Integrating Short-Term Pressure Buildup Testing and Long-Term Production Data Analysis to Evaluate Hydraulically-Fractured Gas Well Performance

J.A. Rushing, SPE, Anadarko Petroleum Corp., and T.A. Blasingame, SPE, Texas A&M University

Abstract

This paper presents an integrated approach for evaluating the post-fracture performance of gas wells completed in tight gas sands. Our technique focuses on a methodology for evaluating the stimulation effectiveness of hydraulically fractured gas wells. Rather than relying on a single evaluation technique, we integrate short-term pressure buildup testing with long-term production data analysis using decline type curves. We illustrate the applicability and efficacy of our technique with examples from more than twenty wells completed in tight gas sands. The results of our paper also demonstrate the value and function of short-term pressure buildup tests performed in tight gas sands.

Introduction

Most wells completed in tight gas sands require stimulation to achieve economic production. Depending on the type and size of stimulation treatment, hydraulic fracturing may be very expensive, often representing a significant portion of the total well completion costs. Since the economic viability of many wells completed in low-permeability reservoirs depends on minimizing costs, then it is imperative to optimize fracture treatments. Fracture optimization is achieved by finding the proper balance between stimulation costs and well productivity. A key component in achieving this balance is a post-fracture evaluation program to determine stimulation effectiveness, principally effective fracture conductivity and propped fracture length.

A number of techniques have been developed by the petroleum industry for evaluating hydraulically-fractured gas well performance. Unfortunately, no single methodology is perfect. Theoretical assumptions, model applicability, and/or data requirements limit each analysis technique. Therefore, we employ an integrated approach in which we capture the benefits and utilize the strengths of several types of fractured well diagnostic techniques. Several previous papers have illustrated the effectiveness of such an integrated approach.

Cipolla and Wright have identified and grouped fractured well diagnostic techniques into three general categories: direct far-field, direct near-wellbore, and indirect. We focus on the integration of indirect techniques, particularly pressure transient testing and production data analysis.

Pressure buildup testing is the most effective indirect technique for evaluating the stimulation effectiveness of hydraulically fractured gas wells. But, knowledge of reservoir permeability, either from the well test or from an independent source, is required to compute fracture properties. If a well is shut in for a sufficient time to reach the pseudoradial flow period, then we can uniquely determine reservoir permeability. Unfortunately, wells completed in tight gas sands usually require very long shut-in times to reach pseudoradial flow. Most operators are reluctant to shut in a well for extended periods, especially under favorable gas product pricing scenarios. If, however, we have an estimate of reservoir permeability from an independent source, then shorter duration pressure buildup tests in tight gas sands become practical.

Conventional decline type curve analysis of production data is a viable alternative for evaluating well performance without shutting in the well. Unlike pressure transient test analysis, decline type curves do not rely upon identification of characteristic flow regimes for the analysis. As a result, we cannot always obtain unique estimates of fracture half-length, especially when using poor-quality production data. Other production analysis techniques consider the production data to be an extended drawdown test. Accordingly, these techniques use variable-rate pressure transient testing theory and superposition plotting functions to analyze the production data. Unlike conventional decline type curve analysis techniques, these methods allow us to identify specific flow regimes. However, we still cannot quantify fracture properties unless we have an estimate of reservoir permeability.

Evaluation Methodology

To overcome these problems with post-fracture evaluation techniques, we have developed an analysis methodology that integrates short-term pressure buildup testing and long-term production data analysis using conventional decline type curves. Although several decline type curves are applicable, we selected the material balance decline type curve (MBDTC) methodology developed by Palacio and Blasingame.
Theoretical aspects of the MBDTC analysis technique have been discussed previously and will not be repeated in detail in this paper. In general, the type curve method is applicable to variable rate, variable bottomhole flowing pressure, or combinations of these flowing conditions. Use of three different type curve plotting functions—normalized rate, rate integral, and rate derivative against material balance time—allows us to obtain more unique type curve matches, even from typical field data with significant scatter. Since the plotting functions were developed in terms of pseudopressures and pseudotime variables, then the type curves are applicable to gas well production data analysis. Moreover, the type curves were developed for an infinite-conductivity vertical fracture, so they may not be appropriate for all fractured well conditions, especially those wells with very low fracture conductivities.

Our iterative technique begins with initial estimates of permeability and fracture half-length from decline type curve analyses of the well production data. We then use the pressure derivative plot of the pressure buildup data to identify flow regimes characteristic of hydraulically fractured wells. Depending on the type of flow regimes present, we may then use special plotting functions and analysis techniques to compute fracture properties. Next, we use an automatic history-matching process to analyze the test data. Estimates of formation permeability from the decline type curve analysis and fracture properties from the special analyses are used to establish initial estimates and reasonable ranges for the parameters during the history-matching process. We then iterate between analyses until consistent results are obtained.

**Integrated Analysis Procedure.** The procedure outlined below assumes that a pseudoradial flow period will not be present. If, however, the well test exhibits pseudoradial flow, then that data should be incorporated into the analysis. The working equations are also derived based on a pseudopressure and normalized pseudotime formulation. Note that the equation format will change if different pressure and time variables during the history-matching process. We then iterate between analyses until consistent results are obtained.

1. Analyze the post-fracture gas production data using a decline type curve methodology. For this paper, we use the material balance decline type curves (MBDTC). Estimate effective gas permeability ($k_g$) and effective fracture half-length ($L_f$).

2. Prepare a plot of pseudopressure change and derivative of pseudopressure change against normalized equivalent or superposition pseudotime function using the pressure buildup test data. Identify all flow regimes characteristic of hydraulically fractured wells from the shape of the derivative data.

3. If the bilinear flow period is present, prepare a Cartesian plot of pseudopressure against the fourth root of normalized pseudotime function. Compute the slope ($m_B$) of the line drawn through the bilinear flow period identified from Step 2. Using $k_g$ from the MBDTC analysis and $m_B$ from the bilinear plot, compute effective fracture conductivity, $w_f k_f$:

$$w_f k_f = \left( \frac{444.75 q_g T}{h m_B} \right)^2 \frac{1}{\phi \mu_g c_f k_g} \quad \text{(1)}$$

4. If the formation linear flow period is present, prepare a Cartesian plot of pseudopressure against the square root of normalized pseudotime function. Compute the slope ($m_e$) of the line drawn through the formation linear flow period identified from Step 2. Using $k_g$ from the MBDTC analysis and $m_e$ from the formation linear plot, compute effective fracture half-length, $L_f$:

$$L_f = \left( \frac{40.925 q_g T}{h m_e} \right)^{1/2} \frac{1}{\phi \mu_g c_f k_g} \quad \text{(2)}$$

5. Compute the dimensionless fracture conductivity, $F_{CD}$, using estimates of $w_f k_f$, $L_f$ and $k_g$:

$$F_{CD} = \frac{w_f k_f}{L_f k_g} \quad \text{(3)}$$

6. Use an automatic history-matching process to analyze the test data. Estimates of formation permeability from the decline type curve analysis and fracture properties from the special analyses are used to establish initial estimates and reasonable ranges for the parameters during the history-matching process. Iterate between analyses until consistent results are obtained.

Application of our integrated approach is illustrated with several field examples from the Bossier tight gas sand play in the East Texas Basin. All of these wells were stimulated with various types of water-frac techniques.

**Field Example 1**

The first field case is an example of a well completed with a small conventional water-frac. The well was drilled and completed in August of 2001. Following a water-frac with 5,281 bbl slick water and 28,605 lbs 30/50 proppant pumped at an average rate of 67 bpm, the well produced at an initial rate of slightly more than 2,000 Mscf/day (Fig. 1). The well was shut in December 13, 2001 for a two-week pressure buildup test.

Initial estimates of permeability and fracture half-length were obtained from a material balance decline type curve (MBDTC) analysis of the production data. The type curve match shown in Fig. 2 is a log-log plot of normalized rate, integral of normalized rate, and derivative of rate integral against material balance time. Note that all rate functions are derived in terms of the pseudopressure function, while the time variable is derived in terms of the pseudotime function. The solid lines in Fig. 2 correspond to the dimensionless type curves, while the discrete points represent the corresponding dimensional discrete field data. We estimate $k_g = 0.0169$ md and $L_f = 45.7$ ft.
Because of the significant rate changes prior to shutting in the well, we analyzed the pressure buildup data using both pseudopressure and pseudotime superposition functions. A log-log plot of the pseudopressure change and pseudopressure derivative functions against the normalized pseudotime superposition function is shown in Fig. 3. Possible flow regimes characteristic of hydraulically fractured wells are indicated by the solid black lines. The one-quarter slope line identifies bilinear flow, while the line with a slope of one-half indicates formation linear flow. Note that, although we cannot positively identify a pseudoradial flow period, it may be developing at the end of the test as indicated by the flattening of the pressure derivative.

As we mentioned previously, the next step is to use special plotting functions to validate various flow patterns identified from the log-log derivative plot. The bilinear flow regime is indicated by the straight line on a plot of pseudopressure against the fourth root of pseudotime superposition function shown in Fig. 4. If we have identified the correct straight line on the curve, then we can use the bilinear flow line data slope to estimate effective fracture conductivity as defined by Eq. (1). On the basis of the line slope from Fig. 4 and $k_e$ from the MBDTC analysis, we estimate $w_{kf}$ 6.2 md-ft. Moreover, if we substitute $L_f$ and $k_e$ from the MBDTC analysis and $w_{kf}$ from Fig. 4 into Eq. (3), we compute $F_{cp} = 8.0$.

Similarly, the formation linear flow regime is indicated by a straight line on the plot of pseudopressure against the square root of pseudotime superposition function shown in Fig. 5. Again, assuming we have identified the correct straight line, then we can use this line slope, $m_L$, to estimate effective fracture half-length as defined by Eq. (2). Using the slope of this line and $k_e$ estimated from MBDTC analysis, we compute $L_f = 41.8$ ft, which is very similar to the value estimated from the decline type curve analysis.

On the basis of the derivative plot in Fig. 3, we did not observe the pseudoradial flow regime. As a result, we cannot use conventional semilog analysis techniques to compute formation permeability from the well test. Instead, we used an
automatic history-matching process during which we allowed \( k_g \), \( L_f \), and \( F_{CD} \) to vary. To assess the importance of non-Darcy flow in the well test analysis,\textsuperscript{27,28} we also included a rate-dependent skin factor defined by the non-Darcy flow coefficient, \( D \). Estimates of formation permeability from the decline type curve analysis and fracture properties from the special analyses were used to establish initial estimates and reasonable ranges for the parameters during the history-matching process. We then iterated several times until we obtained consistent results from all analyses.

The final and best history match is shown in Fig. 6. The solid lines drawn through the well test data represent the final history-matched solution. Note that results from the pressure buildup test analysis are very similar to that from the decline type curve analysis. We estimate \( k_g \) and \( L_f \) are 0.0134 md and 44.1 ft, respectively. In addition, the results suggest the stimulation treatment generated a short fracture with relatively low conductivity. We compute \( w_kF_{CD} = 13.7 \) md-ft corresponding to \( F_{CD} = 23.3 \).

The MBDTO analysis of the post-fracture production data is shown in Fig. 8. The evaluation yielded \( k_g = 0.0261 \) md and \( L_f = 206.6 \) ft.

A log-log plot of the pseudopressure change and pseudopressure derivative functions against the pseudotime superposition function is shown in Fig. 9. We observe both bilinear and formation linear flow periods, as indicated by the solid black lines with slopes of one-quarter and one-half, respectively. We do not, however, see evidence of pseudoradial flow.

Field Example 2

The next example illustrates a well with a very conductive and long effective fracture half-length. The stimulation treatment for this well began by injecting 5,405 bbl slick water with 2,500 gal 15% HCl and 50,000 lbs 40/70 sand followed by 2,857 bbl of 30 lbs/1000 gas cross-linked gel with 250,000 lbs 20/40 proppant. The initial rate was slightly less than 12,000 Mscf/day (Fig. 7). The well produced for about six months before being shut in for a two-week pressure buildup test.

The bilinear and formation linear flow regimes are also identified and validated by the plots of pseudopressure against fourth-root and square-root of pseudotime superposition functions shown in Figs. 10 and 11, respectively. Using \( m_B \) from the line drawn through the bilinear flow period in Fig. 10 and \( k_g \) estimated from the MBDTO analysis, we compute \( w_kF_{CD} = 121.6 \) md-ft. Further, if we use \( k_g \) and \( L_f \) estimates from the MBDTO analysis of the production data, we estimate \( F_{CD} = 22.6 \).

As indicated by the straight-line on the plot of pseudopressure against the square root of pseudotime superposition function shown in Fig. 11, the formation linear flow period is very well defined. Using \( m_L \) from the line drawn through the formation linear flow period and \( k_g \) estimated from the MBDTO analysis, we compute \( L_f = 260.1 \) ft. Again, the fracture half-lengths estimated from the
MBDTC and square-root-of-time analyses are generally in agreement.

Fig. 10—Fourth-root-of-time plot showing bilinear flow regime from two-week pressure buildup test, Field Example 2.

Fig. 11—Square-root-of-time plot showing formation linear flow regime from two-week pressure buildup test, Field Example 2.

Like the first field example, we did not see evidence of a pseudoradial flow period on the log-log plot of the pressure derivative. Consequently, we could not use conventional semilog techniques to compute permeability. Again, we used an automatic history-matching process to analyze the well test data. The final and best history match for Field Example 2 is shown in Fig. 12. Note that results from the pressure buildup test analysis are very similar to those estimated from the decline type curve analysis. We estimate $k_g$ and $L_f$ are 0.0276 md and 290.1 ft, respectively. The results also suggest the stimulation treatment generated a long and very conductive fracture. We compute $w_f k_f = 250.9$ md-ft corresponding to $F_{CD} = 39.2$.

Field Example 3

The next field example illustrates a successful large conventional water-frac stimulation treatment. The well was hydraulically fractured on October 8, 1999 with 8,175 bbl slick water and 237,000 lbs 20/40 proppant. As shown by the production history in Fig. 13, the initial gas rate was almost 12,000 Mscf/day. After producing for about 14 months, the well was shut in for a two-week pressure buildup test on December 31, 2000. We compute $k_g = 0.0219$ md and $L_f = 223.3$ ft from the material balance decline type curve analysis of the post-fracture production data, as shown in Fig. 14.

A log-log plot of the pseudopressure change and pseudopressure derivative functions against the pseudotime superposition function is shown in Fig. 15. The solid black lines identify bilinear and formation linear flow regimes. Note that, similar to the previous examples, we did not observe development of a pseudoradial flow period.

The bilinear and formation linear flow patterns are also identified and validated by plots of pseudopressure against fourth-root and square-root of pseudotime superposition functions shown in Figs. 16 and 17, respectively. Using $m_B$ from the line drawn through the bilinear flow period as well as $k_g$ from the MBDTC analysis, we compute $w_f k_f = 128.8$ md-ft. Similarly, if we use $k_g$ and $L_f$ estimated from the MBDTC...
analysis of the post-fracture production data, we also estimate $F_{CD} = 26.3$.

Like the previous examples, the absence of a pseudoradial flow period precludes use of conventional semilog analysis techniques to compute permeability from the well test. Alternatively, we used an automatic history-matching process to analyze the well test data. The best history match is shown in Fig. 18. We estimate $k_g$ and $L_f$ are 0.0272 md and 235.3 ft, respectively. In addition, these results indicate the stimulation treatment generated a long and very conductive fracture. We compute a fracture conductivity of 250.9 md-ft corresponding to a dimensionless fracture conductivity of 39.2.

Validation of Integrated Evaluation Technique
To assess the validity of our integrated evaluation technique, we analyzed several pressure buildup tests numerically. We then compared the results to the integrated analytical approach. We illustrate the results of the numerical well test analysis for Field Example 4. Because this well has a very low-conductivity fracture, it represents an extreme test case for our integrated (analytical) evaluation technique.

Integrated (Analytical) Well Test Analysis. The last field example illustrates a large conventional water-frac stimulation treatment that generated a fracture with long effective half-length but very low effective conductivity. The well was stimulated in three stages, with each stage being composed of 8,500 to 10,000 bbl slick water and 170,000 to 230,000 lbs 20/40 proppant. The well produced for about two years before being shut in for a two-week pressure buildup test. The gas production and flowing wellhead pressure histories are shown in Fig. 19. The MBDTC analysis of the post-fracture production data, shown in Fig. 20, yielded $k_g = 0.011$ md and $L_f = 101.7$ ft.

A log-log plot of the pseudopressure change and pseudopressure derivative functions against the pseudotime superposition function is shown in Fig. 21. The solid black line with a one-quarter slope indicates a significant portion of the test was dominated by bilinear flow. We do not observe either a formation linear or a pseudoradial flow period.

The presence of bilinear flow is validated by the straight line on the plot of pseudopressure against fourth root of pseudotime superposition function shown in Fig. 22. From Eq. (1), we compute a very low effective fracture conductivity...
of 2.8 md-ft. Similarly, if we use $k_g$ and $L_f$ estimated from the MBDTC of the production data, we also estimate $F_{CD} = 2.5$.

**Fig. 19**—Post-fracture gas production and wellhead flowing pressure, Field Example 4.

**Fig. 20**—Material balance decline type curve analysis of post-fracture gas production, Field Example 3.

**Fig. 21**—Log-log plot identifying flow regimes characteristic of hydraulically fractured wells, Field Example 3.

As shown by the history-matched solution in Fig. 23, we estimate $k_g$ and $L_f$ are 0.0068 md and 221.3 ft, respectively. The results suggest the stimulation treatment generated a long effective half-length but very low effective conductivity. Note also that the fracture half-length from the MBDTC analysis was significantly less than that computed from the well test. Recall that the material balance decline type curves were derived assuming an infinite-conductivity vertical fracture. Consequently, the MBDTC will underestimate the effective fracture half-length for a low finite conductivity fracture.

**Fig. 22**—Fourth-root-of-time plot showing bilinear flow regime from two-week pressure buildup test, Field Example 4.

**Fig. 23**—Results from automatic history-match of two-week pressure buildup test, Field Example 4.

### Numerical Well Test Analysis

To demonstrate the validity of our analysis technique, we present the results of the numerical well test analysis for Field Example 4. We developed a two-phase (gas-water), three-dimensional, multi-layer finite-difference model. To reduce computational time, we simulated one quarter of the reservoir with a Cartesian grid system. Moreover, we used a Cartesian rather than a radial grid system so that we could more accurately model the linear flow patterns characteristic of hydraulically fractured wells.

We used data from a comprehensive core description and evaluation program to populate the grid blocks vertically. The core data suggested significant reservoir heterogeneity in the vertical direction, so we built the model using 120 hydraulic flow units distributed over an interval of about 300 ft. The flow units were generated using a methodology described in References 29 and 30. Water saturations were distributed vertically using core-derived capillary pressure curves.

We input the gas production history shown in Fig. 19 and history-matched the well flowing and shut-in pressures. Fracture properties, including effective fracture half-length and fracture permeability, as well as absolute permeability and effective porosity were varied until we matched the pressure history. Our best match, shown in Fig. 24, was obtained with a fracture permeability of 10 md, a fracture half-length of 270 ft. On the basis of the modeled fracture grid width of 0.5 ft, we compute an effective fracture conductivity of 5 md-ft,
which is very close to that estimated from the pressure buildup test analysis. Similarly, the simulated effective fracture half-length of 270 ft agrees with the value estimated from the integrated well test and decline type curve analyses. Although not shown in this paper, we have successfully matched results from the analytical and numerical techniques on several other wells. Consequently, we feel that our technique is valid for evaluating hydraulically-fractured gas well performance.

![Fig. 24—Numerical well test analysis of two-week pressure buildup test, Field Example 4.](image)

Results of Post-Fracture Performance Analysis
We have applied our integrated post-fracture performance evaluation technique to 22 wells producing from the Bossier tight gas sand play in both the East Texas and North Louisiana Salt Dome Basins. All of these wells were stimulated using various water-frac techniques, ranging from water-fracs with little to no sand, water-fracs with large sand concentrations, and a hybrid water-frac technique. Results from both the material balance decline type curves and well test analysis are shown in Figs. 25 and 26.

As shown by Fig. 25, we generally observed good agreement between effective gas permeability computed from the material balance decline type curve and the pressure buildup test analyses. Similarly, we see good agreement with effective fracture half-lengths computed from both methods. Most of the differences, especially in estimated fracture half-lengths, can be attributed to wells with low or very low conductive fractures. Since the current version of the MBDC used in this study was derived for infinite-conductivity vertical fractures, then we would not necessarily expect close agreement. New type curves for finite-conductivity fractures have been developed.

Based on our experiences with the MBDC analysis technique, we believe these decline type curves are an excellent tool for well performance analysis, reservoir surveillance and monitoring, and reservoir characterization studies, particularly in tight gas sands. However, a critical element in the successful application of the decline type curve methodology is directly related to the frequency and quality of the well production data. We have had the most success with well performance evaluations when accurate daily production data, including well flowing pressures, are used.

![Fig. 25—A comparison of effective gas permeabilities computed from the material balance decline type curve and well test analyses.](image)

![Fig. 26—A comparison of effective fracture half-lengths computed from the material balance decline type curve and well test analyses.](image)

Summary and Conclusions
We have developed an integrated approach for evaluating the post-fracture performance of gas wells completed in tight gas sands. Our technique focuses on application of short-term pressure buildup testing and long-term production data analysis using decline type curves for evaluating the stimulation effectiveness of hydraulically fractured gas wells. This integrated technique captures the benefits and advantages of each method, thus both complementing and supplementing each technique. Application of this evaluation technique demonstrates the tremendous value of short-term pressure buildup testing in tight gas sands.

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Nomenclature

- \( D \) = non-Darcy flow coefficient, \((\text{Mscf/d})^{-1}\)
- \( F_{CD} \) = dimensionless fracture conductivity = \( wj/k_fL_f \)
- \( k_f \) = fracture permeability, \(\text{md}\)
- \( k_g \) = effective permeability to gas, \(\text{md}\)
- \( L_f \) = effective fracture half-length, \(\text{ft}\)
\[ q_{r} = \text{gas flow rate, Mscf/day} \]
\[ T = \text{reservoir temperature, } ^\circ \text{R} \]
\[ w_{kf} = \text{effective fracture conductivity, md-ft} \]

References