Characterization of Well Performance in Unconventional Reservoirs using Production Data Diagnostics
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Abstract
Production analysis and forecast in unconventional reservoirs are challenging tasks due to high degree of uncertainty and non-uniqueness associated with well/reservoir properties. At this point the importance of diagnosis of production data to check the data consistency and to identify flow regimes has become significant. In addition, we believe that producing wells in various unconventional reservoirs exhibit unique production performance behavior due to geology, phase behavior, and completion practices. Therefore, the identification of the related performance behavior is crucial for development and forecast purposes.

The primary objective of this work is to apply diagnostic methods to investigate and understand production performance characteristics of the wells producing in unconventional reservoir systems. For our purposes, we present examples from various shale gas plays.

We propose the use of various forms of rate-time and rate-time-pressure plots for production data diagnostics. In particular, this work presents the utilization of the dimensionless $\beta_{q,cp}$-derivative formulation (i.e., logarithmic derivative of the rate function with respect to logarithm of time) to identify production behavior characteristics. We also propose the use of several diagnostic plots to identify performance characteristics and data consistency. In addition the use of average rate functions are presented for better resolution.

Introduction
Unconventional reservoir systems can best be described as hydrocarbon accumulations which are difficult to be characterized and produced by conventional exploration and production technologies. Recently unconventional reservoir systems such as tight gas sands, shale gas, tight/shale oil, and coalbed methane reservoirs have become a significant source of hydrocarbon production and offer remarkable potential for reserves growth. Due to the low to ultra-low permeability of these reservoir systems, well stimulation operations (e.g., single or multi-stage hydraulic fracturing, etc.) are required to establish production from the formations at commercial rates.

The advances in technology to produce and develop ultra-low permeability reservoirs such as shale gas reservoirs bring the difficulties and uncertainty associated with well performance. The uncertainty is mainly due to the lack of our complete understanding of the production mechanisms and behavior of these reservoir systems. And the difficulty is therefore associated with establishing the long term production decline in these reservoirs.

In terms of production analysis in unconventional reservoirs the solutions based on the "linear flow" concept (Wattenbarger et al. 1998; El-Banbi and Wattenbarger 1998) are frequently used with the inclusion of effective fracture network length accounting for a single vertical fracture. Bello and Wattenbarger (2010) extend the previously mentioned linear flow solutions to account for the natural fracture network in shale gas reservoirs by proposing a linear dual porosity solution.

For horizontal wells completed with multiple fractures in ultra-low permeability reservoirs, we suggest that multiple-fractured horizontal well model should be used for analysis. The references on this particular well model in fact extend to late 1980s. van Kruysdijk and Dullaert (1989) provide an analytical solution based on "boundary-element method". van Kruysdijk and Dullaert show that at early time dominant flow is linear, perpendicular to the fracture face until pressure transients of the individual fractures begin to interfere leading to a compound linear flow regime at late times (linear flow is
seen towards the collections of fractures during compound linear flow regime). Eventually, pseudoradial flow should occur,
however we must note that the occurrence of pseudoradial flow regime should not be expected in ultra-low permeability
shale gas reservoirs. Other analytical solutions for horizontal wells with multiple fractures include the works by Soliman,
Hunt, and El Rabaa (1990), Larsen and Hegre (1991), Guo and Evans (1993), Larsen and Hegre (1994), Horne and Temeng

The use of only production data (i.e., rate-time data) to estimate future production has been an industry practice since the
introduction of the Manual for the Oil and Gas Industry under the Revenue Act of 1918 by the United States Internal
Revenue Service (1919). Arps (1945) presents the derivation of empirical exponential and hyperbolic rate decline relations,
which are still the widely used relations for production extrapolations of oil and gas wells, and can be assumed as valid for a
variety of producing conditions for practical purposes. We note that the exponential and hyperbolic relations are only
applicable for the boundary-dominated flow regime and the improper use of Arps' equations can yield inconsistent results and
erroneous future production values. The common industry practice for production extrapolation in unconventional reservoirs
is to use the hyperbolic relation, but as mentioned before the hyperbolic relation is strictly applicable during boundary-
dominated flow. Application of the hyperbolic relation to transient flow often results in significant overestimation of future
production. For reference the hyperbolic rate decline and cumulative production relations are given as:

\[ q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \quad \text{(Definition of the loss-ratio)} \quad (1) \]

\[ G_p(t) = \frac{q_i}{(1 - bD_i t)} \left[ 1 - (1 + bD_i t)^{-1/b} \right] \quad \text{(Derivative of the loss-ratio)} \quad (2) \]

According to Arps' definition, the value of the \( b \)-parameter is constant and should lie between 0 and 1. If the \( b \)-parameter
value is higher than 1, the extrapolation of Eq. 2 to infinity yields infinite cumulative production. When hyperbolic rate
decline relation is applied to rate-time data in unconventional reservoirs, we usually observe \( b \)-parameter values higher than 1
which might lead to overestimation of future production. To prevent overestimation of future production, production forecast
with hyperbolic rate decline relation can be switched to exponential rate decline relation at a specified time (based on the
knowledge of a constant percentage decline value). This procedure (or the so called "modified hyperbolic relation") is a
practical way to constrain future production. However, rate-time data characteristics indicate that the nature of rate-time data
is in fact not hyperbolic when the hyperbolic rate decline model parameters are computed continuously using data. In
particular, the computed \( b \)-parameter data trend indicates that the value of \( b \)-parameter would not be constant throughout
the producing life of the well.

The issues related to the use of "conventional" rate decline relations to estimate future production in "unconventional"
reservoirs, have led us to focus on the character of the rate-time data. Our primary objective is to understand the
characteristic behavior of rate-time data in unconventional reservoirs, and to develop appropriate rate decline relation(s)
based on the characteristic behavior. For these purposes, we recall the original definitions of the "loss-ratio" and the "loss-
ratio derivative", which were previously introduced by Johnson and Bollens (1927). These definitions are given as:

\[ \frac{1}{D} = -\frac{dq(t)}{dt} \quad \text{(Definition of the loss-ratio)} \quad (3) \]

\[ b = \frac{d}{dt} \left[ \frac{1}{D} \right] = -\frac{d}{dt} \left[ \frac{q(t)}{dq(t)/dt} \right] \quad \text{(Derivative of the loss-ratio)} \quad (4) \]

Continuous evaluation of Eqs. 3 and 4 requires numerical differentiation, which might be problematic if the data quality is
poor. Usually the data quality is significantly affected by non-reservoir affects (e.g., well clean-up, liquid loading, etc.) and
operational changes (e.g., choke changes, refracturing, etc.). Therefore, vigilant editing is warranted and redundant/erroneous
data points have to be removed prior to differentiation.

Based on the loss-ratio and the derivative of the loss-ratio definitions, the \( D \)- and \( b \)-parameters are computed continuously
and the character of the computed trends is evaluated. It is observed that the computed \( D \)-parameter trend exhibits power-law
behavior (i.e., straight line on log-log scale) as a function of time and the computed \( b \)-parameter data trend is not constant
contrary to the hyperbolic rate decline relation (Ilk et al. 2008, Mattar et al. 2008). Therefore, it can be stated that "power-
law" behavior of the loss-ratio can be considered as a general characteristic of rate-time data in unconventional reservoirs,
and we observe this behavior in almost all the cases in unconventional reservoirs (Ilk 2010). Power-law exponential rate-
decline relation is derived from this observation (Ilk et al. 2008).
\[ q(t) = \hat{q}_i \exp\left(-\hat{D} t^n - D_w t\right) \]  

Valko (2009) presents another form of Eq. 5 (namely the "stretched exponential function"), which is given as:

\[ q(t) = \hat{q}_i \exp\left(-\frac{t}{\tau}\right)^\theta \]  

In this work we focus on three different shale gas plays in North America. The first play (considered as Field A in this work) is a formation composed of siltstone and dark grey shale, with dolomitic siltstone in the base and fine grained sandstone towards the top. Particularly the formation of interest is a highly unusual \( \approx 400-500\) ft thick package of continuous, gas charged siltstone with a very small clay content. The formation is normal pressured with pressure gradients \( \approx 0.45-0.5 \) psi/ft.

Field B is a black, organic rich shale of Upper Jurassic age, which is deposited with mainly heavier clay minerals, silica, and calcite. The depth of the Field B ranges from approximately 10,000 ft in the northwest part to 14,000 ft in the southeast. It is overpressured with pressure gradients higher than 0.9 psi/ft. Field C is a Middle Devonian age black, low density, organic rich shale at an approximate average depth of 5,000-6,000 ft.

**Objectives of this Work**

The following objectives are stated for this work:

1. To characterize the performance of various shale gas fields considered in this study with the use of diagnostic plots. Time-rate and Time-Pressure-Rate forms of various diagnostic plots are used in this process.

2. To develop an understanding of the performance characteristics, stimulation/completion effectiveness, effect of geology on well performance by using diagnostic plots.

3. To develop/improve new diagnostic plots which could contribute to this work's sought objectives.

**Characterization of Well Performance**

For identifying well performance characteristics, diagnostic plots are utilized. Characteristic features, which are exhibited by production data, are identified with the use of diagnostic plots. Diagnostic plots help to identify flow regimes (e.g., bi-linear/linear flow, compound linear flow, etc.) and compare data to a well/reservoir model. Although the complexity of unconventional reservoirs prevents the establishment of a rigorous analytical solution (at present) to account for the actual well/reservoir model that is applicable for unconventional reservoirs, we can at least observe the characteristic behavior(s) of the wells producing in unconventional reservoirs using diagnostic plots. Once the characteristic features of well performance data are identified, we can make use of semi-analytical and/or numerical solutions for tuning to the data and estimating the flow efficiency, completion effectiveness, reservoir properties, and consequently future production. If we identify similarly producing wells from diagnostics, we can also group the wells accordingly and generate the characteristic performance trend for the selected wells producing in a particular field.

**Diagnostic Plots:** In this work we propose to use the following diagnostic plots (Table 1) for our purposes. These plots are the main plots that we make use of in distinguishing the performance of the wells studied in this work. In this study we introduce the so-called "pressure drop normalized instantaneous absolute open flow" versus cumulative production plot. We believe that this plot has significant diagnostic value which will be illustrated in the field examples later in this section. For reference, we provide the derivation of the pressure drop normalized instantaneous absolute open flow equation below.

Stabilized flow rate equation is given as:

\[ q_g = C(p_i^2 - p_{wf}^2) \]  

Based on Eq. 7, the "Absolute Open Flow" rate is defined as:

\[ q_{AOF} = C(p_i^2 - 0) \]  

We can obtain an "instantaneous absolute open flow" rate relation below by solving Eqns. 7 and 8:

\[ q_{ins,AOF} = \frac{q - p_i^2}{p_i^2 - p_{wf}^2} \]
Eq. 9 can be normalized by the pressure drop to partially account for bottomhole pressure variations.

\[
q_{\text{ins,AOF}} = \frac{q_{g}}{(p_i - p_{wf})} \frac{p_i^2}{p_i^2 - p_{wf}^2}
\] ................................. (10)

We also use the \( \beta_{q,cp} \)-derivative for our purposes. For reference \( \beta_{q,cp} \)-derivative is given as:

\[
\beta_{q,cp}(t) = -\frac{d\ln[q(t)]}{d\ln[t]} = -\frac{t}{q(t)} \frac{dq(t)}{dt}
\] ................................. (11)

The \( \beta_{q,cp} \)-derivative function has significant diagnostic value as the power-law type flow regimes such as linear flow, bilinear flow, etc. appear as constants on log-log scale. Since numerical differentiation is involved, in some cases the computed \( \beta_{q,cp} \)-derivative function can not be interpreted. For these cases we recommend the use of "average rate" data (simply instantaneous cumulative production divided by corresponding time value) instead of the rate data.

We make use of production data of 12 wells from Field A, 7 wells from Field B, and 14 wells from Field C to illustrate the use of diagnostic plots. Each of the diagnostic plots is presented for the three fields. Figs. 1a-1c present the flowrate data versus production time for the three fields. It is obvious that Field B has steeper decline rates than the other fields. Also Field C has more complex production profiles than the other two fields (most probably due to operational issues/water production). Figs. 2a-2c demonstrate the average rate versus production time. With the use of average rate, it is relatively easier to distinguish the performance of the wells. In Figs. 3a-3c average rate data is normalized by the pressure drop. One clear result is that for Field B, the production of Well 1 is distinct from the other wells. This is due to the fact that Well 1 is producing in a different area in the play.

Figs. 4a-4c present the cumulative gas production and flowrate data. The distinct performance of Well 1 in Field B is clearly identified. Figs. 5a-5c show the computed \( D \)-parameter versus time plots. For all the fields the change of the computed \( D \)-parameter data is power-law leading to the conclusion that power-law exponential function is more suitable for rate-time analysis. When data is smoothed by the average rate formulation, the power-law behavior can easily be identified (Figs. 6a-6c). Since numerical differentiation is involved twice for the \( b \)-parameter computation, the computed \( b \)-parameter data do not have good resolution in Figs. 7a-7c and Figs. 8a-8c. However, we can still get an average estimate for the \( b \)-parameter value if the hyperbolic relation is used for rate-time analysis. For Fields A and C, the \( b \)-parameter seem to be in between 1.5 and 2. On the other hand, the \( b \)-parameter value for Field B is more likely close to 1.

Figs. 9a-9c and Figs 10a-10c present \( \beta_{q,cp} \)-derivative functions for three fields. It is obvious that the average rate formulation for the \( \beta_{q,cp} \)-derivative has more resolution. Based on our observations, we can conclude that Field A seems to have more productivity (i.e., shallower trend for the \( \beta_{q,cp} \)-derivative). Pressure drop normalized instantaneous AOF rate data are presented in Figs. 11a-11c and Figs. 12a-12c. The low productivity of wells in Field B is observed from the behavior of the wells. Again the production behavior of Well 1 in Field B is distinct from the others. We also note that the differences in the production of the wells are attributed to the completion and location (i.e., geology). For example, Well 7 in Field C on Fig 12c has relatively poorer completion than the other wells in the field. Also the best well in Field A (Well 12) has the best completion and producing in the highest productive area in the field. The rest of the plots (Figs. 13-17) can be considered as "reservoir diagnostics" to identify flow regimes and also data consistency/issuses. It is worth to mention that linear flow regime can easily be identified for Field A using these plots. Linear flow is also apparent for Field C, but the data issues with the wells in Field C prevent complete identification. On the other hand, it is obviously apparent that linear flow does not exist for Field B. It can also be observed that for Field B, the productivity of the wells drop severely with time pointing to the issues with production from a high pressure-high temperature reservoir (e.g., excessive drawdown, compaction, etc.).
Summary and Conclusions

Summary: In this work we attempt to use production data diagnostics to identify performance characteristics of wells producing in unconventional reservoirs. For our purposes we focus on three (3) shale gas plays in North America. We utilize various forms of time-rate and time-pressure-rate type diagnostic plots. Diagnostic plots are helpful in terms of identifying similarly producing wells and better performing wells. Also, flow regimes (e.g., linear flow, bi-linear flow, fracture interference, etc.) can be identified using diagnostic plots.

Based on diagnostics we identify completion/stimulation effectiveness of the wells investigated in this study and also try to distinguish more productive zones/areas/locations based on the production performance of the wells. From a simple point of view, the wells investigated in this study are modeled with the power-law exponential decline relation to yield upper and lower bounds for EUR value specific to each play. Using this information future development scenarios can be performed.

Conclusions: We state the following conclusions based on this work:

1. Diagnostic analysis of production data is significant in the characteristic understanding of well performance in unconventional reservoirs. In addition, quality and consistency of production data can be verified using diagnostic plots. Certain features as well as flow regimes can be identified using diagnostic plots. In this work we evaluate the performance of wells producing in three different shale gas plays in North America. Within the play similarly producing wells, completion effectiveness, productivity of a specific location can be recognized with the use of diagnostic plots.

2. We believe that there is no single diagnostic plot which is superior or preferable to the rest. Instead we suggest as many diagnostic plots as possible to achieve higher resolution. Certain diagnostic plots would perform better based on various circumstances (e.g., location, completion, rock/fluid properties, etc.). We also suggest the use of various forms of time-rate and time-pressure-rate type diagnostic plots.

3. It is noted that the $\beta_{q,cp}$-derivative is an efficient tool for diagnostic purposes. The advantage of the $\beta_{q,cp}$-derivative is sourced from its formulation, which results in a dimensionless term allowing the analyst to compare the production behavior of the wells in a robust way. $\beta_{q,cp}$-derivative responses in the three fields clearly exhibit the differences in production behavior. While $\beta_{q,cp}$-derivative is an efficient tool for diagnostics, it may suffer from data quality since numerical differentiation of data is involved. For these cases average rate formulation of the $\beta_{q,cp}$-derivative can be used for more resolution.

4. Based on diagnostics, it can clearly be distinguished that each field has unique performance characteristics. Field A and Field C exhibit long term linear behavior whereas linear flow almost does not exist for Field B. Therefore, we advise caution for the use of workflows/solutions which are designed to evaluate well performance in unconventional reservoirs without paying attention to specific characteristics of each play. We believe that any workflow/procedure for the evaluation of well performance in a certain play should be adaptive to the play's characteristics and these characteristics can only be identified via production data diagnostics.
5. It is shown that production performance is strongly correlated with geology (location), and well completion. For example, we clearly show that better well completion yields better recovery for wells producing in the same area.

6. Our future efforts will focus on adding more wells into our diagnostic procedure for the plays considered in this work and we will seek to identify distinct productive areas based on location and completion over a broader range. Finally, model-based analysis and/or numerical simulation will be utilized to provide a more robust representation of production extrapolation to obtain EUR values.

**Nomenclature**

*Variables:*

- \( b \): Arps’ decline exponent, dimensionless
- \( D \): Reciprocal of loss ratio, \( D^{-1} \)
- \( D_i \): Initial decline constant for exponential and hyperbolic rate relation, \( D^{-1} \)
- \( D_e \): Power-law exponential model parameter, \( D^{-1} \)
- \( \hat{D}_i \): Power-law exponential model parameter, \( D^{-1} \)
- \( EUR \): Estimate of ultimate recovery, BSCF
- \( G_p \): Cumulative gas production, MSCF or BSCF
- \( G_{p,max} \): Maximum gas production (at a specified time limit), MSCF or BSCF
- \( n \): Time exponent for power-law exponential model, dimensionless
- \( p_i \): Initial reservoir pressure, psia
- \( p_{wf} \): Flowing bottomhole pressure, psia
- \( q_{AOF} \): "Absolute Open Flow" Gas flowrate, MSCF/D
- \( q_{ins,AOF} \): Instantaneous "Absolute Open Flow" Gas flowrate, MSCF/D
- \( q_g \): Gas flowrate, MSCF/D
- \( q_i \): Initial production rate for exponential and hyperbolic relations, MSCF/D or STB/D
- \( \hat{q}_i \): Power-law exponential model parameter, MSCF/D or STB/D
- \( t \): Production time, days

*Greek Symbols:*

- \( \beta_{q,cp} \): Beta-derivative function (constant-pressure), dimensionless
References


Fig. 1a — Production history plot for all wells (Field A). Gas flowrate versus time.

Fig. 1b — Production history plot for all wells (Field B). Gas flowrate versus time.
Fig. 1c — Production history plot for all wells (Field C). Gas flowrate versus time.

Fig. 2a — Production history plot for all wells (Field A). Average gas flowrate versus time.
Fig. 2b  —  Production history plot for all wells (Field B). Average gas flowrate versus time.

Fig. 2c  —  Production history plot for all wells (Field C). Average gas flowrate versus time.
Fig. 3a — Production history plot for all wells (Field A). Pressure drop normalized average gas flowrate versus time.

Fig. 3b — Production history plot for all wells (Field B). Pressure drop normalized average gas flowrate versus time.
Fig. 3b — Production history plot for all wells (Field C). Pressure drop normalized average gas flowrate versus time.

Fig. 4a — Production history plot for all wells (Field A). Cumulative gas production versus gas flowrate.
Fig. 4b — Production history plot for all wells (Field B). Cumulative gas production versus gas flowrate.

Fig. 4c — Production history plot for all wells (Field C). Cumulative gas production versus gas flowrate.
Fig. 5a — Time-Rate diagnostic plot for all wells (Field A). Computed $D$-parameter versus time.

Fig. 5b — Time-Rate diagnostic plot for all wells (Field B). Computed $D$-parameter versus time.
Fig. 5c — Time-Rate diagnostic plot for all wells (Field C). Computed $D$-parameter versus time.

Fig. 6a — Time-Average Rate diagnostic plot for all wells (Field A). Computed $D$-parameter (from average rate) versus time.
Fig. 6b — Time-Average Rate diagnostic plot for all wells (Field B). Computed $D$-parameter (from average rate) versus time.

Fig. 6c — Time-Average Rate diagnostic plot for all wells (Field C). Computed $D$-parameter (from average rate) versus time.
Fig. 7a — Time-Rate diagnostic plot for all wells (Field A). Computed $b$-parameter versus time.

Fig. 7b — Time-Rate diagnostic plot for all wells (Field B). Computed $b$-parameter versus time.
Fig. 7c — Time-Rate diagnostic plot for all wells (Field C). Computed $b$-parameter versus time.

Fig. 8a — Time-Average Rate diagnostic plot for all wells (Field A). Computed $b$-parameter (from average rate) versus time.
Fig. 8b — Time-Average Rate diagnostic plot for all wells (Field B). Computed $b$-parameter (from average rate) versus time.

Fig. 8c — Time-Average Rate diagnostic plot for all wells (Field C). Computed $b$-parameter (from average rate) versus time.
Fig. 9a — Time-Rate diagnostic plot for all wells (Field A). Computed $\beta_{q,cp}$-derivative versus time.

Fig. 9b — Time-Rate diagnostic plot for all wells (Field B). Computed $\beta_{q,cp}$-derivative versus time.
Fig. 9c — Time-Rate diagnostic plot for all wells (Field C). Computed $\beta_{q,cp}$-derivative versus time.

Fig. 10a — Time-Average Rate diagnostic plot for all wells (Field A). Computed $\beta_{q,cp}$-derivative (average rate) versus time.
**Fig. 10b** — Time-Average Rate diagnostic plot for all wells (Field B). Computed $\beta_{q,cp}$-derivative (average rate) versus time.

**Fig. 10c** — Time-Average Rate diagnostic plot for all wells (Field C). Computed $\beta_{q,cp}$-derivative (average rate) versus time.
Fig. 11a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Pressure drop normalized instantaneous AOF versus time.

Fig. 11b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Pressure drop normalized instantaneous AOF versus time.
Fig. 11c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Pressure drop normalized instantaneous AOF versus time.

Fig. 12a — Time-Pressure-Average Rate diagnostic plot for all wells (Field A). Pressure drop normalized instantaneous average AOF versus time.
Fig. 12b — Time-Pressure-Average Rate diagnostic plot for all wells (Field B). Pressure drop normalized instantaneous average AOF versus time.

Fig. 12c — Time-Pressure-Average Rate diagnostic plot for all wells (Field C). Pressure drop normalized instantaneous average AOF versus time.
Fig. 13a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Rate normalized pressure drop versus production time.

Fig. 13b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Rate normalized pressure drop versus production time.
Fig. 13c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Rate normalized pressure drop versus production time.

Fig. 14a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Rate normalized pressure drop versus material balance time.
Fig. 14b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Rate normalized pressure drop versus material balance time.

Fig. 14c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Rate normalized pressure drop versus material balance time.
SPE 147604 — Field A
Time-Pressure-Rate Diagnostic Plot for All Wells
(Pressure Drop Normalized Rate versus Production Time)

Legend:
- Well 1
- Well 2
- Well 3
- Well 4
- Well 5
- Well 6
- Well 7
- Well 8
- Well 9
- Well 10
- Well 11
- Well 12

Production Time, t, Days
Pressure Drop Normalized Rate, q_i/\Delta p

Fig. 15a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Pressure drop normalized rate versus production time.

SPE 147604 — Field B
Time-Pressure-Rate Diagnostic Plot for All Wells
(Pressure Drop Normalized Rate versus Production Time)

Legend:
- Well 1
- Well 2
- Well 3
- Well 4
- Well 5
- Well 6
- Well 7

Production Time, t, Days
Pressure Drop Normalized Rate, q_i/\Delta p

Fig. 15b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Pressure drop normalized rate versus production time.
Fig. 15c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Pressure drop normalized rate versus production time.

Fig. 16a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Pressure drop normalized rate versus material balance time.
Fig. 16b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Pressure drop normalized rate versus material balance time.

Fig. 16c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Pressure drop normalized rate versus material balance time.
Fig. 17a — Time-Pressure-Rate diagnostic plot for all wells (Field A). Rate normalized pressure drop versus square root of production time.

Fig. 17b — Time-Pressure-Rate diagnostic plot for all wells (Field B). Rate normalized pressure drop versus square root of production time.
Fig. 17c — Time-Pressure-Rate diagnostic plot for all wells (Field C). Rate normalized pressure drop versus square root of production time.