique ICD design to create flow resistance (i.e., channels, nozzles, or orifices). All these designs can be mounted on a standalone screen (SAS) for use in unconsolidated formations, or they

*For a limited time, the full-length paper is available free to SPE members at [www.spe.org/jpt](http://www.spe.org/jpt).*



**Fig. 2—Nozzle-type ICD.**

can be combined with a debris filter for use in consolidated formations.

**Channel-Type ICD.** The channel-type ICD was developed by Supplier 1 as a modification to the original labyrinth ICD. The device uses a number of helical channels with a preset diameter and length to impose a specific differential pressure at a specified flow rate (Fig. 1). The produced fluid flows from the formation through a limited annular space into multiple screen layers mounted on an inner jacket. The fluid then flows along the solid base pipe of the screens to the ICD chamber, where the chosen number of channels imposes the desired choking before the fluid passes on to the inner section of the casing either through holes of preset diameter or a slotted mud filter installed to prevent the screen from being contaminated by kill mud during any future well-kill operation. This ICD is available with five flow-resistance ratings based on the diameter, length, and number of channels incorporated into the device.

The specific design of the channel-type ICD causes the pressure drop to occur over a longer interval compared to the nozzle- and orifice-type ICDs, an advantage that is thought to reduce the possibility of erosion or plugging of the ICD ports. However, this device depends on friction to create a differential pressure in addition to the acceleration effect. This implies that the actual pressure drop created will be more susceptible to emulsion effects.

**Nozzle-Type ICD.** The nozzle-type ICD was developed by Supplier 2. The device uses nozzles to create pressure resistance (Fig. 2). The fluid passing through the screen is collected in a chamber where a set of preconfigured nozzles controls the fluid flow from the chamber into the inner section of the liner joint. The number and diameter of the nozzles are chosen to produce the

desired pressure drop across the device at a specific flow rate. Constricting the fluid flow to a number of nozzles makes the pressure drop highly dependent on the fluid density and velocity but less dependent on viscosity. However, high fluid-flow velocity is one of the major causes of erosion, especially when combined with sand production.

**Orifice-Type ICD.** Supplier 3 uses multiple orifices to produce the required differential pressure for flow equalization (Fig. 3). Each ICD consists of a number of orifices of known diameter and flow characteristics. The orifices are part of a jacket installed around the base pipe within the ICD chamber, as opposed to the nozzle-type ICD. Different pressure-resistance values are achieved by reducing the number of open orifices. Although the exact location of the orifices within the ICD chamber is different from the nozzle-type ICD of Supplier 2, the flow characteristics are expected to be similar, though with minor difference in the flow-coefficient value. Details on the differences between these designs are explained in the modeling sections in the full-length paper.

### Published Applications

**SAS in Horizontal Wells.** One of the reported ICD installations is in the longest horizontal section to be completed in the Troll field. Well M-22 had a 3619-m horizontal-section length and was completed with 279 joints of SAS equipped with ICDs. Numerical simulation indicated that a “stairstep” arrangement, with the highest-strength ICD (3.2 bar) at the heel section of the well and an SAS without ICDs toward the toe of the well, was the optimum completion design. Annular isolation with external casing packers (ECPs) to prevent flow along the length of the formation face was not used. The stairstep design later was modified to a 3.2-bar single ICD strength along

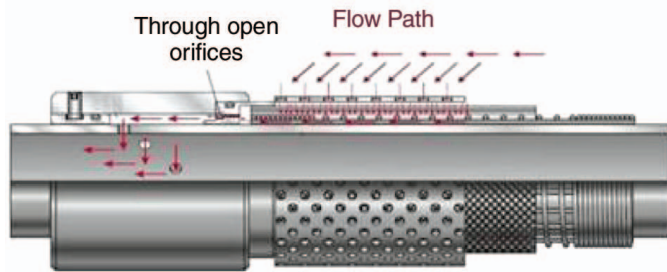
the entire horizontal section because of the insignificant increase in the simulated cumulative oil production predicted for the optimized (stairstep) design and to simplify the operational logistics at the wellsite (how to ensure that the different-strength ICDs are run into the hole in the correct order). Another important factor that influenced the decision to use a single ICD strength was the inability to calculate the magnitude of the annular flow with the available reservoir simulator. There was concern that a significant flow from the region of the high-strength ICD to that of the lower-strength ICD might occur. The full-length paper details this flow modeling.

### Integration With Annular Isolation.

**Sandstone Reservoirs.** One advantage claimed of ICDs is the elimination of annular flow. However, this will be achieved only if a highly homogeneous permeability distribution exists along the length of the horizontal wellbore. Variations in permeability or hole size or undulation along the wellbore can trigger annular flow even when ICDs are installed. In practice, annular isolation is a necessity to ensure that the full benefits of ICD installation are achieved. Different forms of annular isolation are available, including inflatable or mechanical ECPs, swell packers (SPs), constrictors, and expandable packers. Many of the reported ICD applications include one of these packer types.

Well Z-253 was completed in Zuluf field offshore Saudi Arabia, using four mechanical ECPs in conjunction with single-strength channel-type ICDs to segment a 671-m-long wellbore. ECP placement was based on the permeability of each hole section. This completion enhanced productivity and equalized the inflow of the well compared to its neighbor, a conventionally cemented and perforated well.

SPs were used for annular isolation in the West Brea 16/7a-W8z well. This horizontal well was completed with multiple ICD strengths ranging from 3.2 bar at the heel to 0.8 bar at the toe, with SPs installed when the ICD strength changed. This completion allowed an increase in the well production by an incremental rate of 795 m<sup>3</sup>/d of oil and delayed water breakthrough compared to the offset wells.



**Fig. 3—Orifice-type ICD.**

**Carbonate Reservoirs.** In carbonate reservoirs, however, annular isolation has a second objective. ECPs or SPs were installed in conjunction with (multiple) lengths of blank pipe to cover fractured or super-*k* zones. Alternatively, they can be installed with ICDs to restrict the inflow of free gas from the gas cap through high-permeability zones. An example of the former is the installation of 35 ICDs in a slimhole well in a Saudi Arabian carbonate reservoir. A total of five openhole packers were set along the completion string. Two of these packers were combined with 76 m of blank pipe to isolate a highly fractured zone that had been identified through mud losses during the drilling and image-logging operations. The remaining packers were used to separate different permeability zones. Installation of 20 ICD joints along with eight external packers was used in Well SHYB-257 to reduce the well gas/oil ratio from approximately 710 m<sup>3</sup>/m<sup>3</sup> to 430 m<sup>3</sup>/m<sup>3</sup> by restricting the gas-cap-gas influx through the high-permeability zones. All the above examples were channel-type ICD applications. Installation of a nozzle-type ICD with annular isolation was reported in Well Sakhalin-1 in the Chayvo field. The completion-string design included a predrilled liner across the low-permeability zones and ICDs across the high-permeability zones, with SPs to separate the two completion components. This helped equalize the inflow profile along the well by minimizing the contribution from the high-permeability zone, which was expected to dominate the production and suppress the contribution of the low-permeability zones.

**Gravel Pack.** ICD installation and integration with annular isolation is

intended to eliminate annular flow, a primary cause of sand particles becoming dislodged from the sandface and being transported along the annulus. Screen erosion and plugging, in addition to many sand-production-related problems at the surface, can result. However, experience with gravel packs in conventional and horizontal wells has proved their ability to eliminate or minimize sand production in various fields. In the Etame oil field, offshore Gabon, channel-type ICDs combined with a horizontal gravel pack were used in the subsea Well ET-6H both to eliminate poten-

tial sanding problems and to delay water breakthrough.

**Multilateral, Intelligent Completion.** Simulation results have indicated that the installation of ICD completions in individual laterals of dual-lateral or higher-level multilateral wells in a homogeneous formation helps even out the water and gas fluid-front movement toward each lateral. However, if the laterals are completed in different reservoir facies or at different depths, then water breakthrough in one lateral before the other will lead to a deterioration of the total well performance. This effect can be alleviated by combining an ICD completion along the well laterals with installation of inflow-control valves (ICVs) at the mouth of each lateral. The ICVs can be controlled remotely to adjust the flow contribution of each lateral upon the onset of unwanted (water or gas) fluid production. An integrated ICD completion with Level-4 multilateral junctions equipped with ICVs to control the production from each lateral was implemented in the Z field, offshore Saudi Arabia. **JPT**

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