Production Data Analysis — Future Practices for Analysis and Interpretation

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Abstract
The advent of continuous reservoir analysis is upon us — the data acquisition systems, the analysis/interpretation tools, and the modeling capability to address essentially any production scenario exist now! The analysis/interpretation of legacy data, which brought about new analysis and modeling tools, will be with us for a while (perhaps always), but now is the time to address the future of reservoir performance analysis — specifically:

1. The analysis of "continuously" measured rates and pressures (downhole/surface measurements taken on the basis of hours, minutes, or even seconds), which we have called "continuous analysis." Such data and analyses will provide an on-demand assessment of well productivity and capacity, as well as evaluate the influence of a single well in a multiwell reservoir system.

2. The analysis of "regularly" measured rates and pressures (measurements taken on the basis of days) where such measurements are most likely surface-derived. In this case, such data provide "diagnostic analysis" where we can assess aggregate changes in well performance. We can still utilize these data for high quality analysis/interpretation, but we will most likely not forgo well testing as a mechanism to assess specific well productivity issues. We also note that daily production data can be used to create reliable production forecasts.

3. The analysis of legacy data which consists of irregular measurements and may be of only fair (or even poor) quality. These data formed the motivation for the development of modern production data analysis methods, but we must again revisit our expectations for the analysis and interpretation of such data.

This paper focuses on the analysis/interpretation of "continuously" and "regularly" measured rates and pressures using pressure transient and production data analysis solutions. The primary goal of this work is to provide demonstration examples and commentary as to best practices — present and future for production data analysis. The secondary goal of this work is to instill a sense of urgency in measurement practices — measurement of rate and pressure data on a continuous basis is essential for future efforts in reservoir engineering and reservoir characterization.

Introduction
Orientation: In this work we choose to use demonstration (field) cases to illustrate the interpretation, analysis, and modeling aspects of production data analysis. The primary issue with regard to data analysis is accuracy and coherency (i.e., relevance) of the data being analyzed.

The premise of this work is that all data are "accurate" (at least to some degree) unless such data are deliberately corrupted or completely distorted by data noise. An example of data corruption could be omitted or deleted data in an otherwise complete data sequence. Data corruption is not a matter for study in this work, but rather, we wish to warn the user audience that data corruption exists — and one
would be foolish to believe that he or she will not analyze corrupted production data (sometimes even on a regular basis).

We propose that there are two types of data which can be analyzed — "continuous" data measurements (permanent installations with high frequency capabilities) and "regular" data measurements (generally daily or monthly measurements). We make this distinction because the "continuous" measurements are obtained with a philosophy of a continuous analysis (or the ability to assess the state of the reservoir at that time). On the other hand, "regular" measurements are more of a surveillance/maintenance philosophy. Did something happen between measurements? Does the trend of the data imply anything with regard to the productivity of the well/reservoir?

**Diagnostic Methods for Production Data Analysis:** Simply stated, the diagnostic methods for production data analysis are designed to provide the following:

- **Evidence of transient flow:** Transient flow implies that well performance is uniquely tied to reservoir properties and the well completion (e.g., a hydraulically fractured well in a low permeability formation). The reservoir boundaries do NOT significantly influence transient flow behavior.

- **Evidence of boundary-dominated flow (pseudosteady-state):** Boundary-dominated flow implies that volumetric (depletion) behavior dominates the well performance. During boundary-dominated flow the variable of most significant influence is the contacted reservoir volume.

- **Evidence of data correlation or corruption:** Such evidence is often difficult to quantify — intense scrutiny of production data leaves one with the impression that this type of data are essentially all noise. From a distance, production data can provide a response that "seems reasonable" (when it is not). So the trick is to view each data set according to its origin (operating company, location, etc.) as well as the rationale for which the data are being analyzed (for reserves, to assess damage, etc.). While such diagnostics are "qualitative" (or even subjective), "concept" criteria must be applied in order to obtain the most appropriate assessment of data correlation (and relevance).

A warning — the probability of "analyzing artifacts" in production data varies according to acquisition equipment and practices, but it is inevitable that all analysts will in some form or another find themselves analyzing artifacts in data.

Common examples are poor estimates of bottomhole pressures derived from surface pressures, analysis of very early production data (sometimes even on a regular basis). Such cases help us to recognize that data acquisition is more than frequent measurements — it is a philosophy related to fields such as signal processing, the goal is to diagnose/interpret/analyze the signal, not the noise.

- **"Log-Log" or "Normalized Productivity Index" Plot:** This is a plot of the logarithm of rate (left axis) versus production (or historical) time coupled with the related pseudopressure functions for gas (or the related pseudopressure functions for gas) versus the logarithm of material balance time function (see Nomenclature section for detail). This is a "PTA equivalent" plot — i.e., the plotting functions yield a plot analogous to the "log-log" plot of pressure drop and pressure drop derivative functions versus the appropriate time (or "effective time") function where this plot is used to analyze pressure transient tests. The most relevant reference for this approach is given by Agarwal, et al [Agarwal, et al (1998)]

The log-log plot of \( (\Delta p/q) \) (and its auxiliary functions) versus material balance time is used to diagnose specific flow regimes (infinite-acting radial flow, linear or bi-linear flow (fractured wells), etc.) — which provides orientation as to which portion of the data set should be used to estimate a particular reservoir property (e.g., the infinite-acting radial flow regime yields constant derivative and integral-derivative behavior — from which the permeability can be estimated).

- **Blasingame" or "Advanced Decline Type Curve" Plot:** The so-called "Blasingame" plot [Palacio and Blasingame (1993) and Doublet, et al (1994)] is a "re-plot" of the traditional Fetkovich plot [Fetkovich (1980)], with provisions for a variable rate and pressure histories (as opposed to the
Fetkovich plot, where a constant bottomhole flowing pressure is assumed.

The "Blasingame/Advanced Decline Type Curve Analysis" plot is created by plotting the logarithm of the \( \frac{q}{\Delta p} \) functions (or the related pseudopressure functions for gas) versus the logarithm of appropriate material balance time function (details in Nomenclature). This plot uses rate normalized by pressure drop functions rather than pressure drop normalized by rate functions (e.g., the Normalized Productivity Index plot) and is in some ways a "Fetkovich corrected" plot — where the "correction" is the use of normalized pressure drop rate functions and the material balance time (oil) or material balance pseudotime functions as a means to correct for non-constant rate or pressure functions.

In addition to work already cited for the "Advanced Decline Type Curve" plot, numerous references have been developed for this application, the most relevant of which are:

- Araya and Ozkan (2002) [General treatment]
- Marhaendrajana and Blasingame (2001) [Multwell case]

Each of these references provides orientation and practical application of the "Advanced Decline Type Curve" plot provided for the case presented.

- **"Fetkovich Decline Type Curve" Plot**: The Fetkovich Decline Type Curve Plot is only specifically valid for the case of production at a constant bottomhole pressure [Fetkovich (1980)]. The logarithm of flowrate (left axis) is plotted versus the logarithm of time and the logarithm of cumulative production (right axis) is plotted versus logarithm of time. This plot creates a fairly consistent diagnostic for assessing the quality of the rate data, but this plot does not provide much orientation as a diagnostic plot. The primary "use" of the Fetkovich format plot [\( \log(q) \) and \( \log(N_p) \) versus log (time)] is, at present, as a "log-log history" plot — for presenting data and model results.

In addition to the diagnostic plots given above, there is a substantial body of work given for the generic "diagnosis" of production data. These references identify mechanisms for assessing data quality and relevance, as well as "validation" techniques (e.g., the "flowing material balance" [Mattar and McNeil (1997)]) which compares the production data, not to a reservoir model, but to theoretical considerations such as material balance.

The "pitfalls" reference by Anderson, et al [Anderson, et al (2006)] is prepared based on field cases which demonstrate typical challenges for production data analysis. This work helps to highlight the simple issues (e.g., having the correct estimate of initial reservoir pressure) as well as the detailed procedures to evaluate production data systematically — in order to avoid (or at least minimize) the analysis of artifacts in data.

Another "practical" reference is the work given by Blasingame and Rushing [Blasingame and Rushing (2005)] where this work focuses on the estimation of reserves. While this may not seem like a "diagnostic" reference, the methods proposed in this work can be used to estimate/validate reserves, thus tying the production data to a volume basis. An interesting note is the characterization of production data for reserves extrapolation — the derivation of "basis" plots for the hyperbolic rate decline case yields a mechanism that can be used to clearly and concisely identify the appropriateness of the hyperbolic rate decline model for a particular data case.

**Decline Type Curve Analysis of Production Data**: The use of a reservoir model for the analysis of reservoir or well performance data has been in practice for over 70 years in the petroleum and hydrology literature. However, these methods always consider the performance data to be accurate and consistent — two words that cannot historically be attributed to production data (i.e., measured well rates and pressures).

While pressure transient analysis evolved early, due to data quality and consistency issues, the rigorous analysis of production data lagged substantially, until the early 1970s when Fetkovich [Fetkovich (1980)] presented his seminal work on the analysis of production (rate) data using "decline type curves" developed from rigorous reservoir model solutions (specifically for the constant wellbore pressure case). Fetkovich demonstrated that production data analysis could yield estimates of reservoir properties which are comparable to the results of pressure transient analysis.

The "Fetkovich" approach became quite popular because of its simplicity and consistency. However, it soon became obvious that a method that has, as its basis, the assumption of a constant flowing bottomhole pressure would have limitations in practice (perhaps serious limitations). In the early 1990s the full character of the production data was incorporated into the analysis scheme [Palacio and Blasingame (1993) and Doublet, et al (1994)]. This meant that continuous changes in the rate and pressure history could be considered — and the "Fetkovich" methodology was modified to incorporate rate and pressure drop normalization functions and a material balance-based time function to account for the variable-rate and pressure history.

In recent times "type curves" (or more appropriately, a "static" image of the reservoir performance behavior) have been replaced by dynamic, on-demand modeling in software. The premise of diagnostics and analysis are essentially the same as with "type curves," but now "dynamic" models are the accepted standard for the analysis and interpretation of production and pressure transient test data. Again, the approach of using a "type curve" (static model) or a "dynamic" reservoir model (actually a reservoir simulator) are essentially the same — with the only significant difference being that on-demand modeling provides a much better "matching" process (matching occurs for the data functions as well as the raw production data).

Our presentations include a "type curve" match for each case, which provides orientation and comparison of the various model responses compared to the selected case. Type curve matching also has the benefit of providing the analyst with a (visual) basis for the match. Antagonists argue that type curve analysis unduly biases the analysis process. However; given the accuracy and character of production data functions, it is both appropriate (and prudent) to use a static model — if only to provide an initial match/analysis prior to the dynamic (simulation-based) analysis process.

**Field Case Demonstration Examples**

The purpose of using field cases to demonstrate production data analysis methodologies is to tie the "theory" to the "practice." In theory, production data analysis is identical to pressure transient analysis — provided we have competent data, we can develop a robust and relevant analysis of the data. Unfortunately, comparison of production and pressure transient analyses ends there — the practical aspects of data quality (production data are "low frequency/low resolution" data, while pressure transient data are "high frequency/high resolution" data) and data acquisition (production data are taken passively as "monitoring" data, where pressure transient data are taken as part of a design process to ensure that the characterization of the reservoir is accurate and representative).

**Stepwise Analysis/Interpretation Procedure**

In order to improve the "function" of production data analysis, we propose and employ the following step-by-step process for the diagnosis, analysis, and interpretation of production data:

**Step 1**: *Data Review* → Review "Production History Plot" for data quality/correlation.
Step 2: Data Review → Data correlation check \((p_{ot} \text{ or } p_{pt}) \text{ vs.} \text{ rate plot})\). Crude comparison, only for general trends.

Step 3: Clean/Edit Data for Clarity → Remove spurious data from log-log data plots used for diagnosis.

Step 4: Identify Flow Regimes (Diagnostics) → Identify characteristic flow regimes (normalized PI/Blasingame plots).

Step 5: Compare Data to Reservoir Model → Use "Type Curves" to compare match data with a reservoir model.

Step 6: Refine Model Parameters → Improve match of model parameters \((k, s, x_F, F_{CD}, \ldots \text{ etc.})\) using individual type curves, simulation models, and/or regression methods.

Step 7: Summary History Match → Final "history match" of model and raw well performance data \((p_{ot} \text{ and } q)\).

Example 1 — South America Oil Well

In this example we consider the case of a horizontal oil well from South America. As we stated earlier, the main objective of this paper is to focus on the analysis/interpretation of production data taken "regularly" and "continuously" — using modern production data analysis methods. This example serves as a very good candidate for our purposes as it was reported that the data were taken from continuous (essentially instantaneous) measurements of (surface) oil rates and (bottomhole) pressures. In Fig. 1 (i.e., the "Production History Plot") we note a very good correlation between rates and pressures — indicating that the quality of the data is high, which leads us to a robust analysis expectation.

As a complete demonstration of our analysis/interpretation procedure given above for this example case, we use the following specific stepwise sequence:

**Step 1:** We first review the data using the "Production History Plot," in this case it is seen that the data correlation is excellent. As an aside, one can also analyze the shut-in portion of this data set — however, we strongly believe that given this quality of a data set, limiting the analysis to the shut-in portion (i.e., using pressure transient analysis methods) will prevent the analyst from extracting the maximum information (and value) from the available production history. We note that pressure transient analysis should be performed to confirm the results obtained from production data analysis.

**Step 2:** We perform a secondary review of the data set by plotting the bottomhole pressures versus the flowrates (see Fig. 2). This plot clearly shows that considerable variance exists in the data profile — the initial transient is apparent, as is the depletion profile after the choke change. An advantage of the correlation plot is that spurious/erroneous data are easy to identify.

**Step 3:** We now face the task of editing the data plotting functions for clarity as we begin our diagnostic process. We typically use the pressure drop normalized rate data, \((q/\Delta p)\), as our primary analysis function — but the rate normalized pressure drop function \((\Delta p/q)\) is just as valid, so the analyst is encouraged to use whichever formulation he/she prefers (or optimally, both formulations should be used). The \((q/\Delta p)\) and \((\Delta p/q)\) functions are plotted versus the appropriate material balance time function on log-log coordinates \([N_{b}/q]\) for the oil case, or \((g_{a})\) material balance pseudotime for the gas case (see Nomenclature).

As noted, we prefer the log-log plot of \((q/\Delta p)\) versus material balance time as our base plot for identifying the flow regimes exhibited by the production data (i.e., the reservoir model). As such, spurious data (those data which distort the resolution or yield artifacts) should be removed before proceeding further in establishing the initial reservoir model. In Fig. 3 we again note that a very good "raw" data profile is observed (these data are almost completely free of random noise). The only major issue in the data profile is the erratic behavior at late times — which is an artifact of the choke change and shut-ins (production stoppages). As shown on Fig. 3, these late time data are removed for clarity.

**Step 4:** In this step we prepare and plot the auxiliary data functions based on the edited \((q/\Delta p)\) profile — i.e., the rate integral and rate integral-derivative functions are computed and plotted along with the edited \((q/\Delta p)\) profile to identify the characteristic flow regimes and the reservoir model (similar to approaches used for pressure transient analysis). In Fig. 4 (i.e., the "Diagnostic Data Analysis Plot") we observe that the data trends are smooth and continuous, and present the data signature for a horizontal well — where this observation confirms the given well completion. To this point, the workflow provides the diagnostic methods for production data analysis, where we trace the evidence of data correlation and/or corruption and identify the characteristic flow regimes.

**Step 5:** We now proceed to estimate the reservoir parameters of the well/reservoir system (in this case — \(k, s, N\)). We use the "Decline Type Curves" solution to compare/match the data with a reservoir model (where these data have been diagnosed in Step 4). The type curve match is a simple and efficient tool to match data and estimate the parameters associated with the reservoir model. For this example we have already identified the signature for a horizontal well in Fig. 4 — and in Fig. 5 we match the data with the type curve solution for a particular horizontal reservoir model. The "rate integral" and the "rate derivative" data trends match the reservoir model quite well, but the "rate integral-derivative" trend is skewed off-trend at early times (possibly an effect of the data acquisition at early times).

**Step 6:** Once the match is confirmed on the type curve, we proceed to improve the match of model parameters using user-driven simulation models and/or regression methods. We also incorporate the rate integral \(\beta\)-derivative function [Ilk, et al (2007)] to support the type curve match and flow regime identification (Fig. 6). In Fig. 6 we present the data matched to a single type curve stem, and we again note that the "rate" and "rate integral" data trends match well with the prescribed reservoir model — however; the "rate integral-derivative" and the rate integral \(\beta\)-derivative trends diverge from the type curve trends at early times. Finally, we also note that the rate integral \(\beta\)-derivative trend does confirm reservoir depletion as it begins to stabilize at late times [the characteristic signature of boundary dominated flow is a stabilized \(\beta\)-derivative trend approaching unity (this is a "material balance" signature)].

**Step 7:** Having identified the reservoir model and having established the reservoir parameters for this case, our last step is to verify (or dispute) if our findings agree or not with the raw well performance. The only way to accomplish this task is to generate the pressure and rate model responses (using the superposition principle for the analytical simulation approach, or simply using numerical simulation).

This final "history match" indicates whether or not the performance data functions are consistent with the analysis. If the generated pressures and/or rates do not agree with the raw well performance data, this situation illustrates that either the base data contain errors (provided that the analyst is confident in the reservoir model and its associated parameters) or simply, the reservoir model is incorrect (or insufficient). Our final history match for this case is presented in Fig. 7, where the pressure and rate data trends are compared to the model responses for the case of a horizontal oil well produced as prescribed by the given rate and pressure data, using the reservoir model parameters estimated in the preceding analyses. For this particular case, we believe that any observed mis-match between the data and the selected reservoir model should be attributed primarily to the rate and pressure data (i.e., errors in the raw well performance data) — and secondarily to the reservoir model selected for these data.
For the analysis of this case, we trust that the systematic procedure described in this work is an efficient and effective mechanism that can be used to analyze/interpret production data which are taken "regularly" (daily or month) and/or "continuously" (essentially instantaneously). The most important conclusion for this case is that the data quality defines the analysis, and one could conclude that where continuous measurements are available, expectations for the analysis/interpretation of such data sets should be very high.

Example 2 — Canada (Tight Gas) Well

The second field example considers the case of a tight gas well from Canada. It has been reported that this well was on continuous rate and pressure acquisition system(s) (gas rates measured at surface, pressures measured at bottomhole conditions). Fig. 8 shows the very high data frequency (rates up to 1 point/minute) and we note that the data exhibit an erratic nature — most likely due to the very high data frequency (spurious points are not uncommon when using automated data acquisition systems).

A major issue that we often encounter in the analysis of very high frequency data sets is spurious measurements which are generated by gauge failures, random errors, etc. — any of which can render the data set being voided for analysis. We also note that with the increasing usage of permanent downhole gauge systems in reservoir monitoring applications, such situations (i.e., spurious errors) will be encountered more frequently — and must be recognized and remedied (if possible). In such cases, the proper way to begin the production data analysis is to filter/reduce the data set prior to analysis. Unfortunately, the filtration/reduction effort is not always obvious, and it is not a novice-level task.

Fig. 9 illustrates that the pressure data appear to be held in "near-constant" pressure steps during production — this is not a significant issue, but this behavior does prohibit correlation of the rate and pressure data in a diagnostic sense. In Fig. 10 the \( q_{g}/\Delta p_{p} \) data exhibit a strong "central" profile — minor data editing should provide a clear signature of the reservoir performance. Our initial concept of the reservoir model appears to be that of a vertically fractured well of low fracture conductivity, or a slightly damaged fractured well. After editing the \( q_{g}/\Delta p_{p} \) data and computing its auxiliary functions, we present these results in Fig. 11, and we verify the low conductivity and/or damaged vertical fracture concept.

In this example, we use the "Decline Type Curves" developed for the vertically fractured well in a reservoir with elliptical drainage boundaries. We believe that (very) low permeability/tight gas systems are best represented by the elliptical flow solution. In Fig. 12, the \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions all match the low conductivity elliptical flow solution \( F_{E}=1 \) and \( \xi=4 \) — and we note that the \( q_{g}/\Delta p_{p} \) function does so only weakly. Overall, we have obtained a very reasonable data match, particularly in the context of the raw data functions (very high frequency data, with some questions regarding accuracy/precision).

The \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions as presented in Fig. 13 are "matched" only to the low conductivity fracture, elliptical flow solution \( F_{E}=1 \) and \( \xi=4 \) — and the rate integral \( \beta \)-derivative function is added as a rudimentary confirmation. In fact, all of the plotting functions confirm the proposed model of a fractured well with a low conductivity vertical fracture in a low permeability reservoir with elliptical drainage boundaries. Finally, in Fig. 14 the rate and pressure "model" solutions do follow the rate behavior (quite well). And while the overall pressure trend is matched, the pressure "steps" are not matched as well, suggesting that the pressure data measurements may not be precise. The solutions shown confirm the elliptical flow model and provide a final (albeit approximate) validation of the model and the data.

Example 3 — Mid-Continent US (Tight Gas) Well

This example is interesting in that production is limited to the capacity of the gathering system and the well must be on production at least for a few days in a month to satisfy the lease requirements. Fig. 15 shows the raw well performance data, and we note that there are numerous production stoppages due to the system production capacity. In fact, this case can be analyzed using the conventional pressure transient analysis techniques considering the shut-in portions of the data set (we performed this exercise as a separate validation of our production analysis).

The production data are of good quality (minimal water production), and a competent analysis/modeling of this performance is expected. In the "Pressure-Rate Correlation Plot" (Fig. 16) we observe that the pressure and rate data appear to be only correlated at early times (high gas rates and pressures). The production/shut-in sequences cause any pressure-rate "correlation" trend to be masked or lost (as one would expect). Next, in Fig. 17, it is obvious that the \( q_{g}/\Delta p_{p} \) trend is corrupted due to the cyclical series of production/shut-in sequences. These data should be removed from the diagnostic trend (i.e., the off-trend \( q_{g}/\Delta p_{p} \) data) in order to prevent the diagnostic analysis from being distorted. After removal of the production/shut-in sequences (see Fig. 18), the \( q_{g}/\Delta p_{p} \) and auxiliary functions \( [q_{g}/\Delta p_{p}]_{a} \) and \( q_{g}/\Delta p_{p} \) indicate two (2) possible reservoir signatures — that of an unfractured well or that of a damaged vertically fractured well. We choose to provide an analysis based on each hypothesis (but present the final results in terms of the unfractured well solution as we believe that this case is more reasonable).

First, we match the data to the "Decline Type Curve" solutions for an unfractured well in a bounded circular reservoir. Fig. 19, illustrates that the \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions confirm the (possible) signature of an unfractured well in a bounded circular reservoir. The match of the data functions with the type curve is very good — suggesting that regardless of stimulation, the well behaves as though it is not stimulated. In Fig. 20 the \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions, as well as the rate integral \( \beta \)-derivative function are presented "matched" only to the \( r_{E}=1 \times 10^{5} \) stem, which confirms that formation damage and/or poor stimulation is likely in this case.

We next match the data with the "Decline Type Curves" developed for the vertically fractured wells in a bounded elliptical reservoir. In Fig. 21, the \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions are matched to the high conductivity elliptical flow solution \( F_{E}=1000 \) and \( \xi=4 \).

We believe that this case is that of a fractured well with damage, as the model (or type curve) response always over-estimates the well performance at early times (when damage is most significant). As expected, the \( q_{g}/\Delta p_{p} \), \( q_{g}/\Delta p_{p} \), and \( q_{g}/\Delta p_{p} \) functions, as well as the rate integral \( \beta \)-derivative (data) function do not match the respective model functions at early times (see Fig. 22).

This observation could (and probably should) be seen as an effect of damage on the well, if the well has been stimulated. However, given the behavior of the diagnostic functions at late times, we can also conclude that the well is experiencing depletion flow, so the reserves and contacted in-place fluid estimates determined from this analysis should be considered accurate. Our estimate of permeability lies in the range between 0.005-0.01 millidarcies using the analysis based on each hypothesis (unfractured well or fractured well).

We conclude the analysis of this case by generating the pressure and rate model responses in Fig. 23. Although we have expressed some concern as to the most accurate reservoir model (vertically fractured well with damage effects, or simply, an unfractured well), we obtained an extraordinary "history match" of the rate and pressure data (in this case, the solution for an unfractured well in bounded circular reservoir was used to provide the model response). This result confirms the high quality of the raw well performance data in this example.

Another conclusion drawn from this example is that our successful analysis of this data, using both production analysis and pressure transient analysis methods (i.e., the pressure transient analysis is
performed on the periodic shut-in data), confirms our production analysis methodology, and supports the case for "continuous" data acquisition as a means to evaluate the productivity of the well at any time. This conclusion leads us to make the statement that regardless of the analysis techniques (whether PTA or PA), if the data quality is high, then either analysis (PA or PTA) should yield similar results and complement each other.

**Example 4 — East Texas US (Tight Gas) Well**

The early part of the data (approximately the first year of production) was presented and analyzed by Pratikno et al. [Pratikno, et al (2003)]. We were provided with an update data for this well (the data now totals about 6 years of production). In Fig. 24 we observe that pressure and rate data are well correlated — a few off-trend data are observed, but we believe that these data are not significant compared to the general trend in the data set (and will be removed in a later editing procedure).

This well has been on continuous surveillance for almost 6 years (daily measurement of surface gas rates and surface pressures). The acquisition has been consistent and there have been very few production interruptions. As such, we should therefore expect to develop a very good production data analysis for this case. In the "Pressure-Rate Correlation Plot" (Fig. 25), we note that over time, the calculated bottomhole pressure profile has declined smoothly from about 1000 psia to 500 psia over approximately 6 years. The observation of this pressure-rate correlation confirms the consistency of the reservoir behavior. The transient responses associated with significant shut-in periods (i.e., those shut-in periods lasting more than a few hours) is apparent — and as noted, will be removed during the editing phase.

In Fig. 26, we note a strong (qg/Δp) profile — very minor data editing is warranted (in fact, these data could be analyzed in completely raw form). Based on knowledge of the well completion, as well as prior analysis of this data, the reservoir model should be that of a vertically fractured well with low fracture conductivity (the elliptical flow model for a fractured well should work very well for this case). After some editing and computation of the auxiliary functions [(qg/Δp)1n, (qg/Δp)70, and (qg/Δp)7], Fig. 27 verifies our diagnosis (low conductivity vertical fracture) given based on the trend in Fig. 26. It is worth noting that all of the diagnostic functions yield excellent character in this case.

From our inspection of the data profiles given in Fig. 27, we should expect an outstanding match of the data with the "Decline Type Curve" in this case (i.e., the elliptical flow model). As seen in Fig. 28, the (qg/Δp), (qg/Δp)n, and (qg/Δp)0 functions all match the low conductivity elliptical flow solution ($F_{10}=10$ and $\zeta=0.75$) very well. This is an extraordinary match, and it confirms that vigilance in reservoir monitoring yields the reward of a very consistent reservoir characterization. Further in Fig. 29, the (qg/Δp), (qg/Δp)n, and (qg/Δp)0 functions, as well as the rate integral $\beta$-derivative function are "matched" only to the low conductivity fracture, elliptical flow solution ($F_{10}=10$ and $\zeta=0.75$). It is very important to note that the rate integral $\beta$-derivative function clearly identifies reservoir depletion (i.e., the stabilized $\beta$-derivative data function trend at late times). We also note that the rate integral $\beta$-derivative function confirms the signature of a vertical well with a finite conductivity vertical fracture (i.e., the $\beta$-derivative data function shows a constant trend which is equal to 0.25 at early times).

Finally, using the prescribed model and the reservoir parameter values obtained for this model, we generate the pressure and rate model responses. For this case, the analysis was so consistent using the elliptical boundary model for a low conductivity vertical fracture that we should expect a very coherent history match of the rate and pressure data with the "model" solutions. As we note in Fig. 30, our "history match" of the flowrate data and the reservoir model is both accurate and consistent. Similarly, our match of the calculated bottomhole pressure data and the reservoir model is also consistent, although the match is not as robust as that for the flowrate data.

In summary, this example signifies the importance of the data quality in production data analysis — particularly for cases of low permeability formations. Therefore, we strongly suggest that most gas wells in low permeability formations should have data acquisition programs similar to the one used in this example (i.e., at least daily rate and pressure measurements, acquired using a cost-effective data acquisition system).

**Summary and Conclusions**

**Summary**

We have employed the following field cases as a mechanism to demonstrate current production analysis methodologies:

- South America Oil Well — "continuous" (high frequency) surface rate and downhole pressure measurements.
- Canada (Tight Gas) Well — "continuous" (very high frequency) surface rate and downhole pressure measurements.
- Mid-Continent (US) (Tight Gas) Well — "regular" (daily) surface rate and pressure measurements.
- East Texas (US) (Tight Gas) Well — "regular" (daily) surface rate and pressure measurements.

Each case was successfully diagnosed, interpreted, and analyzed using existing production data analysis methodologies. In particular, we used the set of procedures given in the Stepwise Analysis/Interpretation Procedure section.

The most challenging aspects of this work include the data review stages — the "art" of distinguishing reservoir signature from artifacts is not a novice-level task, the analyst must focus on a comprehensive review of the data, not simply an immediate, best fit exercise. In retrospect, the data editing step was actually quite straightforward — identifying data which are off-trend is relatively easy, and a judicious removal of a point or two near the endpoints can significantly enhance the data signature.

The identification of flow regimes was quite simple — except for Case 3 (Mid-Continent (US) (Tight Gas) Well), where in this case we were informed by the operator that the well had been stimulated using a hydraulic fracture treatment, but the data signature did not support this information. We provided two interpretations for this case — the well was stimulated but is now damaged, or the well was never effectively stimulated. Being that the simplest answer is usually the most reasonable, we performed the analysis sequence assuming that the well had not been stimulated.

As we proceeded to the "analysis" phase, we provided a "feedback" loop of comparing the data to a model (in our case, type curve solutions) and then refined the model parameters using simulation. Given the interpretations obtained (Step 4 of our procedure), the analysis and refinement steps (Steps 5 and 6) were straightforward — and we obtained consistent matches of the analysis data functions and the reservoir model. The only significant challenge in this stage was the horizontal well case (South America Oil Well) where the early time data functions were slightly corrupted (probably due to well cleanup effects).

Our last step in the proposed procedure (Step 7) is the comparison of the raw rate and pressure history to the (simulated) model history for each case. This was performed to ensure that artifacts were not inadvertently incorporated into the analysis. Some influence of artifacts is inevitable, production data are "low resolution/low frequency" data. However, use of the Summary History Match as a closure step helps to ensure that the match of the raw time series data (i.e., the measured rates and pressures) is consistent with the model-based analysis of the data functions (e.g., $(q/\Delta p)$ and $(\Delta p/q)$, and their auxiliary functions).

**Conclusions:**
1. Accurately measured production rate and pressure data should yield a robust and competent interpretation/analysis, with results comparable to estimates obtained from the analysis of pressure transient data.

2. This work illustrates that the process of data review → diagnosis/interpretation → analysis is very effective for the analysis of a wide spectra of production data type. In simple terms, the proposed stepwise procedure should perform well for any representative set of production data (more or less without regard for the frequency of data acquisition).

3. In the analysis of production data, one must remain vigilant — the "analysis of (data) artifacts" is a reality that will always exist. Although unintentional, the analyst must not rely on rote procedures for the analysis/interpretation of production data.

4. An overall history match (model/simulation solution) must always be presented in comparison to the raw rate and pressure data — this is necessary as a validation of the results as well as the process.

**Recommendations/Comment:**
1. Although a general comment, accurate and consistent production data analysis practices must be employed — specifically, management must be persuaded that improved data acquisition is a necessity for good reservoir/production engineering practices.
2. This work prescribes a logical and systematic "procedure" for production data analysis. We encourage the analyst to always perform the data review/data diagnostic steps carefully, if possible, without the bias of the previous analysis lingering on their minds.

**Acknowledgements**
The authors acknowledge the anonymous contributions of data (and discussion) provided for this work. There is no substitute for reality (i.e., field data) when providing demonstration cases to the user audience. We appreciate the data contributions to date, and look forward to continuing our practice of providing "field case" demonstration examples to illustrate sound reservoir engineering processes.

**Nomenclature**

**Variables:**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G$</td>
<td>Original gas-in-place, MSCF</td>
</tr>
<tr>
<td>$G_p$</td>
<td>Cumulative gas production, MSCF</td>
</tr>
<tr>
<td>$h$</td>
<td>Net pay thickness, ft</td>
</tr>
<tr>
<td>$N$</td>
<td>Original oil-in-place, STB</td>
</tr>
<tr>
<td>$N_p$</td>
<td>Cumulative oil production, STB</td>
</tr>
<tr>
<td>$q$</td>
<td>Oil production rate, STBD</td>
</tr>
<tr>
<td>$q_g$</td>
<td>Gas production rate, MSCFD</td>
</tr>
<tr>
<td>$m(p)$</td>
<td>Pseudopressure, psia²/cp</td>
</tr>
<tr>
<td>$\Delta m(p)$</td>
<td>Pseudopressure drop [m(p) - m(p₀)], psia²/cp</td>
</tr>
<tr>
<td>$p_i$</td>
<td>Initial reservoir pressure, psia</td>
</tr>
<tr>
<td>$p_{base}$</td>
<td>Pseudopressure, psia</td>
</tr>
<tr>
<td>$\Delta p_i(p)$</td>
<td>Pseudopressure drop [(\Delta p_i(p)) - (\Delta p_i(p₀))], psia</td>
</tr>
<tr>
<td>$p_{sf}$</td>
<td>Flowing bottomhole pressure, psia</td>
</tr>
<tr>
<td>$p_\bar{p}$</td>
<td>Average reservoir pressure, psia</td>
</tr>
<tr>
<td>$\Delta p$</td>
<td>Pressure drop ((p_{p_{emb}} - p_{p_{w}})), psi</td>
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<tr>
<td>$r_w$</td>
<td>Wellbore radius, ft</td>
</tr>
<tr>
<td>$t$</td>
<td>Time, days</td>
</tr>
<tr>
<td>$t_m$</td>
<td>(gas) Pseudotime, days</td>
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<tr>
<td>$t_m_{mba}$</td>
<td>Material Balance Pseudotime</td>
</tr>
<tr>
<td>$t_m_{ba}$</td>
<td>Material Balance Pseudotime</td>
</tr>
<tr>
<td>$t_m_{gas}$</td>
<td>Material Balance Pseudotime</td>
</tr>
<tr>
<td>$T$</td>
<td>Reservoir temperature, °F</td>
</tr>
<tr>
<td>$z$</td>
<td>Gas compressibility factor</td>
</tr>
<tr>
<td>$F_d$</td>
<td>Dimensionless fracture conductivity</td>
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<tr>
<td>$F_E$</td>
<td>Elliptical fracture conductivity</td>
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**Greek Symbols:**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\gamma_g$</td>
<td>Reservoir gas specific gravity (air = 1)</td>
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<tr>
<td>$\phi$</td>
<td>Porosity, fraction</td>
</tr>
<tr>
<td>$\mu$</td>
<td>Viscosity, cp</td>
</tr>
<tr>
<td>$\xi_0$</td>
<td>Elliptical boundary characteristic variable</td>
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**Subscripts:**

<table>
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<tbody>
<tr>
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<td>Pseudotime</td>
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<tr>
<td>$d$</td>
<td>Derivative or decline parameter</td>
</tr>
<tr>
<td>$D$</td>
<td>Dimensionless</td>
</tr>
<tr>
<td>$Dd$</td>
<td>Dimensionless decline variable</td>
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<tr>
<td>$f$</td>
<td>Fracture</td>
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<tr>
<td>$g$</td>
<td>Gas</td>
</tr>
<tr>
<td>$i$</td>
<td>Integral function or initial value</td>
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<tr>
<td>$id$</td>
<td>Integral derivative function</td>
</tr>
<tr>
<td>$mb$</td>
<td>Material balance</td>
</tr>
<tr>
<td>$pss$</td>
<td>Pseudosteady-state</td>
</tr>
</tbody>
</table>

**Gas Pseudofunctions:**

\[
m(p) = \frac{1}{2} \int_0^p \frac{p - p_{base}}{\mu \partial z} \, dp \quad \text{(Pseudopressure "Ramey" form)}
\]

\[
p_p = \frac{\mu c_i}{\rho_i} \int_0^p \frac{p - p_{base}}{\mu \partial z} \, dp \quad \text{(Pseudopressure "Russell, et al" form)}
\]

\[
t_m = \frac{\mu_g c_i}{\mu_g} \int_0^t \frac{q(t)}{q(t) - q_i} \, dt \quad \text{(Pseudotime)}
\]

\[
t_{m_{mba, gas}} = \frac{\mu_g c_i}{\mu_g} \int_0^t \frac{q(t)}{q(t) - q_i} \, dt \quad \text{(Material Balance Pseudotime)}
\]

**SI Metric Conversion Factors:**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
<th>Conversion Factor</th>
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<tr>
<td>$\text{cp} \times 1.0$</td>
<td>E-03 = Pa·s</td>
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<tr>
<td>$\text{ft} \times 3.048$</td>
<td>E-01 = m</td>
<td></td>
</tr>
<tr>
<td>$\text{md} \times 9.869 \times 10^3$</td>
<td>E-04 = μm²</td>
<td></td>
</tr>
<tr>
<td>$\text{psi} \times 6.894 \times 10^5$</td>
<td>E+00 = kPa</td>
<td></td>
</tr>
<tr>
<td>$\text{bbl} \times 1.589 \times 10^3$</td>
<td>E-01 = m³</td>
<td></td>
</tr>
</tbody>
</table>

*Conversion factor is exact.

**References**

Diagnostic Methods for Production Data Analysis:


Decline Type Curve Analysis of Production Data:


Figure 1: Example 1 (South America Oil Well) Production History Plot. Good correlation of rates and pressures — data taken from continuous measurements of (surface) oil rates and (bottomhole) pressures.

Figure 2: Example 1 (South America Oil Well) Pressure-Rate Correlation Plot. Considerable variance exists in the data profile. Initial transient is apparent, as is the depletion profile after the choke change.
Figure 3: Example 1 (South America Oil Well) Preliminary Analysis Review Plot. Very good "raw" data profile, some erratic behavior at late times — most likely an artifact of the choke change and shut-ins (production stoppages).

Figure 4: Example 1 (South America Oil Well) Diagnostic Data Analysis Plot. The "edited" data show a smooth and continuous trend, the data signature for a horizontal well is evident, which confirms the well completion.
Figure 5: Example 1 (South America Oil Well) Decline Type Curve Match (Horizontal Well). The "integral" data trend (blue squares) matches well with the reservoir model, but the "integral-derivative" trend (red triangles) is skewed by off-trend at early times (possibly an effect of the data acquisition).

Figure 6: Example 1 (South America Oil Well) Single-Trend Decline Type Curve Match (Horizontal Well). We again note that the "rate" and "integral" data trends match well with the reservoir model, but the "integral-derivative" (red triangles) and the rate integral β-derivative trends (green boxes) are off-trend at early times. We note that the rate integral β-derivative trend (green squares) does confirm reservoir depletion.
Figure 7: Example 1 (South America Oil Well) Analysis Summary Plot. The pressure and rate data trends are compared to the model responses for the case of a horizontal oil well produced as prescribed by the rate and pressure data and the reservoir model profiles are generated using parameters estimated in the preceding analyses. For these data, mismatches should be attributed primarily to the rate and pressure data — and secondarily to the reservoir model selected for these data.
Figure 8: Example 2 (Canada Gas Well) Production History Plot. Well was on continuous rate and pressure acquisition system(s) (gas rates at surface, pressures at bottomhole (as reported to the authors)). The erratic nature of the observed behavior is most likely due to the very high data frequency (rates of up to 1 point/minute).

Figure 9: Example 2 (Canada Gas Well) Pressure-Rate Correlation Plot. The pressure data appear to be held in "near-constant" pressure steps during production — this is not a significant issue, but this behavior does prohibit correlation of the rate and pressure data (in a diagnostic sense).
**Figure 10:** Example 2 (Canada Gas Well) Preliminary Analysis Review Plot. Strong "central" data profile \((q_i/\Delta p_p)\) — minor data editing should provide a clear signature of the reservoir performance. Initial reservoir model appears to be that of a vertically fractured well of low fracture conductivity, or a slightly damaged fractured well.

**Figure 11:** Example 2 (Canada Gas Well) Diagnostic Data Analysis Plot. The \((q_i/\Delta p_p)\) function and its auxiliary functions \((q_i/\Delta p_p)_i\) [rate integral] and \((q_i/\Delta p_p)_{id}\) [rate integral-derivative] verify the low conductivity and/or damaged vertical fracture concept.
Figure 12: Example 2 (Canada Gas Well) Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). The \( \frac{q_g}{\Delta p_p} \), \( \frac{q_g}{\Delta p_p} \), and \( \frac{q_g}{\Delta p_p} \) functions all match the low conductivity elliptical flow solution \( (F_E = 1 \text{ and } \epsilon_0 = 4) \) — with note that the \( \frac{q_g}{\Delta p_p} \) function does so only weakly. Overall, a very reasonable data match, particularly in the context of the raw data functions (very high frequency, with some questions regarding accuracy/precision).

Figure 13: Example 2 (Canada Gas Well) Single-Trend Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). The \( \frac{q_g}{\Delta p_p} \), \( \frac{q_g}{\Delta p_p} \), and \( \frac{q_g}{\Delta p_p} \) functions as presented are "matched" only to the low conductivity fracture, elliptical flow solution \( (F_E = 1 \text{ and } \epsilon_0 = 4) \) — the rate integral/\( \beta \)-derivative function is added as a simple confirmation. In fact, all of the plotting functions confirm the proposed model of a fractured well with a low conductivity vertical fracture in a low permeability reservoir with elliptical drainage boundaries.
Figure 14: Example 2 (Canada Gas Well) Analysis Summary Plot. The rate "model" solution does follow the rate behavior (quite well). And while the overall pressure trend is matched, the pressure "steps" are not matched well, suggesting that the pressure data measurements may not be precise. The solutions shown confirm the elliptical flow model and provide a final (albeit approximate) validation of the model and the data.
Figure 15: Example 3 (Mid Continent (US) Gas Well) Production History Plot. This case is somewhat unusual in that the production is limited to the capacity of the gathering system, and the well can only produce a few days a month (to hold the lease contract, the well must be on production). This case is a test of the variable-rate/variable pressure analysis methodology. The data are of good quality (minimal water production), and a competent analysis/modeling of this performance is expected.

Figure 16: Example 3 (Mid Continent (US) Gas Well) Pressure-Rate Correlation Plot. The pressure and rate data appear to be only correlated at early times (high gas rates and pressures). The production/shut-in sequences cause any "correlation" trend to be masked or lost.
Figure 17: Example 3 (Mid Continent (US) Gas Well) Preliminary Analysis Review Plot. The \((q_g/\Delta p_p)\) trend is "corrupted" by the production/shut-in sequences — where these data must be removed from the diagnostic trend \((i.e., \ (q_g/\Delta p_p))\) data.

Figure 18: Example 3 (Mid Continent (US) Gas Well) Diagnostic Data Analysis Plot. After removal of the production/shut-in sequences, the \((q_g/\Delta p_p), (q_g/\Delta p_p)_i, \) and \((q_g/\Delta p_p)_{id}\) functions indicate two (2) possible scenarios — an unfractured well signature, or the signature of a damaged vertically fractured well. We provide an analysis based on each hypothesis.
Figure 19: Example 3 (Mid Continent (US) Gas Well) Decline Type Curve Match (Unfractured Well, Radial Flow System). The \((q_g/\Delta p_p)\), \((q_g/\Delta p_p)_i\), and \((q_g/\Delta p_p)_d\) functions confirm the (possible) signature of an unfractured well in a bounded circular reservoir. The match of the data functions with the type curve is very good, suggesting that regardless of stimulation, the well behaves as though it is not stimulated.

Figure 20: Example 3 (Mid Continent (US) Gas Well) Single-Trend Decline Type Curve Match (Unfractured Well, Radial Flow System). The \((q_g/\Delta p_p)\), \((q_g/\Delta p_p)_i\), and \((q_g/\Delta p_p)_d\), and the rate integral \(\beta\)-derivative functions are “matched” only to the \(r_{Dd}=1\times10^4\) stem, which confirms that formation damage and/or poor stimulation is likely in this case.
Example 3 (Mid Continent (US) Gas Well) Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). In this match the ($q_g/\Delta p_p$), ($q_g/\Delta p_p$)$_i$, and ($q_g/\Delta p_p$)$_{id}$ functions are matched to the high conductivity elliptical flow solution ($F_e=1000$ and $\xi_0=4$). We believe that this case is that of a fractured well with damage, as the model (or type curve) response always over-estimates the well performance at early times (when damage would have most profound effect).

Example 3 (Mid Continent (US) Gas Well) Single-Trend Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). As noted, the ($q_g/\Delta p_p$), ($q_g/\Delta p_p$)$_i$, and ($q_g/\Delta p_p$)$_{id}$ functions, as well as rate integral $\beta$-derivative function, do not match the respective model functions at early times. This observation could (and probably should) be seen as an effect of damage on the well, if the well has been stimulated. However, given the behavior of the diagnostic functions at late times, we can also conclude that the well is experiencing depletion flow, so the reserves and contacted in-place fluid estimates determined from this analysis should be considered accurate.
Figure 23: Example 3 (Mid Continent (US) Gas Well) Analysis Summary Plot. Although we have some concern as to the most accurate reservoir model (vertically fractured well with damage effects, or simply an unfractured well), we obtained an extraordinary "history match" of the rate and pressure data (in this case, the solution for an unfractured well in bounded circular reservoir was used to provide the model response).
Example 4 (East Texas Gas Well) Production History Plot. This well is an evolving case history in "how to do things right" regarding the practical aspects of reservoir engineering. The well has been on continuous surveillance for almost 6 years (daily measurement of surface gas rates and surface pressures). The rate and pressure data are well-correlated by direct inspection, and we should expect to develop a very good production data analysis for this case.

Example 4 (East Texas Gas Well) Pressure-Rate Correlation Plot. Over time, the calculated bottomhole pressure profile has declined smoothly from about 1000 psia to 500 psia over more than 5 years. As such, the pressure-rate correlation simply confirms this behavior, and does illustrate the transient responses associated with significant shut-in periods (i.e., those shut-in periods lasting more than a few hours).
Figure 26: Example 4 (East Texas Gas Well) Preliminary Analysis Review Plot. Very strong ($q_g/\Delta p_p$) profile — very minor data editing is warranted, these data could be analyzed in completely raw form. Based on knowledge of the well completion, as well as prior analysis of this data, the reservoir model should be that of a vertically fractured well with a vertical fracture of low conductivity (the elliptical flow model for a fractured well should work very well for this case).

Figure 27: Example 4 (East Texas Gas Well) Diagnostic Data Analysis Plot. All of the diagnostic functions [$q_g/\Delta p_p$, $(q_g/\Delta p_p)_i$, and $(q_g/\Delta p_p)_{id}$] yield outstanding diagnostic character after minor editing — verifying the proposed low conductivity vertical fracture concept.
Figure 28: Example 4 (East Texas Gas Well) Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). In this case, the \( \frac{q_g}{\Delta p} \), \( \frac{q_g}{\Delta p_i} \), and \( \frac{q_g}{\Delta p_{id}} \) functions all match the low conductivity elliptical flow solution \( (F_E = 10 \text{ and } \xi_0 = 0.75) \) very well. This is an outstanding match and it confirms that vigilance in reservoir monitoring earns the reward of a very consistent reservoir characterization.

Figure 29: Example 4 (East Texas Gas Well) Single-Trend Decline Type Curve Match (Vertically-Fractured Well, Elliptical Flow System). The \( \frac{q_g}{\Delta p} \), \( \frac{q_g}{\Delta p_i} \), \( \frac{q_g}{\Delta p_{id}} \) functions, as well as the rate integral-\( \beta \)-derivative function, are "matched" only to the low conductivity fracture, elliptical flow solution \( (F_E = 10 \text{ and } \xi_0 = 0.75) \). We note an excellent match across all functions and all flow regimes — this is a truly extraordinary case!
Figure 30: Example 4 (East Texas Gas Well) Analysis Summary Plot. For this case, the analysis was so consistent using the elliptical boundary model for a low conductivity vertical fracture, that we should expect a very consistent history match of the rate and pressure data with the "model" solutions. The match of the flowrate data and the reservoir model is both accurate and consistent. Similarly, the match of the calculated bottomhole pressure data and the reservoir model is also consistent, although the match is not as robust as that for the flowrate data.