Stimulation Effectiveness in Multilayered, Tight Gas Reservoirs: Pinedale Anticline Area

Low-permeability, or "tight," gas reservoirs are being developed at an ever-increasing rate in the U.S. Currently, there are several tight gas plays in the U.S. where multiple intervals are commingled for economic viability. The Pinedale anticline completions pose a complex problem in determining the best stimulation method because as many as 22 separate stimulation treatments are placed in as many as 70 discrete sands over a 6,000-ft-thick interval. Evaluation is complicated by permeability variations that exceed two orders of magnitude and pore-pressure gradients that range from 0.22 to 0.83 psi/ft.

Introduction

Development of the Pinedale anticline in southwestern Wyoming has continued at an aggressive pace over the past several years. Massive hydraulic-fracturing (MHF) treatments are the only way to stimulate production from the tight gas sands present in this area to economically acceptable levels. Generally, each well requires between 14 and 22 MHF treatments to produce effectively from all potential pay intervals. Often, more than 2 million lbm of proppant is used per well, representing a high investment cost to the operator. The ability to evaluate the incremental production associated with the use of one proppant vs. another can have a significant effect on field profitability.

This article, written by Assistant Technology Editor Karen Bybee, contains highlights of paper SPE 100574, "Using Reservoir Modeling To Evaluate Stimulation Effectiveness in Multilayered 'Tight' Gas Reservoirs: A Case History in The Pinedale Anticline Area," by ***S.K. Schubarth,*** *SPE, Schubarth Inc.;* ***J.P. Spivey,*** *SPE, Phoenix Reservoir Software LLC; and* ***P.T. Huckabee,*** *SPE, Shell E&P Co., prepared for the 2006 SPE Gas Technology Symposium, Calgary, 15–17 May.*

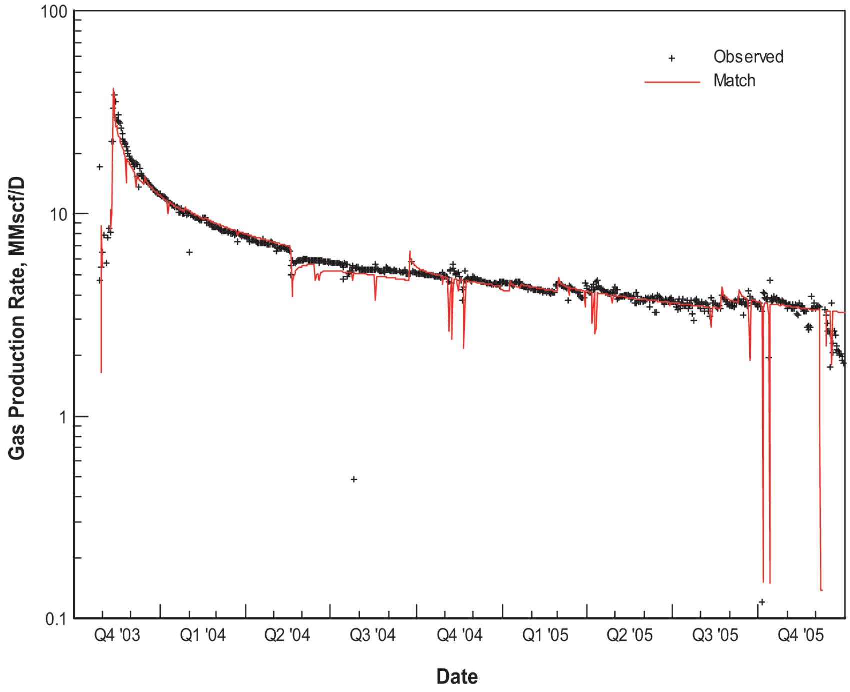

Fig. 1—Production history match—example well.

Data Analysis

Production and completion information from 11 wells with 172 fracture-treated intervals was included in this analysis. Production information was updated, and all 11 wells have at least two production logs, with one early in the well life. A detailed production history also was available for all wells for use in the reservoir-simulation evaluation. Six different proppants were used in the fracture treatments pumped.

Reservoir Simulation. For single-layer tight gas reservoirs, fracture and reservoir properties usually are estimated by analyzing production data. Methods for such single-layer analysis include advanced decline-curve analysis with constant-terminal-pressure type curves, type-curve matching with constant-terminal-rate type curves, and automatic history matching with a single-layer analytical reservoir simulator. Single-layer analysis methods may provide estimates of in-situ permeability to gas, fracture half-length, fracture conductivity, and drainage area, which are used in evaluating the success of a fracture treatment, selecting restimulation candidates, optimizing future fracture treatments, forecasting future performance, and estimating reserves.

In commingled multilayer unconventional gas reservoirs like those of the Pinedale anticline area, production data alone do not provide sufficient information to estimate individual-layer properties. While data from multilayer reservoirs can be analyzed by use of single-layer methods, the results give only the effective properties of an equivalent single-layer reservoir. This is further complicated for Pinedale anticline completions by the large variation in permea-

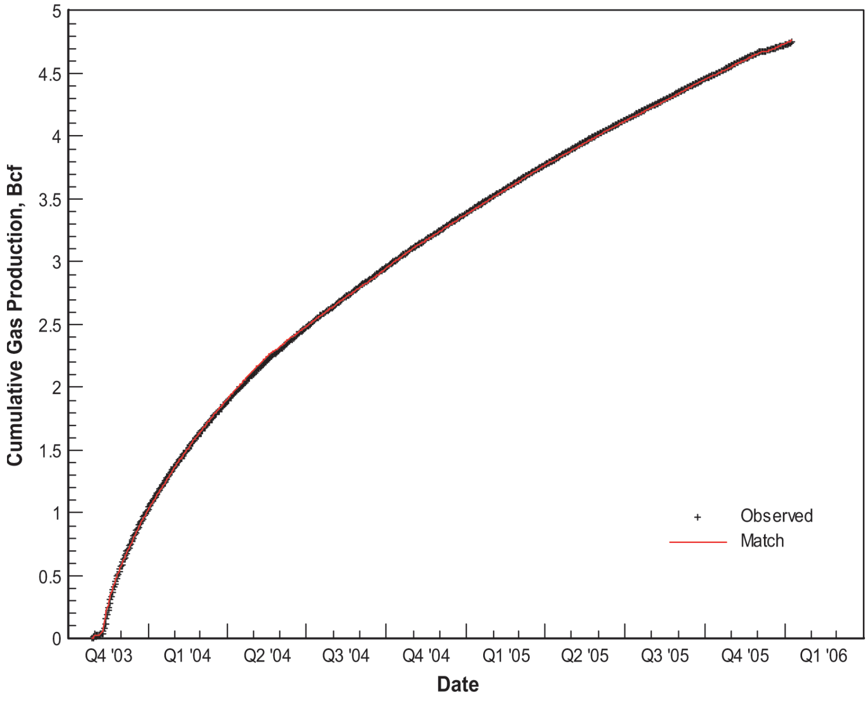

Fig. 2—Cumulative-production history match.

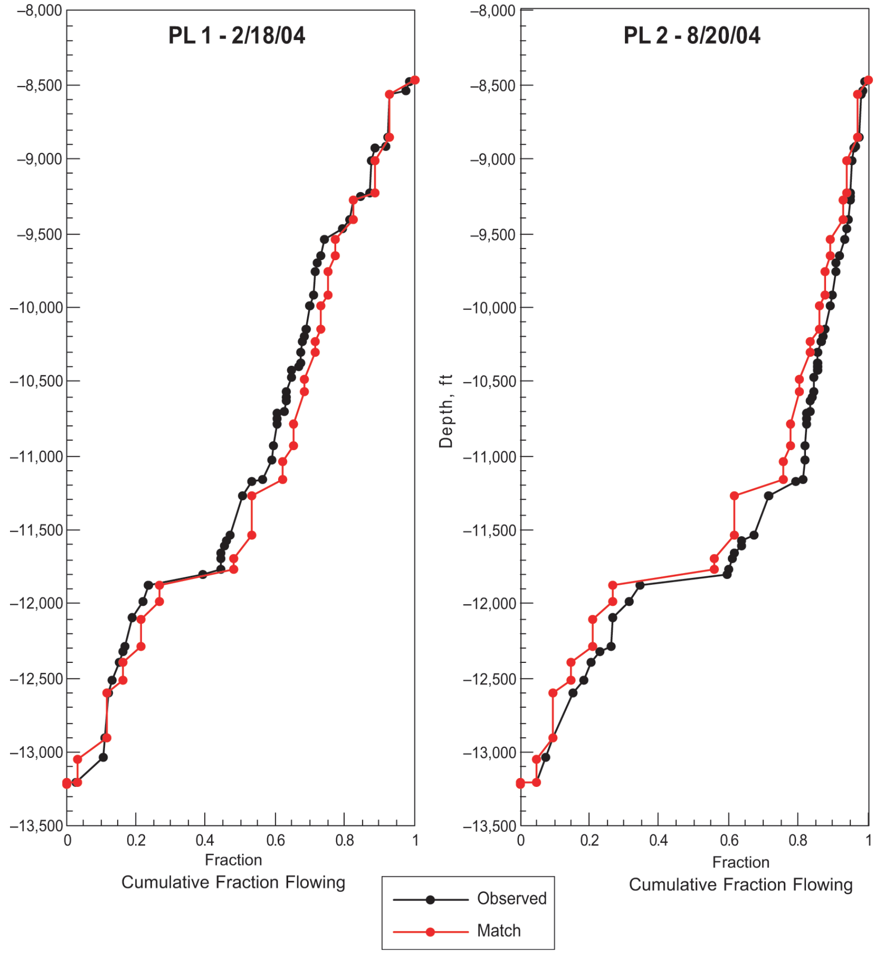

Fig. 3—Production log match.

bility and pore-pressure gradients. Thus, the reservoir-simulator results cannot be used to make decisions regarding stimulation effectiveness for individual layers of a multilayer reservoir.

Production logs can be used to measure wellbore flow rate and flowing wellbore pressure vs. depth for a multilayer reservoir at a single point in time. Production-log data provide a great deal of information about the individual layers that is not provided by surface production data. Because the relative contribution of each layer to the total flow rate changes over time, multiple production logs may be run at different points in time to capture the changing layer contributions.

For this study, individual-layer properties were estimated by use of a new, fully coupled reservoir/wellbore single-well analytical simulator for multilayer, unconventional gas reservoirs that automatically history matches production and production-log data simultaneously. By history matching data from multiple production logs as well as surface production data, the simulator provides accurate estimates of individual-layer properties such as permeability, fracture length, and drainage area. The ability to differentiate these values is crucial when trying to compare stimulation effectiveness of fracture-treatment designs and materials.

The total well-production stream was matched by simulation of each individual interval. The production history of each interval was required to match production-log values at the date the log was performed. The reservoir model varied reservoir permeability, effective fracture half-length, and drainage area to achieve a match of the production history and production logs. **Figs. 1, 2, and 3** show examples of the production matches.

Proppants

Six different proppants were used to fracture treat the 172 intervals in this analysis. Sand, two resin-coated sands, two intermediate-strength ceramic proppants, and one economy lightweight ceramic were used. The operator selected proppant applications by considering a parametric sensitivity analysis by use of software, a comparison of offset-well performance, and completion-cost management.

Each proppant has laboratory-measured baseline conductivity vs. stress on proppant pack. Because each proppant is used at varying stress conditions in the field, it is important to know how the delivered conductivity of each changes

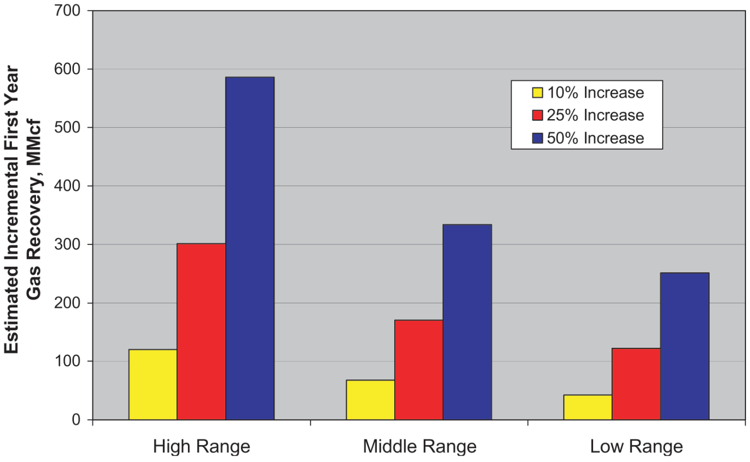

Fig. 4—Estimated incremental gas recovery.

with stress. The analysis compared the laboratory conductivity data, corrected by a common multiplier, to the estimated fracture conductivity from reservoir-simulation results.

The reservoir-simulation production history-matching process provided a value for reservoir permeability and effective fracture half-length for each interval. The effective fracture half-length was obtained by matching that used an infinite-conductivity fracture. While this may not be the way the fractures behave in the field, it removes the need to know the finite conductivity and the length to estimate stimulation effectiveness. Use of an infinite-conductivity fracture allows direct comparison of stimulation effectiveness for each interval. On the basis of effective fracture half-length from reservoir-simulation analyses, only slightly more than 10% of the intervals completed have an effective fracture half-length greater than 300 ft, although all hydraulic-fracture treatment designs were for greater lengths. This indicates that if the propped lengths are greater than the analyses results, then the fractures are of finite conductivity or have failed to clean up effectively. Also of note are the points indicating treatments that screened out or failed to be pumped to completion. Interestingly, all of these occurrences are at or above the 50% mark, meaning they are in the better half of the results.

Both the reservoir permeability and effective fracture half-length were provided by the reservoir-simulation analyses. After obtaining both of these values, the estimated fracture conductivity can be calculated because of the assumption that the fractures have infinite conductivity. This would be a lower bound for fracture conductivity. However, because it appears that most of the fractures have limited conductivity because of their shorter than expected lengths, it will be an upper bound on the in-situ fracture conductivity.

The distribution of conductivity values varies over a wide range. However, the lower 30% of the data appears to be disjointed from the data above the 30% mark. This requires additional analysis. One explanation of the poor conductivity performance is that proppant transport-fluid cleanup is not effective on these stages. Alternatively, these very-low calculated conductivity values could be the result of completion damage. Some data indicated that as the number of commingled stages completed in a single wellbore increases, the average stimulation effectiveness decreases. This may mean that fracture stages were damaged during the completion process. Considerable effort and investment were expended in engineering and implementing completions to manage crossflow mechanically and operationally during all stimulation, drillout, and flowback operations to reduce potential damage in the commingled completions.

Conductivity. Estimated fracture conductivity was plotted against in-situ stress on the proppant to provide an appropriate comparison of the performances of the proppants. There appears to be a low-performance interval between 7,000- and 8,500-psi in-situ stress. Variation in conductivity for each of the proppants examined is large; however, the centering of that variation around the expected value of the adjusted laboratory data indicates that each proppant is delivering the conductivity it was designed to deliver. The large variation in conductivity suggests one or more of the following.

- Difficulty in placing adequate areal proppant concentration consistently.
- Difficulty in cleaning up transport-fluid conductivity damage consistently.
- Difficulty in unique resolution of formation permeability, fracture properties, and reservoir-geometry variation in the depositional environment at Pinedale.
- Something not yet considered.

The extremely low conductivity values relative to laboratory-measured values indicate that treatment design and propped-fracture geometries should be investigated to determine if improvement can be made through treatment design rather than proppant selection alone. The fact that the graphs indicate that each proppant is performing as expected means that the economic benefit of one proppant over another can be quantified because increased stimulation effectivensss will be a function of the conductivity delivered.

Economic Benefit of Conductivity

Conductivity is related directly to stimulation effectiveness. If the conductivity of a limited-conductivity fracture as opposed to infinite-conductivity fracture can be increased by 25%, then the effective fracture half-length should be increased by 25%. Increasing the conductivity of a fracture by 25% can be accomplished by selecting a proppant that has 25% more conductivity at the same concentration. Alternatively, the treatment design can be changed to increase the concentration of proppant in the fracture. Also, reducing damage potential from proppant-transport fluids should be considered. The method that proves to be the most beneficial economically should be selected.

The reservoir-simulation model was used to modify the history-matched fracture parameters to include greater effective fracture half-length to examine the benefits that could be realized through increased conductivity resulting from increased stimulation effectiveness. Example low-, middle-, and high-rate producers were selected for modification. Ten, 25, and 50% increases in effective fracture half-length were examined. **Fig. 4** shows the incremental first-year gas production that could be expected. JPT